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2008
Integrated Resource Plan
Volume I

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

May 28, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2008 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: Foot 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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1. EXECUTIVE SUMMARY

PacifiCorp's 2008 Integrated Resource Plan (2008 IRP), representing the 10th plan submitted to state regulatory commissions, presents a framework of future actions to ensure PacifiCorp continues to provide reliable, reasonable-cost service with manageable risk to its customers. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties.

The key elements of the 2008 IRP include a finding of resource need—focusing on the 10-year period 2009-2018, the preferred portfolio of supply-side and demand-side resources to meet this need, and an action plan that identifies the steps the Company will take during the next two to four years to implement the plan. The resources identified in the 2008 IRP preferred portfolio are considered proxy resources that guide procurement efforts, and do not constitute the actual resources that would be acquired as part of future procurement initiatives.

Significant changes reflected in this IRP relative to the 2007 IRP (filed in May 2007) include:

- A decrease in resource need: the system becomes short on capacity in 2011 rather than 2010 due to lower forecasted loads and new resource additions.
- Acquisition of the 520 megawatt (MW) Chehalis gas plant and 175 MW of additional wind resources added in 2008.
- New IRP guidelines issued by the Oregon Public Utility Commission on the treatment of carbon dioxide (CO_2) regulatory risk.
- Incorporation of the Energy Gateway Transmission project in the portfolio analysis.
- State commission 2007 IRP acknowledgment orders calling for modeling methodology changes and the expansion of resource options to consider, including energy efficiency measures (Class 2 demand-side management programs) and additional renewable energy technologies such as solar and geothermal.

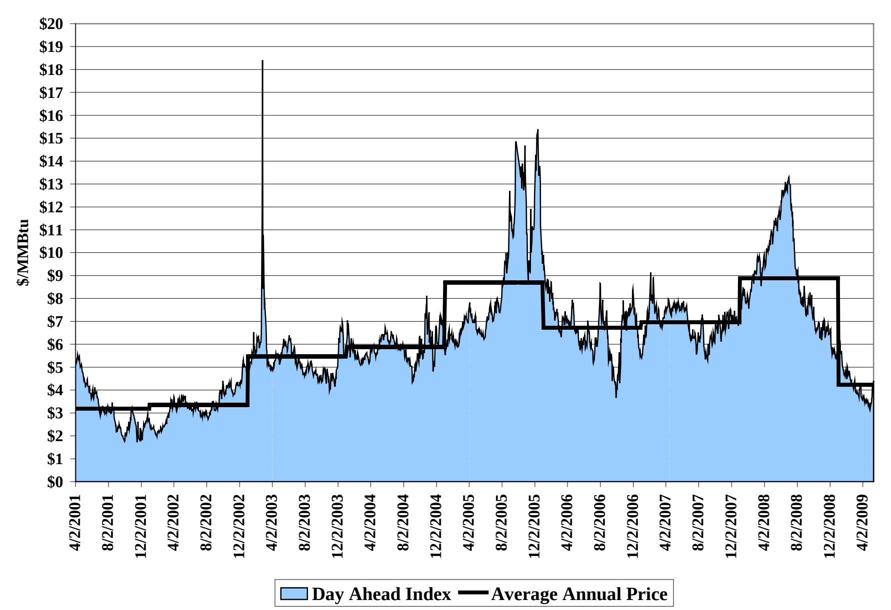
THE INTEGRATED RESOURCE PLANNING ENVIRONMENT

- For capital expenditure planning, the Company's challenge has been to minimize customer rate impacts in light of a substantial capital spending requirement needed to address customer load growth, support government environmental and energy policies, and maintain transmission grid reliability. To address this challenge, PacifiCorp is scrutinizing capital projects for cost reductions or deferrals that make economic sense in today's market environment.

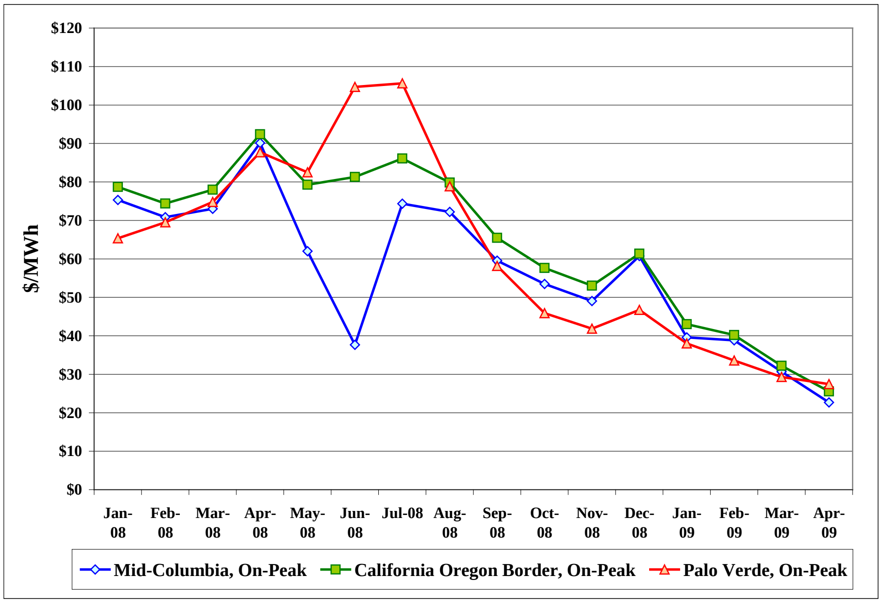
- An additional planning challenge has been to respond to and predict the demand response impacts of the economic recession and financial crisis. The Company is currently seeing a continuation of significant industrial and commercial sector demand destruction. This will translate into a reduction in resource need for the near-term. Nevertheless, the depth of the economic recession and the pace of a recovery are uncertain, complicating the resource requirements picture. The table below compares the Company's peak load forecasts prepared in November 2008 and February 2009 without reductions from energy efficiency programs, showing the differences through 2018. The February 2009 load forecast was prompted by a review of actual loads through January 2009.

Load Forecast	**Coincident Peak Load, Megawatts**									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
November 2008	10,150	10,371	10,640	10,991	11,281	11,501	11,798	12,127	12,384	12,674
February 2009	9,987	10,248	10,599	10,930	11,232	11,459	11,781	12,034	12,383	12,679
Difference	(163)	(123)	(41)	(61)	(49)	(42)	(17)	(93)	(1)	5

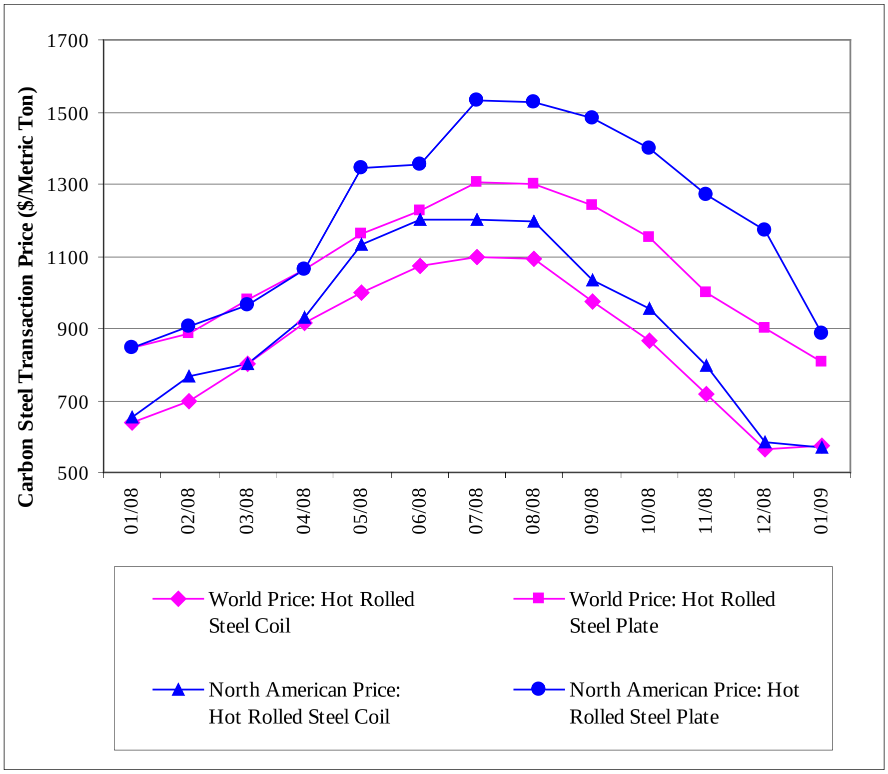
- At the same time, volatile economic conditions and commodity prices, combined with regulatory uncertainty, have complicated the planning picture, requiring the Company to continuously re-evaluate input assumptions and resource acquisition strategies throughout this planning cycle. For example the three charts below vividly illustrate the dramatic price movement of Henry Hub day-ahead natural gas prices, day-ahead wholesale electricity prices, and carbon steel prices during the time this IRP was developed.



Source: IntercontinentalExchange, OTC Day-ahead Index



Source: IntercontinentalExchange, OTC Day-ahead Prices



Source: MEPS (International) LTD, MEPS Steel Prices On-line

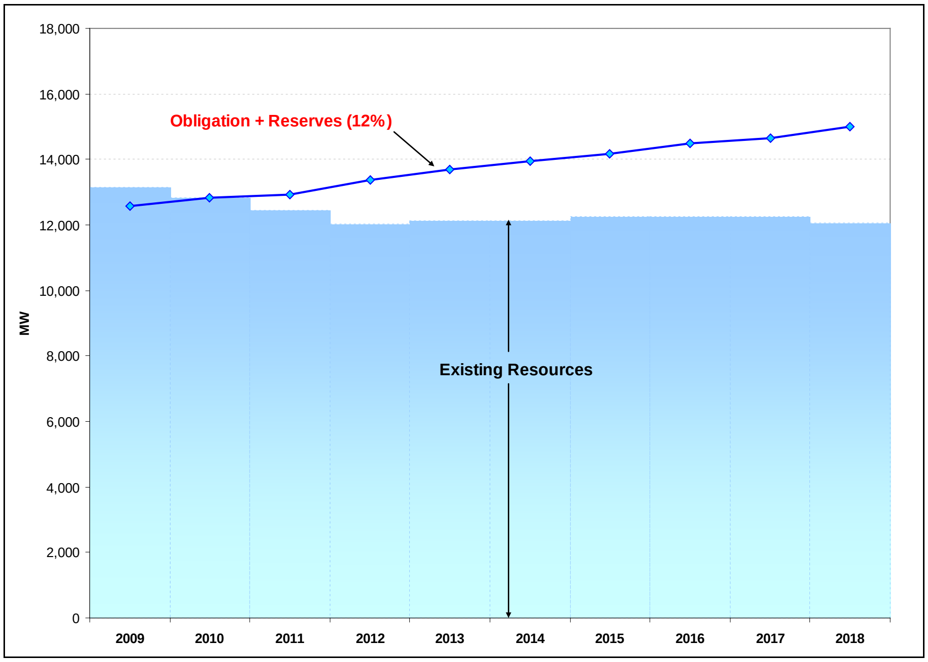
◆ The significant price drops in fuels and forward wholesale power in late 2008 and early 2009 signal near-term opportunities to lower power supply costs through market purchases before the Company needs to commit to a large new thermal power plant. If construction markets continue to soften as several experts predict, this will create additional cost-saving opportunities through lower plant prices.

- The 2008 IRP reflects evolution of PacifiCorp's corporate resource planning approach. In early 2008, PacifiCorp embarked on a strategy to more closely align IRP development activities and the annual 10-year business planning process. The purpose of the alignment was to adopt consistent planning assumptions, ensure that business planning is informed by the IRP portfolio analysis and that the IRP accounts for near-term resource affordability, and improve resource planning transparency for public stakeholders.

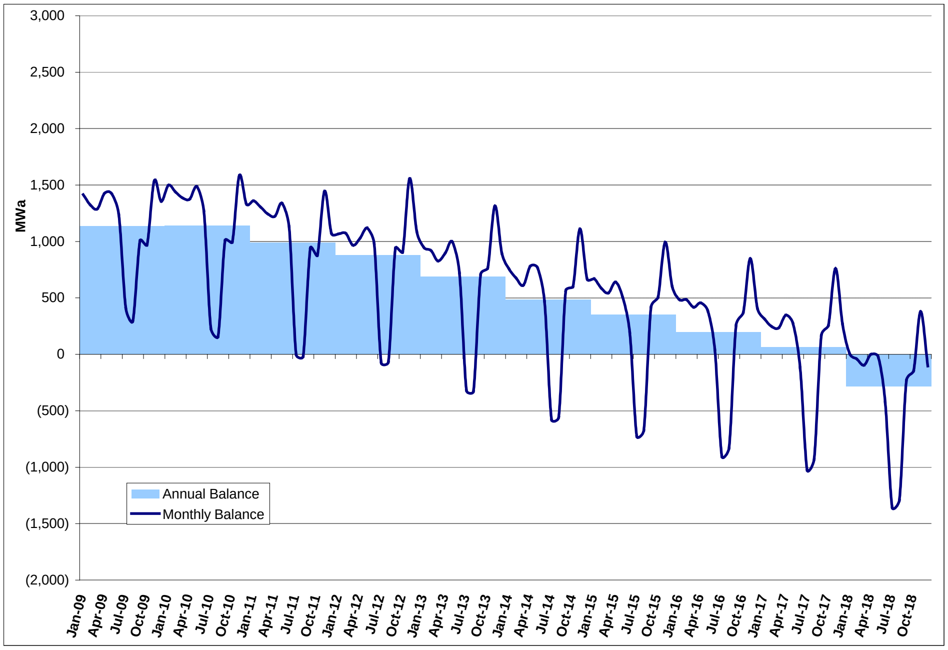
- PacifiCorp's 2008 IRP accounts for the Energy Gateway Transmission project. For the 2008 IRP cycle, the Company treated the various planned transmission segments as existing resources for portfolio modeling purposes. Going forward, Gateway transmission segments will be reevaluated from an integrated resource planning perspective during the IRP and annual business planning cycles.

RESOURCE NEEDS AND PORTFOLIO MODELING

- The resource need accounts for load growth, sales obligations, existing resources, and a 12 percent planning reserve margin. Based on a November 2008 load forecast, PacifiCorp experiences a capacity deficit beginning in 2011—the system is short by 498 megawatts (MW). This deficit increases to 1,936 MW in 2012 and 3,528 MW by 2018. The following chart shows the growth in the gap between resources and capacity, requirements based on a 12 percent capacity reserve requirement. The capacity deficit is driven by a coincident system peak load growth rate of 2.5 percent for 2009-2018, and expiration of major power contracts such as the Bonneville Power Administration peaking contract in August 2011.



On an energy basis, the system begins to experience summer short positions by 2012 as indicated in the following chart that shows the gap between available energy and load obligations.



◆ To determine how best to address the capacity deficits, PacifiCorp developed 57 resource portfolios using a capacity expansion model that optimizes resource choice according to a variety of input assumptions and capacity planning criteria. The Company simulated most of these portfolios—developed with a combination of carbon dioxide regulatory costs, forward electricity and natural gas prices, load forecast scenarios, and other variables—using a production cost model that accounts for stochastic variation in key variables. These stochastic variables include loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal resource availability.

◆ PacifiCorp's state utility commissions require the Company, through their IRP standards and guidelines, to develop a portfolio that is least-cost after accounting for risk, uncertainty, and the long-run public interest. To make this determination, PacifiCorp uses a wide range of portfolio performance measures that capture cost, risk, and supply reliability attributes. The Company focuses on seven measures and a weighted composite scoring scheme to isolate the top-performing portfolios. The three measures given the most weight for scoring purposes include the following:

- Risk-adjusted Present Value of Revenue Requirements (45% weight)
- Customer rate impact – the average annual change in the customer dollar-per-megawatt-hour price for the period 2010 through 2028 (20% weight)
- Carbon dioxide cost exposure – reflects a portfolio's potential for avoiding worst-case cost outcomes given CO_2 regulatory cost uncertainty (15% weight)

PacifiCorp focused its final portfolio performance evaluation on the four portfolios with the best performance scores, comparing them on the basis of individual measure performance and considering other factors such as fuel source diversity and risks not captured in the portfolio modeling (for example, procurement and construction management risks).

THE 2008 IRP PREFERRED PORTFOLIO

- PacifiCorp's 2008 IRP preferred portfolio consists of a diverse mix of resources dominated by renewables, demand-side management, gas-fired resources, and firm market purchases. The major resources for the 2009-2018 planning period consist of the following:
  - Renewables:
    - Wind: 1,313 MW
    - Geothermal: 35 MW
    - Major hydroelectric upgrades: 75 MW in 2012-2014
  - Demand-side management
    - Energy efficiency: 904 MW
    - Dispatchable load control: 205 to 325 MW
  - Gas-fired capacity: 831 MW in the 2014-2016 period
  - Coal plant turbine upgrades: 170 MW of emissions-free capacity
  - Firm market purchases: Ranging from 50 MW to 1,400 MW on an annual basis, contingent on the timing and amounts of long-term resource acquisitions

The table below shows the incremental resource additions by year.

		Capacity, MW										Cumulative Total
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	
East												
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-	200
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	128
	Geothermal	-	-	-	-	35	-	-	-	-	-	35
	Wind	99	249	-	100	100	100	150	100	100	50	1,048
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4	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	532
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800	
West												
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	42
	Swift Hydro Upgrades [2/]	-	-	-	25	25	25	-	-	-	-	75
	Wind	45	20	200	-	-	-	-	-	-	-	265
	CHP	1	1	1	1	2	2	2	2	2	2	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	372
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582	

[1/] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.

[2/] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

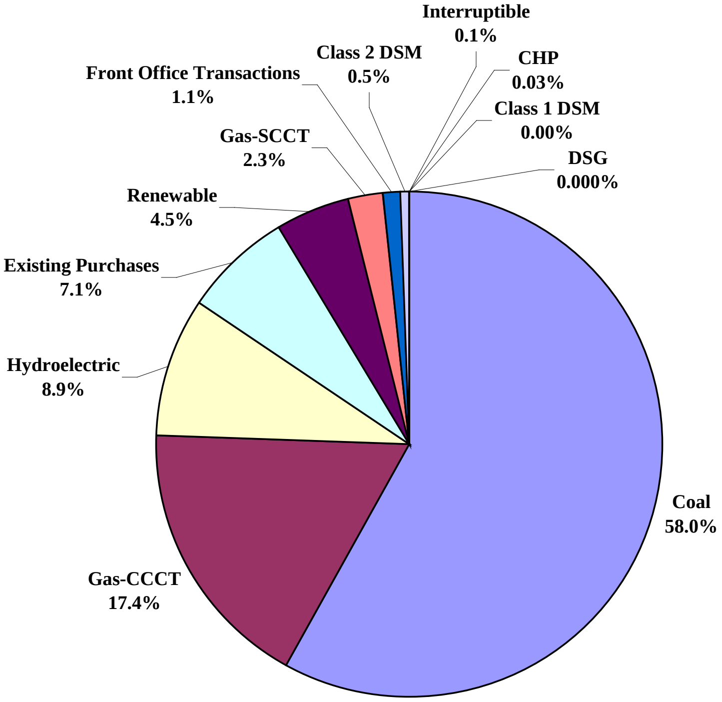
* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

- The capacity expansion model determined the amount and timing of renewables resources subject to annual system-wide renewable portfolio standard generation requirements established from existing state targets in place as of late 2008. PacifiCorp manually spread the wind resource quantities relatively evenly across all years of the 10-year business-planning period to support rate and capital spending stability, balance the timing risks associated with uncertain CO_2 costs and the possibility of federal renewable production tax credit expiration, among other benefits.

- PacifiCorp is on pace to exceed the previous renewable resource amount identified in the Company's 2007 Renewable Energy Action Plan filed in May 2007 (1,400 MW by 2015), and the amount identified in the 2007 IRP Update report filed in June 2008 (2,000 MW by 2013).[1] Since 2005, the Company's projected renewable resource inventory has grown by 1,404 MW, accounting for existing resources and those under construction, contract, or included in the capital budget. The incremental renewables identified in the 2008 IRP preferred portfolio and action plan bring the target to about 2,040 MW by 2013. The projected renewables inventory exceeds 2,540 MW by 2018, which represents 18.5% of PacifiCorp's owned generation capability in that year.

- The pie charts below show the resource generation mix in megawatt-hours for 2009 and 2018, assuming that a $45/ton CO_2 tax is in place beginning in 2013 with 2% annual inflation.

2009 Resource Energy Mix with Preferred Portfolio Resources
($45 CO2 Tax)



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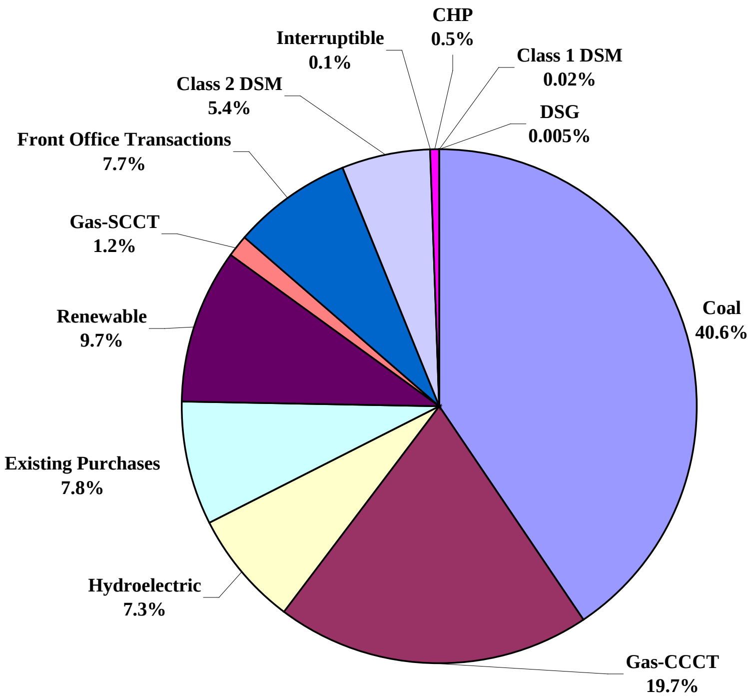
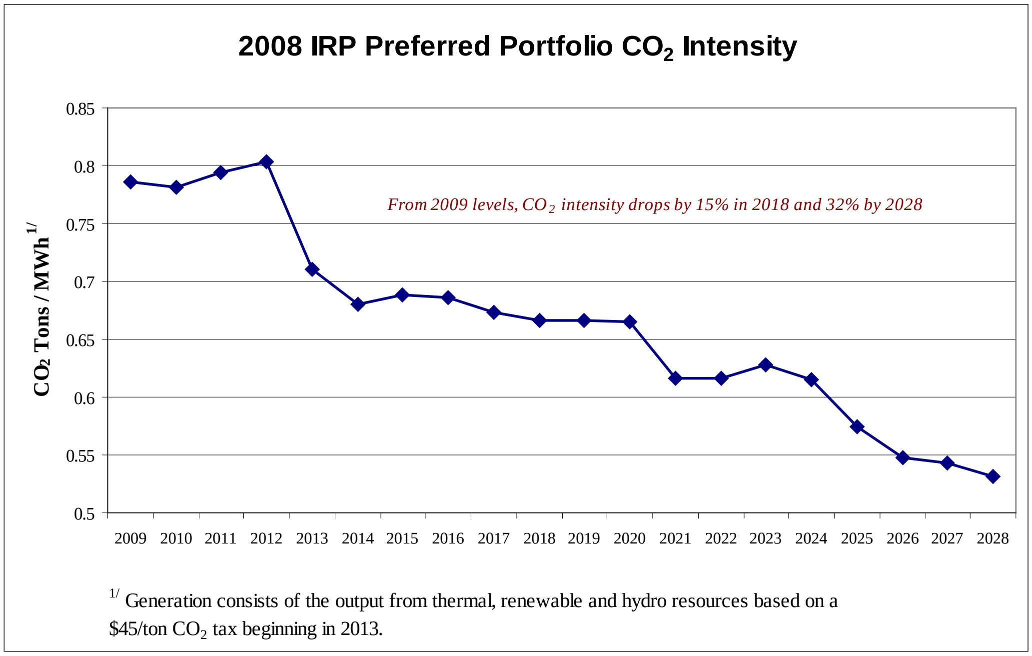
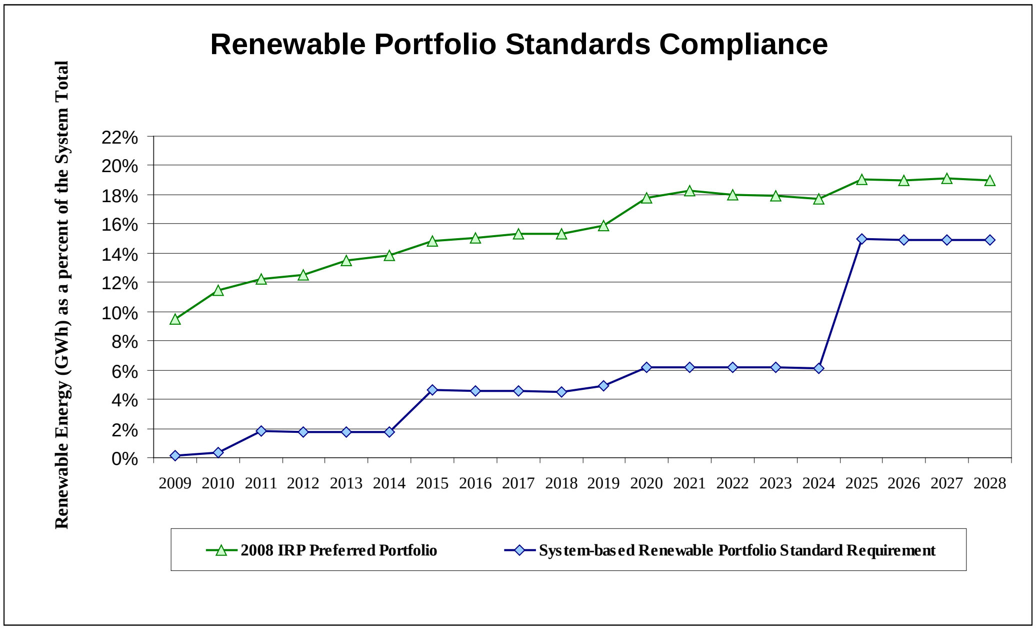
[1] Both of these documents are available at PacifiCorp's IRP Web site. The link to the Renewable Energy Action Plan is http://www.pacificorp.com/File/File74767.pdf. The link to the 2007 IRP Update is http://www.pacificorp.com/File/File82304.pdf.



2018 Resource Energy Mix with Preferred Portfolio Resources
($45 CO2 Tax)

- The increasing mix of clean resources—renewables and demand-side management—reduces the carbon intensity of PacifiCorp's generation fleet and positions the Company well for meeting future climate change and renewable resource requirements. The following two charts show the declining trend in CO_2 emissions per MWh of generation, and how the preferred portfolio complies with existing jurisdictional renewable portfolio standards expressed as a percent of system load.





The addition of energy efficiency resources—reaching 4.2 million kWh by 2018—reduces the system coincident peak load from a 2.7% average annual growth rate (2009-2018) to 1.9%. The addition of flexible natural gas resources supports the aggressive expansion of intermittent renewable generation while meeting incremental base load and intermediate load needs. The role of new firm market purchases is to help replace expiring long-term power purchases, and, by adjusting volumes up or down, provide resource flexibility to manage the volatility and uncertainty in load forecasts, commodity prices, and capital costs.

◆ Relative to the preferred portfolio reported in the 2007 IRP Update report (June 2008), the 2008 preferred portfolio relies on significantly less firm market purchases for the period covered in common (2009-2017). For gas resources, the major difference is the addition of a simple-cycle gas plant in 2016; with the acquisition of the Chehalis plant in 2008, there is negligible change in the amount of combined-cycle gas capacity. The 2008 IRP relies more heavily on distributed generation resources, while differences in wind and Class 2 DSM are minimal. The following table shows the annual resource differences for the two preferred portfolios (2008 IRP less the 2007 IRP Update).

Resource Difference - 2008 IRP Preferred Portfolio less 2007 IRP Update

		Capacity, MW											Total
	Resource	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2008-2017**
East	Gas Combined Cycle (2x1)		-	-	-	(1,096)	-	570	-	-	-	-	(526)
	IC Aero SCCT		-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement		-	-	-	201	-	-	-	-	-	-	201
	Coal Plant Turbine Upgrades		(18)	7	(5)	(12)	2	14	-	8	-	-	(4)
	Geothermal, Blundell 3		-	(35)	-	-	35	-	-	-	-	-	-
	Wind	36 [2/]	(201)	149	(100)	(100)	100	(100)	150	100	100	50	134
	Distributed Generation		6	(13)	6	6	6	6	8	8	8	8	42
	Firm Market Purchases		75	50	150	279	(140)	(546)	(598)	(572)	(66)	800	NA
West	Chehalis CCCT	509 [2/]	-	-	-	-	-	-	-	-	-	-	509
	Coal Plant Turbine Upgrades		-	(8)	(9)	(5)	(5)	-	-	-	-	-	(28)
	Swift Hydro Upgrades*		-	-	-	-	-	-	-	-	-	-	-
	Wind	139 [2/]	45	20	-	-	(100)	-	-	-	-	-	104
	Distributed Generation		2	2	2	2	3	3	3	3	3	3	25
	Firm Market Purchases	(400)	(400)	(657)	(677)	(311)	30	(55)	(100)	(333)	(609)	582	NA
DSM [3/]	Energy Efficiency (Class 2 DSM)	(67)	2	2	(2)	(3)	1	2	3	2	5	87	(55)

[1/] Acquisition of the Chehalis 509 MW combined-cycle plant in Washington.

[2/] For 2008, actual wind additions totaled 545 MW, compared to the planned amount of 370 MW in the 2007 IRP Update

[3/] Expansions of the existing Utah Cool Keeper program and dispatchable irrigation programs are treated as existing resources. Relative to the 2007 IRP Update quantities, the incremental DSM planned expansions reach 525 MW by 2018.

[4/] For the 2007 IRP Update, Class 2 DSM was treated as a decrease to load rather than as a resource included in the preferred portfolio.

◆ Although the Company could not accommodate a comprehensive portfolio evaluation based on the February 2009 load forecast without contravening certain state IRP filing requirements, PacifiCorp was nevertheless able to conduct a preferred portfolio sensitivity analysis with it. Combining the February 2009 load forecast with the input assumptions from which the original preferred portfolio was derived, PacifiCorp developed an alternate portfolio using its the capacity expansion model.

  - A 2014 combined-cycle combustion turbine (CCCT) resource in the original preferred portfolio was fixed in that same year for the sensitivity analysis model run, owing to the small capacity deficits that ranged from 61 MW in 2012 to 93 MW in 2016.
  - The capacity expansion model determined that a 2016 intercooled aeroderivative SCCT was no longer needed, and that deferral and modest reductions in firm market purchases was cost-effective combined with an increase in customer standby generation and addition of utility-scale biomass resources.

◆ Since the relative resource impact of the February 2009 load forecast is minimal until 2016, PacifiCorp decided to retain the IC aero SCCT in the preferred portfolio. Also supporting this decision is the uncertainty over the timing and pace of an economy recovery, combined with the short lead-time for a gas peaking resource and the potential need for such resources to support wind integration. Consideration of the timing and type of gas resources and other resource changes will be handled as part of a comprehensive assumptions update and portfolio analysis to be conducted for the next business plan and 2008 IRP update.

THE 2008 IRP ACTION PLAN

- The 2008 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study completion. The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties. The current volatile economic and regulatory environment will likely require near-term alteration to resource plans as a response to specific events and improved clarity concerning the direction of the economy and government energy and environmental policies.

- Resource information used in the 2008 IRP, such as capital and operating costs, is consistent with that used to develop the Company's business plan completed in December 2008. However, it is important to recognize that the resources identified in the 2008 IRP preferred portfolio are proxy resources and act only as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

- The table below constitutes PacifiCorp's 2008 IRP action plan.

2008 IRP Action Plan

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	2009 - 2018	Acquire an incremental 1,400 MW of renewables by 2018, in addition to the already planned 75 MW of major hydroelectric upgrades in 2012-2014; PacifiCorp's projected renewable resource inventory by 2018 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 269 MW of wind resources in 2010 that are currently in the project pipeline, 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 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 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 solar and emerging technologies, government financial incentives, and procure 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 at the state and federal levels, and adjust the renewable acquisition timeline accordingly*
2	Firm Market Purchases	2009 - 2013	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until no sooner than the beginning of summer 2014 • Acquire the following resources: – Up to 1,400 MW of economic front office transactions on an annual basis as needed through 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) • Resources will be procured through multiple means: (1) reactivation of the suspended 2008 All-Source RFP in late 2009, which seeks third quarter summer products and customer physical curtailment

Action Item	Category	Timing	Action(s)
			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 2009 load forecast • *Acquire incremental transmission through Transmission Service Requests to support resource acquisition*
3	Peaking / Intermediate / Base-load Supply-side Resources	2012 - 2016	Procure long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame • 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 in late 2009 – The Company plans to submit Company resources (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.*
4	Plant Efficiency Improvements	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 2016, which are expected to add 128 MW of incremental in the east and 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*[2] • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules*
5	Class 1 DSM	2009-2018	Acquire at least 200 - 300 MW of cost-effective Class 1 demand-side management programs for implementation in the 2009-2018 time frame • *Pursue up to 200 MW of expanded Utah Cool Keeper program participation by 2018* • *Pursue up to 130 MW of additional cost-effective class 1 DSM products(90 MW in the east side and 30 MW in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound*

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

Action Item	Category	Timing	Action(s)
			in load growth resulting from economic recovery Procure through the currently active 2008 DSM RFP and subsequent DSM RFPs • For 2009-2010, 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.
6	Class 2 DSM	2009-2018	Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa • *Procure through the currently active DSM RFP and subsequent DSM RFPs*
7	Class 3 DSM	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*
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 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
9	Planning Process Improvements	2009-2010	Portfolio modeling improvements • Complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level

Action Item	Category	Timing	Action(s)
			- 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 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 - Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for 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
10	Transmission	2009-2011	Obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief - Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona To 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
11	Transmission	2010	Permit and build Utah/Idaho/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief - Permit and construct a 345 kV line between Populus to Terminal
12	Transmission	2012	*Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* - *Permit and construct a 500 kV line between Mona and Oquirrh*

Action Item	Category	Timing	Action(s)
13	Transmission	2014	*Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct 230 kV and 500 kV line between Windstar and Populus* • *Permit and construct a 345 kV line between Sigurd and Red Butte*
14	Transmission	2016	*Permit and build Northwest/Utah/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Populus and Hemingway*
15	Transmission	2017	*Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Aeolus and Mona*

2. INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP, representing the 10th plan submitted, fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties.

This IRP also builds on PacifiCorp's prior resource planning efforts and reflects continued advancements in portfolio modeling and performance assessment. These advancements include (1) extensive expansion of resource options considered, (2) a wider range of portfolios developed with alternative input assumptions using the Company's capacity expansion optimization tool, (3) more detailed presentation of renewable portfolio standard compliance requirements, and (4) adoption of a portfolio preference scoring methodology that incorporates probability-weighting of CO_2 cost futures and importance weighting of various portfolio performance measures. The portfolio preference scoring methodology explicitly incorporates CO_2 risk into the portfolio selection decision, and structures the key performance measures into a composite ranking system that shows, in a transparent fashion, how PacifiCorp chose the optimal resource plan among several alternatives.

Finally, this IRP reflects evolution of PacifiCorp's corporate resource planning approach. In early 2008, PacifiCorp embarked on a strategy to more closely align IRP development activities and the annual 10-year business planning process. The purpose of the alignment was to:

- provide corporate benefits in the form of consistent planning assumptions,
- ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns that are the province of capital budgeting, and;
- improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

The planning alignment strategy also follows the 2007 adoption of the IRP portfolio modeling and analysis approach for Requests for Proposals (RFP) bid evaluation.[3] This latter initiative was part of PacifiCorp's effort to unify planning and procurement under the same analytical framework.

This chapter outlines the components of the 2008 IRP, summarizes the role of the IRP, describes the IRP/business plan alignment strategy and progress to date, and provides an overview of the public process.

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[3] For its 2012 Base Load RFP, PacifiCorp used the IRP Monte Carlo production cost simulation model to evaluate costs and risks of portfolios with bid resources optimized with different input assumptions (CO_2 cost, fuel prices, and planning reserve margins).

2008 INTEGRATED RESOURCE PLAN COMPONENTS

The basic components of PacifiCorp's 2008 IRP, and where they are addressed in this report, are outlined below.

- The set of IRP principles and objectives that the Company adopted for this IRP effort, as well as a discussion on customer/investor risk allocation (this chapter).
- An assessment of the planning environment, including PacifiCorp's 2009 business plan—developed in 2008 and approved by MidAmerican Energy Holdings Company (MEHC) board of directors in December 2008, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- A description of PacifiCorp's transmission planning effort and its linkages to the integrated resource planning effort (Chapter 4).
- A resource needs assessment covering the Company's load forecast, status of existing resources, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 5).
- A profile of the resource options considered for addressing future capacity deficits (Chapter 6).
- A description of the IRP modeling, risk analysis, and portfolio performance ranking processes (Chapter 7).
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio (Chapter 8)
- An IRP action plan linking the Company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource risks (Chapter 9)
- PacifiCorp's transmission expansion action plan, focusing on the Energy Gateway Transmission project (Chapter 10)

The IRP appendices, included as a separate volume, comprise detailed IRP modeling results (Appendices A and B), fulfillment of IRP regulatory compliance requirements, (Appendix C), the public input process (Appendix D), additional load forecast information (Appendix E), the results of PacifiCorp's wind integration cost study (Appendix F), energy efficiency program avoided cost estimates (Appendix G), and additional load and resource balance information pertaining to the Lake Side II combined-cycle gas plant (Appendix H).

THE ROLE OF PACIFICORP'S INTEGRATED RESOURCE PLANNING

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[4] The main role of the IRP is to serve as a roadmap for determining and implementing the Company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting Request for Proposals (RFP) bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

ALIGNMENT OF PACIFICORP'S IRP AND BUSINESS PLANNING PROCESSES

Alignment Strategy Overview

The alignment strategy consists of the following four elements:

- **Scheduling synchronization** – PacifiCorp modified its IRP preparation schedule to accommodate business plan preparation beginning in March 2008 and ending in late November 2008, culminating with plan approval in mid-December 2008 by the MidAmerican Energy Holdings Company (MEHC) board of directors.

- **Input assumption synchronization** – The IRP models are updated on a real-time basis as changes to business plan assumptions occur. These changes include, but are not limited to, revised load forecasts, forward price curves, resource costs, and environmental compliance policy assumptions. Public stakeholders are updated on major changes to input assumptions.

- **IRP modeling support for business plan development** – For each business planning scenario[5], PacifiCorp conducts IRP modeling to produce a resource portfolio for capital budgeting

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

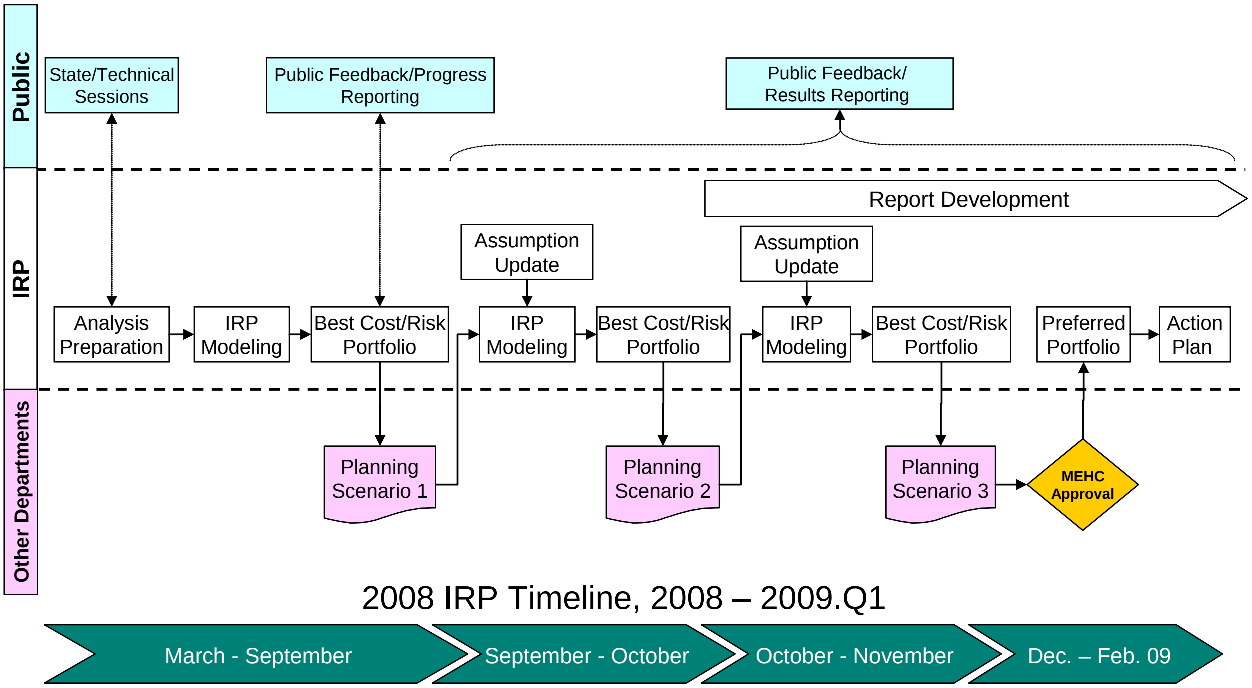
[5] A business planning scenario represents a unique set of assumptions for producing a planning outcome and associated financial results for a 10-year period. The business planning schedule accounts for preparation of three scenarios. Typically, the goal of each successive scenario is to (1) improve customer service and operational and financial results by optimizing operational expenditures and capital investments in accordance with the Company's business strategy, and (2) incorporate updated assumptions into the business planning process. Each planning scenario requires a complete processing cycle, including input collection and aggregation, tax estimation, cash-flow optimization through debt issuance and equity investment, quality assurance, and management review.

The key product for each planning scenario is a documentation package that describes the planning assumptions and contains a set of pro-forma financial statements conveying the financial impacts of the planning assumptions. PacifiCorp submits each planning scenario to MidAmerican Energy Holdings Company for review and approval on pre-established dates. At the end of the year, after the business plan receives MEHC board approval, high-level business planning information is provided in filings as required by state and federal regulations. Certain information and rate impact analysis by the corporate finance department. In an iterative process, resource constraints are applied to the portfolio optimization modeling to ensure that subsequent portfolios are deemed affordable and financeable by senior management.

- **Public process** – Through public meetings or other communication methods, the Company's IRP public participants are updated on significant business planning events. The relationship between the business plan and IRP preferred portfolios are documented in the IRP action plan.

Figure 2.1 is a process flow diagram that shows the relationship between IRP activities, business plan preparation, and the public process originally envisioned for the 2008 IRP development cycle.

Figure 2.1 – IRP/Business Plan Process Flow



Planning Process Alignment Challenges

A key challenge for the alignment was to reconcile the different planning perspectives associated with the two-year IRP development cycle and the annual corporate business planning cycle. As mentioned above, the IRP is a strategic planning roadmap focused on the long-term costs and risks of resource portfolios, accounting for uncertainty. In contrast, PacifiCorp's business plan focuses on maintaining a strong financial position while ensuring customer's generation needs are met economically given the expected operating environment. Central to this business planning goal is an emphasis on acquiring and managing the Company's assets to smooth the cost

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is also released on a confidential basis to various rating agencies and in certain regulatory dockets or other venues where necessary.

impacts for customers. Successful alignment of the two planning processes thus entails balancing these perspectives as resource decisions are made.

Another key challenge for the planning process alignment was to accommodate the preparation timing differences and analytical requirements for the two planning processes. The 10-year business plan is an annual process that entails frequent input assumption updates and preparation of multiple versions of the plan for internal prudence reviews. On the other hand, the IRP is a biennial planning process requiring extensive upfront model preparation, a public input process, and completion of specific analytical tasks cited in the state's IRP standards and guidelines and IRP acknowledgment orders. Meshing the planning processes entails significantly more departmental coordination, along with an acceleration of the IRP modeling workflow to start portfolio development two to three months earlier than is typically done for the IRP.

A final key challenge was to provide modeling support for both the IRP and business plan while at the same time implementing major modeling enhancements. These enhancements included (1) unbundling Class 2 demand-side management programs (energy efficiency) from the load forecasts and instituting a Class 2 DSM supply curve modeling approach, (2) expansion of resource options to include wind with different resource qualities, additional renewable technologies, energy storage, nuclear, distributed generation, fuel cells, and additional front office transaction product types, (3) improvements in modeling renewable portfolio standard (RPS) requirements, (4) computer and network infrastructure upgrades, and (5) a major upgrade of the Planning and Risk production cost model.

Given these challenges, the expectation was that the alignment would be conducted over a two-year span.

Alignment Strategy Progress

PacifiCorp successfully implemented all the planned IRP modeling system improvements, and maintained input consistency with business plan assumptions throughout the planning cycle. Importantly, the business plan benefited from implementation of the DSM class 2 supply curves, providing for the first time energy efficiency program targets based on integrated resource portfolio modeling with these resource options included. PacifiCorp also successfully provided an optimized resource portfolio for each business planning scenario.

However, two alignment strategy objectives were not met. For the business plan, PacifiCorp originally intended to conduct alternative portfolio development with different input assumptions (basically a subset of the input scenarios defined for the IRP), and run Monte Carlo production cost simulations to compare portfolio stochastic costs and risks. Additionally, public reporting goals on the progress of business plan preparation could not be accommodated in the schedule. There were two reasons for not meeting these objectives. First, business plan portfolio optimization modeling required frequent updates in reaction to volatile energy markets, the financial market crisis, a deteriorating load growth outlook, and continued resource cost increases. This caused a delay of the start of IRP modeling, while the turnaround time for business plan modeling precluded establishment of a meaningful public comment and response process. Second, the modeling enhancements and system upgrades—particularly for the Planning and Risk model—took longer than expected.

As a consequence of the IRP modeling delay, the business plan was approved by the MEHC board of directors in December 2008—prior to the completion of IRP modeling and selection of the 2008 IRP preferred portfolio. In accordance with the alignment strategy, the major resource changes relative to the business plan were analyzed for financial and ratepayer impact by the PacifiCorp Energy Finance Department. Major differences between the business plan resources and the 2008 IRP preferred portfolio are described in Chapters 8 and 9.

PUBLIC PROCESS

The IRP standards and guidelines for certain states require PacifiCorp have a public process allowing stakeholder involvement in all phases of plan development. The Company held 17 public meetings/conference calls during 2008 and early 2009 designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public meetings/conferences and major agenda items covered.

Table 2.1 – 2008 IRP Public Meetings

Meeting Type	Date	Main Agenda Items
General Meeting	2/29/2008	2008 IRP modeling plan, business planning process, 2007 IRP Update
State Stakeholder Input	4/9/2008	Utah stakeholder comments
State Stakeholder Input	4/10/2008	Wyoming stakeholder comments
State Stakeholder Input	4/21/2008	Oregon and California stakeholder comments
State Stakeholder Input	4/22/2008	Washington stakeholder comments
State Stakeholder Input	4/23/2008	Idaho stakeholder comments
State Stakeholder Input	5/14/2008	Utah stakeholder comments
General Meeting	5/22/2008	Input scenario ("case") definitions, resource characterization
Workshop	5/23/2008	CO_2 costs and modeling, EPRI CO_2 study results
Workshop	6/26/2008	Load forecasting methodology, preliminary load forecast
General Meeting	11/12/2008	Load forecast update, IRP/Business plan alignment, IRP status (conf. call)
General Meeting	12/18/2008	Load forecast update, portfolio development results, load & resource balance
General Meeting	1/7/2009	Repeat of 12/18/2008 agenda for Washington and Idaho stakeholders
General Meeting	2/2/2009	Stochastic modeling results, portfolio performance, preferred portfolio
General Meeting	3/11/2009	IRP status and state commission filing update (conference call)
State Stakeholder	3/19/2009	Utah state commission filing schedule for IRP (conference call)

New for this IRP was a series of state stakeholder dialogue sessions conducted from April through May 2008. The purpose of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. This change in public process was intended to enhance interaction with stakeholders early on in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during general public meetings.

Appendix D, in the separate appendix volume, provides more details concerning the public meeting process and individual meetings.

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

MIDAMERICAN ENERGY HOLDINGS COMPANY IRP COMMITMENTS

MEHC and PacifiCorp committed to continue to produce IRPs according to the schedule and various state commission rules and orders at the time the transaction was in process. Other commitments were made to (1) encourage stakeholders to participate in the integrated resource planning process and consider transmission upgrades, (2) develop a plan to achieve renewable resource commitments, (3) consider utilization of advanced coal-fuel technology such as IGCC technology when adding coal-fueled generation, (4) conduct a market potential study of additional demand-side management and energy efficiency opportunities, (5) evaluate expansion of the Blundell Geothermal resource, and (6) include utility "own/operate" resources as a benchmark in future request for proposals. The Transaction Commitments Annual Report for 2009 is in progress and due to be filed with each Commission on Friday, May 29, 2009.

3. THE PLANNING ENVIRONMENT

INTRODUCTION

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

A key resource planning consideration has been the faltering U.S. economy and tightening of credit markets. Changing economic circumstances have required the Company to continuously re-evaluate and adjust load growth and market price expectations throughout this planning cycle, a process mentioned in the previous chapter in the context of 2009 business plan preparation. For capital expenditure planning, the Company's challenge has been to minimize customer rate impacts in light of a substantial capital spending requirement needed to address customer load growth, support government environmental and energy policies, and maintain transmission grid reliability. To address this challenge, PacifiCorp is scrutinizing capital projects for cost reductions or deferrals that make economic sense in today's market environment. Along these lines, the Company recently decided to seek more cost-effective alternatives to the planned Lake Side II combined-cycle gas plant project in Utah. The implications of this resource decision for the IRP are addressed in this chapter.

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

On the government policy and regulatory front, the largest issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the Company's greenhouse gas emissions mitigation strategy, as well as an overview of the Electric Power Research Institute's study on carbon dioxide price impacts on western power markets, follows. This chapter also reviews the significant policy developments for currently-regulated pollutants

Other topics covered in this chapter include the Energy Independence and Security Act of 2007, the status of renewable portfolio standards, hydroelectric licensing, and resource procurement activities.

IMPACT OF THE 2012 COMBINED-CYCLE GAS PLANT PROJECT TERMINATION

In February 2009, PacifiCorp decided to terminate the construction contract for the Lake Side II combined-cycle plant, which was planned to be in commercial operation by the summer of 2012. The decision to seek other resource alternatives was driven by the worsening recessionary environment, declines in load growth, continued declines in forward electricity and gas prices, the outlook for future plant construction costs, and additional transmission import capability into Utah confirmed with recently completed transmission studies. The construction termination decision occurred after initial selection of the 2008 IRP preferred portfolio, but before finalization of the IRP document and preparation of the IRP action plan. Consequently, PacifiCorp decided to conduct additional portfolio analysis to determine the impacts of excluding Lake Side II as a planned resource in 2012, and then update the preferred portfolio and develop the action plan accordingly. This analysis consisted of the following five steps:

- Revise the load and resource balance to reflect the absence of the Lake Side II CCCT plant in 2012 (shown in Chapter 5).

- Update the IRP models with new transmission and market purchase availability information that can facilitate cost-effective alternatives to a single large 2012 resource addition (described in Chapter 6).

- Use the Company's capacity expansion optimization model to develop a set of alternative portfolios without the Lake Side II plant, applying the same input scenarios ("cases") that yielded the top-performing portfolios in PacifiCorp's original portfolio analysis. (This portfolio development is summarized in Chapter 8.)

- Conduct stochastic Monte Carlo production cost simulation of the alternative portfolios, and determine the new preferred portfolio with the support of the portfolio preference scoring methodology adopted for this IRP. (The portfolio performance evaluation is described in Chapter 8.)

- Include the findings of the portfolio analysis in the IRP action plan and supporting acquisition path analysis.

WHOLESALE ELECTRICITY MARKETS

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

PacifiCorp participates in the wholesale market in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to efficiently match delivery patterns to the profile of customer demand. The market is not without its risks, as the experience of the 2000-2001 market crisis, followed by the rapid price escalation during the first half of 2008 and subsequent demand destruction and rapid price declines in the second half of 2008, have underscored.

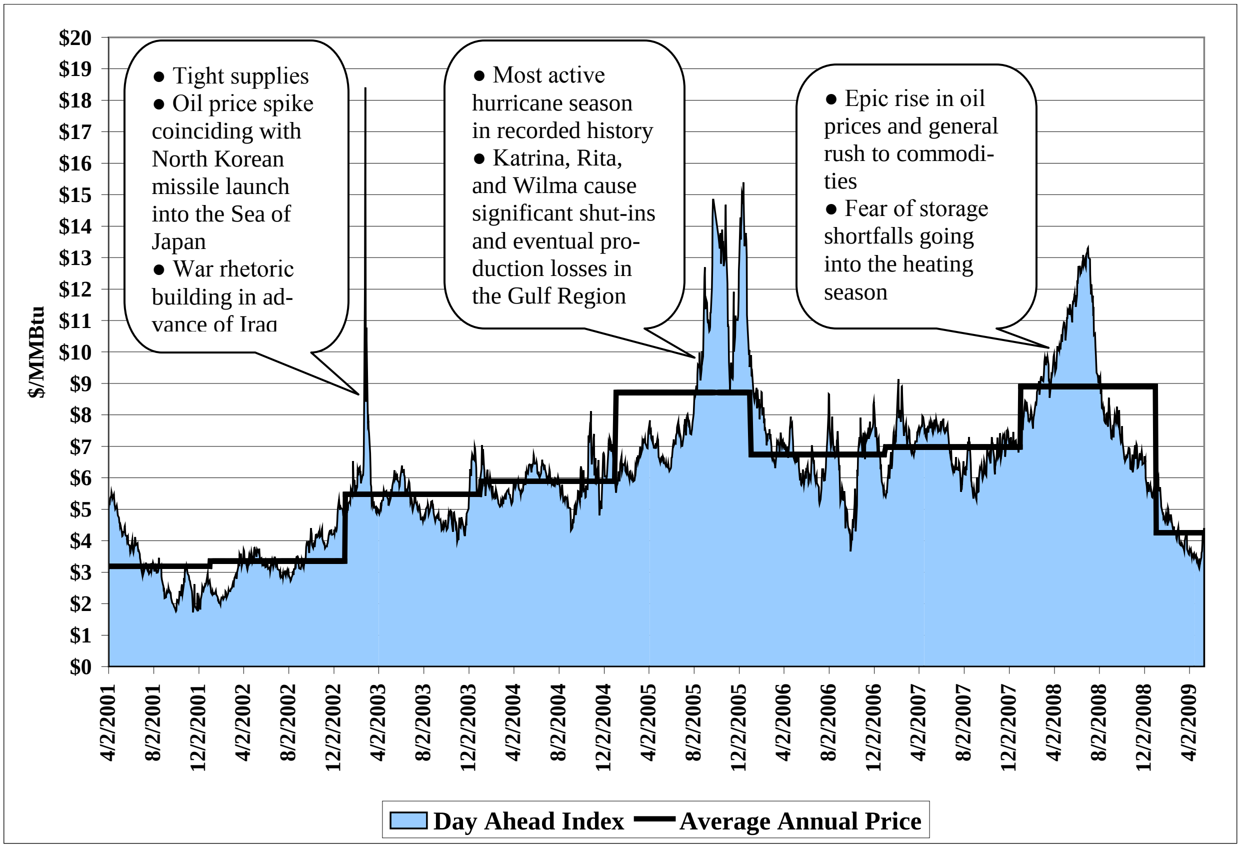
As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, the Western Electricity Coordinating Council (WECC) publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. The latest WECC power supply assessment, published in November 2008, indicates that the Basin and Rockies sub-regions will be resource deficit, after accounting for reserves, by 2011. (It should be noted that this assessment does not account for the recent recessionary impacts on load growth and various utilities' resource plans.)

There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices. Given the increased role of natural gas-fired generation, gas prices have become a critical determinant in establishing western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on this IRP is the prospect of future green house gas policy. A broad landscape of federal, regional, and state proposals aiming to curb green house gas emissions continues to widen the range of plausible future energy costs, and consequently, future electricity prices. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

Natural Gas Uncertainty

Over the last eight years, North American natural gas markets have demonstrated exceptional price escalation and volatility. Figure 3.1 shows historical day-ahead prices at the Henry Hub benchmark from April 2, 2002 through February 3, 2009. Over this period, day-ahead gas prices settled at a low of $1.72 per MMBtu on November 16, 2001 and at a high of $18.41 per MMBtu on February 25, 2003. During the fall and early winter of 2005, prices breached $15 per MMBtu after a wave of hurricanes devastated the gulf region in what turned out to be the most active hurricane season in recorded history. More recently, prices topped $13 per MMBtu in the summer of 2008 when oil prices began their epic climb above $140 per barrel. During this period, the natural gas market was also concerned that declining imports and slow growth in domestic production would create a storage shortfall going into the heating season. However, as the year progressed, it became increasingly evident that gains in unconventional supply was growing at an unprecedented pace, quelling fears of an unbalanced market. At the same time, the market began accounting for sharp declines in demand as the financial crisis evolved into a full-scale global recession. Consequently, prices retreated just as quickly as they rose.

Figure 3.1 – Henry Hub Day-ahead Natural Gas Price History



Source: IntercontinentalExchange (ICE), Over the Counter Day-ahead Index

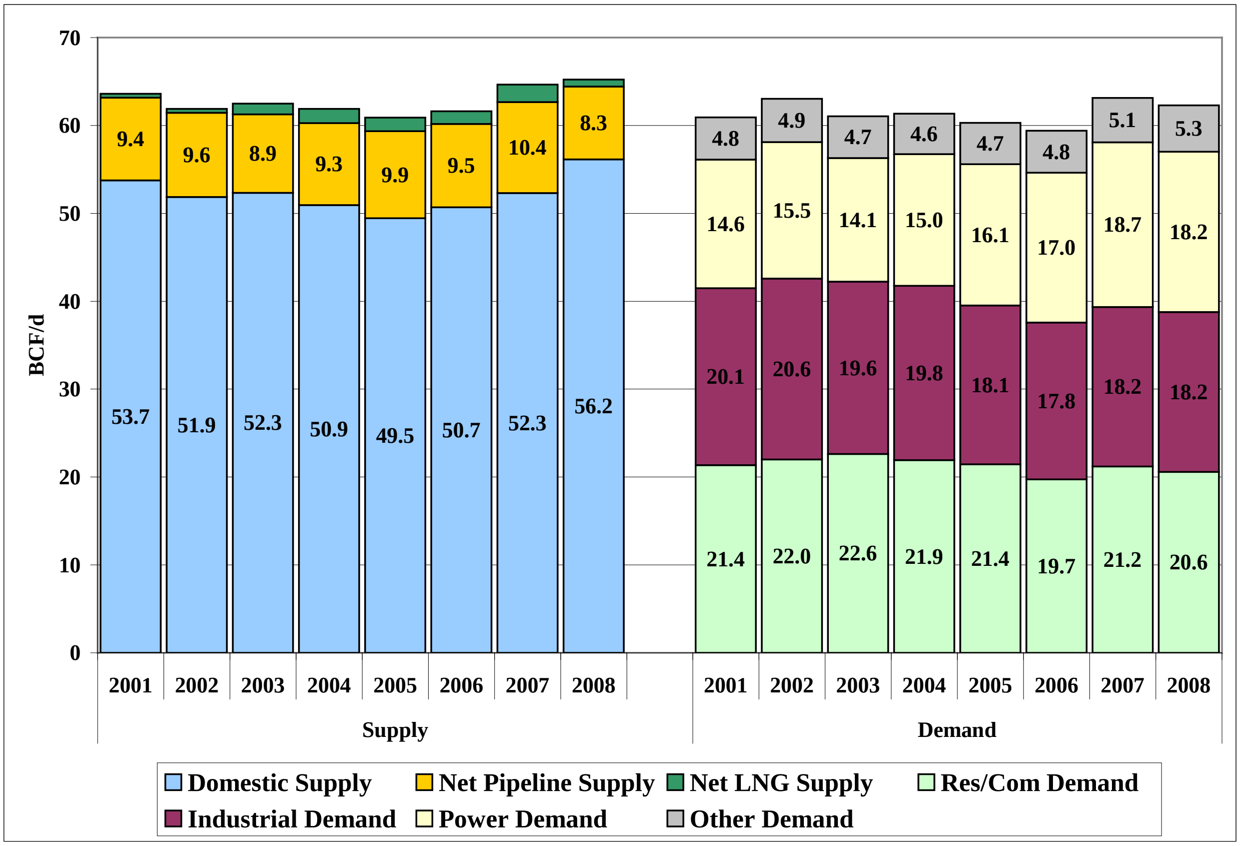
Beyond the geopolitical, extreme weather, and economic events that spawned some rather spectacular highs in the recent past, natural gas prices have exhibited an underlying upward trend from approximately $3 per MMBtu in 2002 to nearly $7 per MMBtu by 2007. Over much of this period, declining volumes from conventional, mature producing regions largely offset growth from unconventional resources. Figure 3.2 shows a breakdown of U.S. supply alongside natural gas demand by end-use sector.

Total supply, led by declines in domestic production, dropped steadily from 2001 through 2005. While total supply posted modest gains in 2006 and 2007, domestic production remained below the levels recorded in 2001. On the demand side, substantial expansion of gas-fired generating resources had more than offset declines in industrial demand for natural gas. This shift reduced the amount of industrial demand that is most price-elastic and increased inelastic generation demand. With higher finding and development costs of unconventional resources, the price level necessary to stimulate such marginal supply had grown. Until the recent economic downturn, substantial oil price escalation also supported higher natural gas prices, lifting the price of marginally competitive gas substitutes and the value of natural gas liquids.

Combined, the above factors contributed to a pronounced supply/demand imbalance in North American natural gas markets, raising prices sufficiently high to discourage marginal demand and, at times, attracting imports from an equally tight global market. This imbalance also made

North American markets more susceptible to upset from weather and other event shocks such as those discussed earlier.

Figure 3.2 – U.S. Natural Gas Balance History



Source: U.S. Department of Energy, Energy Information Administration

The supply/demand balance began to shift in 2007 and 2008 thanks to an unprecedented and unexpected burst of growth from unconventional domestic supplies across the lower 48 states. With rapid advancements in horizontal drilling and hydraulic fracturing technologies, producers began drilling in geologic formations such as shale. Some of the most prominent contributors to the rapid growth in unconventional natural gas production have been the Barnett Shale located beneath the city of Forth Worth, Texas and the Woodford Shale located in Oklahoma. Strong growth also continued in the Rocky Mountain region.

Looking forward, many forecasters have been expecting that a gradual restoration of improved supply/demand balance would be achieved largely with growth in liquefied natural gas (LNG) imports. Indeed, there has been tremendous growth in global liquefaction facilities located in major producing regions, and additional projects are expected to come online in 2009 and 2010. Concurrently, U.S. regasification capacity has grown to overbuild proportions. As of the end of 2008 U.S. regasification capacity was 4.7 times larger than the 1.98 BCF/d of LNG imports logged in 2007, and additional capacity is scheduled to go online in 2009 and 2010. Even with substantial gains in global LNG supplies and in domestic regasification capacity, the North

American market has not been able to consistently lure shipments from Asian and European markets, where gas prices are more directly linked to the price of oil.

With the recent expansion of unconventional production and the evolution of global LNG markets, many forecasters and market participants are beginning to reassess how mid- to long-term markets will balance. For example, the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) from 2007 forecasted that LNG imports would top 8 BCF/d by 2015. In the early look of AEO 2009 released in December 2008, the EIA expects 2015 LNG imports to total 3.4 BCF/d – just 41 percent of the LNG imports projected two years earlier. Beyond the near-term, where demand is being depressed by the current economic downturn, it is increasingly believed that unconventional supplies from North America are poised to meet incremental demand upon economic recovery. Under such a scenario, North American gas prices would remain decoupled from the global LNG market, and consequently decoupled from Asian and European natural gas markets, which are more heavily influenced by the price of oil.

Several factors contribute to a wide range of price uncertainty in the mid- to long-term. On the downside, technological advancements underlying the recent expansion of unconventional supplies opens the door to tremendous growth potential in both production and proven reserves from shale formations across North America. A number of shale formations outside of the Barnett and Woodford have already started to show upside potential. A sign of the times, the proposed Kitimat regasification terminal in British Columbia, Canada announced that the project was being redesigned as a liquefaction terminal apparently due to interest in the Horn River and Motney shale formations within the province. On the upside, the next generation of unconventional supplies may prove to be more difficult to extract, raising costs, and consequently, raising prices. Moreover, a concerted U.S. policy effort to shift the transportation sector away from oil toward natural gas has potential to significantly increase demand, and thus natural gas prices.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices. Although Rocky Mountain region production, among the fastest growing in North America, has caused prices at the Opal and Cheyenne hubs to transact at a discount to the Henry Hub benchmark in recent years, major pipeline expansions to the mid-west and east coupled with further pipeline expansion plans to the west are expected to maintain market price correlations going forward. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to other hubs in the region. This has been driven in large part by declines in Canadian natural gas production and reduced imports into the U.S. In the near-term, Canadian imports from British Columbia are expected to remain below historical levels lending support for basis differentials in the region; however, in the mid- to long-term, production potential from regional shale formations will have the opportunity to soften the Sumas basis.

Greenhouse Gas Policy Uncertainty

There is a wide range of policy proposals to limit greenhouse gas emissions within the U.S. economy. At the federal level, Senators Bingaman and Specter sponsored the Low Carbon Economy Act of 2007 (the Bingaman Bill), and more recently, Senators Lieberman and Warner introduced the Climate Security Act of 2008 (the Lieberman Warner Bill), while Representatives Waxman and Markey introduced the American Clean Energy and Security Act of 2009 (H.R.

2454). While it remains unclear what types of federal proposals will be debated going forward, there have been clear signals that the Obama administration has more of an appetite than the previous administration to address the climate change issue. At the state and regional level, the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program to restrict carbon dioxide emissions in Northeastern and Mid-Atlantic states, took affect in 2008. A similar approach is being explored in the Midwest under the Midwest Greenhouse Gas Accord. In the West, the Western Climate Initiative continues its work toward establishing rules for its own cap-and-trade program. Additional details on greenhouse gas policy developments are discussed later in this chapter.

As the policy debate continues, a cloud of uncertainty continues to hang over the electric sector, with substantial implications for investment decisions and wholesale electricity markets. There are a host of uncertainties stemming from the policy debate:

- If emission limits are put in place, will they cover the entire U.S. economy or will they target specific sectors?
- Will emission reductions be achieved through a cap-and-trade approach, through a carbon tax, or some combination of the two?
- What role, if any, will domestic and international offsets play in achieving emission reductions in the U.S.?
- Will emission reductions be achieved through a national program that preempts state and regional initiatives, will there be a more Balkanized approach, or will there be a national program layered on top of state and regional initiatives?
- How will renewable portfolio standards be coordinated or integrated with emission reduction regulations?

Regardless of how the policy debate unfolds, one thing remains clear. If limits are placed on greenhouse gas emissions, it is highly probable that the electric sector will be required to reduce emissions, and these emission reductions will come with a cost. Whether the costs are directly assessed in the form of a tax or are indicative of opportunity costs monetized in a market developed under a cap-and-trade program, all else equal, the cost to produce electricity will increase, and wholesale prices will respond. The projected cost of greenhouse gas emission reductions are intrinsically tied to policy details and vary considerably. Even for a given policy, there are a wide range of future cost estimates driven by long-term assumptions such as electricity demand, technological advancements, and varying interpretations of policy implementation rules. For example, in the December 17, 2008 auction for RGGI carbon dioxide emission allowances, prices cleared at $3.38/ton. In contrast, the Energy Information Administration's (EIA) analysis of the Lieberman Warner Bill projected nominal allowance prices by 2030 ranging from nearly $35/ton to approximately $275/ton, while the U.S. Environmental Protection Agency's preliminary study of the Waxman-Markey Bill cited a scenario CO_2 cost range per metric ton of $17 to $33 by 2020.[6]

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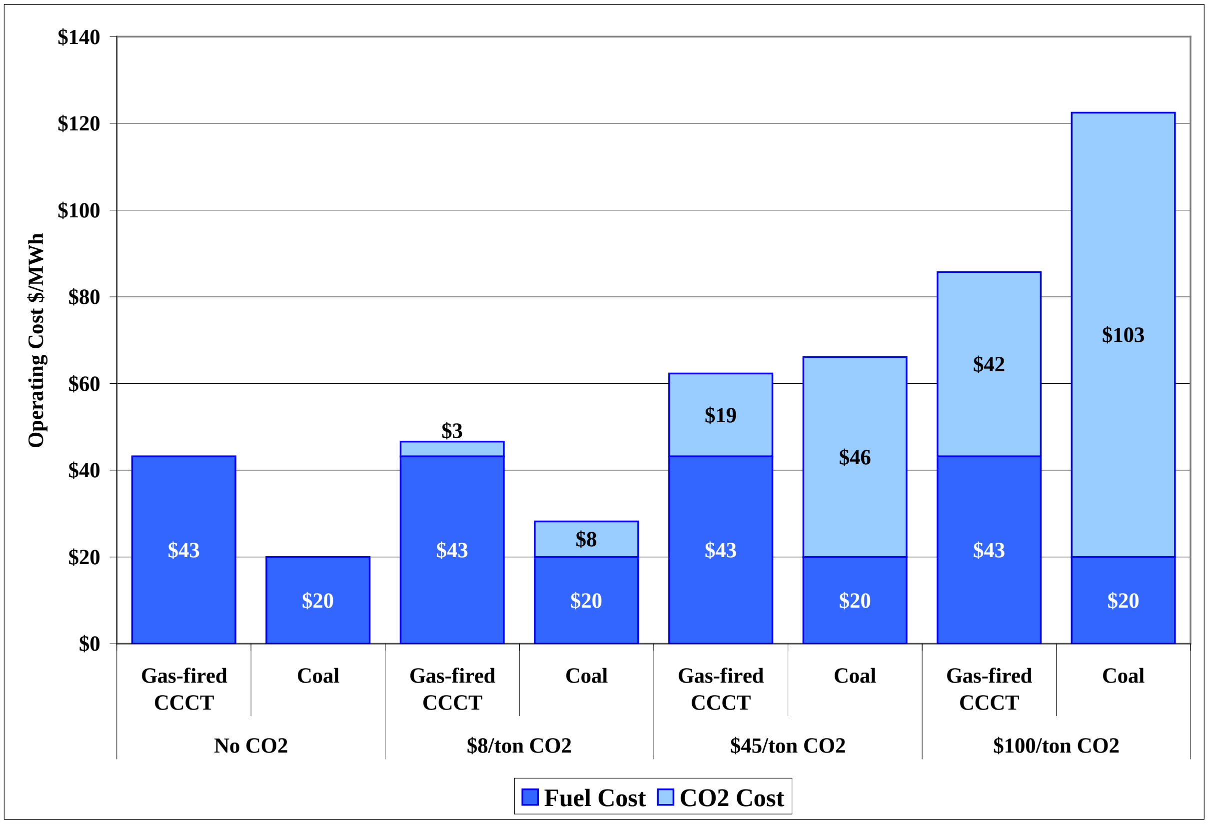
[6] A discussion draft of the EPA study is available at: http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf. The discussion draft notes that are remaining legislative uncertainties that could significantly change study results, and that the study represents limited coverage of bill provisions.

When a cost is placed on greenhouse gas emissions, it effectively becomes an additional variable cost facing an electric generator, and in much the same way that fuel costs affect plant dispatch decisions, emission costs influence how a plant operates. Because electric generators burn different types of fuel, have varying levels of efficiency, and are bound by different operational limitations, the impact of incremental green house gas costs varies across different types of technologies. To understand how green house gas emission costs will discriminately affect electricity markets, one can consider a simplified representation of the power system – a system that includes two types of resources: (1) a coal-fired plant, and (2) a gas-fired combined cycle plant.

Coal-fired assets, with limited operational flexibility and access to relatively low cost fuel, tend run around the clock. This type of base load capacity is often used to satisfy demand even when it is quite low. On the other hand, while natural gas-fired combined cycle assets typically have an efficiency advantage relative to a coal plant, they are often faced with higher fuel costs and have more operational flexibility to alter their production in response to changing conditions. Consequently, this type of resource is often ramped up as demand increases and ramped down when demand falls. In this way, coal resources are more likely to establish off-peak electricity prices than on-peak electricity prices. Conversely, natural-gas fired capacity is more likely to set electricity prices during peak demand periods. When green house gas emission costs are introduced, this basic trend can be altered.

Figure 3.3 shows illustrative dispatch costs for a coal plant and a natural-gas fired combined cycle plant at different carbon dioxide pricing points – no cost, $8/ton, $45/ton, and $100/ton. The coal plant is assumed to have a heat rate of 10,000 Btu/kWh and is faced with fuel prices of $2 per MMBtu. The gas-fired plant is assumed to have a heat rate of 7,200 Btu/kWh and is faced with a fuel price of $6 per MMBtu. Without any incremental carbon cost, Figure 3.3 shows a decided cost advantage for the coal asset. While the operating cost advantage for a coal plant is maintained when carbon costs are at $8/ton, the cost advantage begins to narrow. At $45/ton, both technologies are on nearly equal footing, with a slight advantage now in favor of the gas-fired combined cycle asset. Finally, at $100/ton, the cost advantage is reversed and is now decidedly in favor of the gas-fired plant.

Figure 3.3 – Green House Gas Cost Implications for Electric Generators



From the simplified example in Figure 3.3, one can appreciate how green house gas costs might affect wholesale electricity markets. With no carbon costs, the marginal unit is the gas-fired combined cycle, which, in this example, would support electricity prices somewhere north of $43 per MWh. When carbon costs climb to $100/ton, the marginal coal unit from this example would support wholesale electricity prices north of $120 per MWh. Of course, in reality, the power system is more complex than this simplified representation. There are additional resources—hydro power, nuclear, gas-fired peaking plants, and renewables—competing in the market. Moreover, there are other interactions that are likely to take place as greenhouse gas costs escalate and operational changes are implemented accordingly. For example, as carbon costs rise, it is possible that natural gas demand would increase, exerting upward pressure on gas prices. Similarly, even though natural fired capacity has a cost advantage relative to coal at higher carbon costs, coal does not have the operational flexibility to ramp output up and down with swings in demand. Regardless, given the range of potential policy outcomes, it is evident that the implications for greenhouse gas costs in the wholesale electricity market are highly variable and highly uncertain.

There are additional implications for the wholesale electricity market that extend beyond the direct cost impacts discussed above. For example, if carbon costs are exceptionally high and/or particularly volatile, the number of parties willing and or able to transact may begin to dwindle, and it is possible that depth and liquidity in the forward markets may suffer. Similarly, if a more Balkanized policy landscape materializes, there is a risk that transaction costs among market participants would increase. In yet another scenario, it is conceivable that poorly coordinated implementation rules among multiple programs might cause some market participants to retreat from specific trading hubs that are caught in a jurisdictional web of rules and ambiguity.

CURRENTLY REGULATED EMISSIONS

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

Ozone

Final action on the revisions to the National Ambient Air Quality Standards for ozone was completed on March 12, 2008. The EPA announced that the National Ambient Air Quality Standards for primary and secondary ground-level ozone would be significantly strengthened. The primary ozone standard, which is designed to protect public health and the secondary standard, which is designed to protect public welfare (including crops, vegetation, wildlife, buildings, national monuments, and visibility) from the negative effects of ozone, were both reduced to 0.075 parts per million.

The new standards took effect on May 27, 2008. States have until March 12, 2009, to make recommendations to the EPA as to whether an area should be designated attainment (meeting the standard), nonattainment (not meeting the standard) or unclassifiable (not enough information to make a decision). The EPA must promulgate its attainment/nonattainment designations by March 12, 2010, unless a one-year extension is granted because of insufficient information. By March 12, 2011, or one year after the EPA promulgates its designations, states will be required to submit their state implementation plans detailing how they will meet the new standards. A number of rules have been issued by the EPA that will potentially help states make progress toward meeting the revised ozone standards, including the Clean Air Interstate Rule to reduce ozone forming emissions from power plants in the eastern United States, and the Clean Diesel Program to reduce emissions from highway, non-road and stationary diesel engines nationwide.

Immediately following the promulgation of the strengthened ozone standards, multiple lawsuits were filed against the EPA. New York and thirteen other states sued the Environmental Protection Agency on May 27, 2008, demanding stricter air quality standards for ozone. New York was joined in the lawsuit by California, Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New Mexico, Oregon, the Pennsylvania Department of Environmental Protection, and Rhode Island. New York City and the District of Columbia also joined in the lawsuit. A coalition of environmental and public health advocates also filed a lawsuit against the Environmental Protection Agency on May 27, 2008, in a bid to strengthen the ozone standard. Meanwhile, Mississippi and a coalition of industry trade groups filed separate petitions for review May 23, 2008, and May 27, 2008, respectively, in the District of Columbia Circuit Court of Appeals, arguing the new standards are too strict.

After EPA tightened the 8-hour standard to 0.075 parts per million, several Utah counties located along the Wasatch Front were put in jeopardy of being designated non-attainment. Utah is now using certified monitored ozone data from 2005–2007 to determine specifically which areas need to be designated non-attainment of the 0.075 parts per million standard. The state must submit a recommendation to the EPA by March 2009. The EPA will then either accept or modify the state's recommendation, based on certified data from 2006-2008, and issue a final designation by March 2010. In Utah, ozone is principally a summer time problem when temperatures are high and daylight hours are long, but it may have implications to wintertime particulate problems as well. It is a mix of chemicals emitted mainly from vehicle tailpipes, diesel engines and industrial smokestacks. The Utah Department of Environmental Quality has indicated that its anticipated control strategy would focus on transportation, including tightening regulations for gasoline stations, and possibly consumer products, and certain industrial emissions.

Currently, with the exception of the Gadsby power plant, all of PacifiCorp Energy's operating fossil-fueled facilities are located in areas that are in attainment with the ozone National Ambient Air Quality Standards. The Gadsby plant is a gas fired facility located in downtown Salt Lake City, Salt Lake County, Utah. Salt Lake County is currently a non-attainment area for ozone. The Utah Department of Environmental Quality has stated that at this time, no coal- or natural gas-fueled power plants will be the subject of new control strategies.

Particulate Matter

On October 17, 2006, the EPA issued new National Ambient Air Quality Standards for particle pollution. The final standards addressed two categories of particle pollution: fine particles ($PM_{2.5}$), which are 2.5 micrometers in diameter and smaller; and inhalable coarse particles (PM_{10}), which are smaller than 10 micrometers. The Environmental Protection Agency strengthened the 24-hour fine particle standard from the 1997 level of 65 micrograms per cubic meter to 35 micrograms per cubic meter, and retained the current annual fine particle standard at 15 micrograms per cubic meter. The Agency also retained the existing national 24-hour PM_{10} standard of 150 micrograms per cubic meter and revoked the annual PM_{10} standard.

The new federal standards has put Utah's Wasatch Front – including all of Salt Lake and Davis Counties and portions of Weber, Box Elder and Toole counties – into a "non-attainment" status – as well as the low-lying portions of Utah and Cache Counties. Utah has until 2012 to draft a plan to EPA on how it will achieve compliance with the fine particulate NAAQS. According to the Utah Department of Environmental Quality, much of the particulate pollution is attributable to emissions from automobiles. Utah's monitoring suggests a seasonal problem characterized by episodic periods of very high concentrations of fine particulate that consists mostly of secondary particulate. The formation of these secondary particles is driven by winter-time temperature inversions which trap air in urbanized valleys. The mix of emissions associated with the urbanized areas reacts very quickly under these conditions to produce spikes in the concentration of fine particulate. Under these conditions, the observed concentrations are fairly uniform throughout the entire urbanized area. This underscores the association of urban areas with a mix of emissions that inherently reacts under these conditions to form PM2.5, and helps to define PM2.5 somewhat as an "urban" pollutant. All of this serves to highlight the distinction between urban and rural areas. Much of this phenomenon is also due to the fact that population is generally located within the lowland valley areas in which air is easily trapped by a temperature inversion. In other words, it is not enough to simply have an urban area with an urban mix of emissions; there must also be a barrier to dispersion under these conditions, which allows PM2.5 concentrations to build up over a period of several days and reach concentrations that exceed the NAAQS. This characterization of Utah's difficulties with fine particulate has shaped the State's approach to making the area designations.

Currently, with the exception of the Gadsby power plant, all of PacifiCorp's operating fossil-fueled facilities are located in areas that are in attainment with the fine particulate National Ambient Air Quality Standard. The Gadsby plant is a gas-fired facility located in downtown Salt Lake City, Salt Lake County, Utah. Salt Lake County has been proposed as a non-attainment area for fine particulate matter. The Utah Department of Environmental Quality has stated that at this time, no coal- or natural gas-fueled power plants will be the subject of new fine particulate matter control strategies.

Regional Haze

Within existing law, EPA's Regional Haze Rule and the related efforts of the Western Regional Air Partnership will require nitrogen oxide, sulfur dioxide, and particulate matter emissions reductions to improve visibility in scenic areas. Arizona, New Mexico, Oregon, Utah and Wyoming originally submitted state implementation plans addressing regional haze based upon 40 CFR 51.309, focusing on the reduction of sulfur dioxide emissions from large industrial sources located throughout the West. Regional Sulfur Dioxide Emissions and Milestone Reports, one of the requirements of the 309 state implementation plan, are submitted each year. The reports determine whether sulfur dioxide emitted by large industrial sources exceeds the sulfur dioxide emission milestones set in the states' Regional Haze state implementation plans. The sulfur dioxide milestones take into account emissions reductions either achieved or expected to be achieved from the installation of Best Available Retrofit Technology on eligible units.

The State of Wyoming submitted revisions to the 2003 309 Regional Haze state implementation plan to EPA Region 8 on November 24, 2008 and will now focus on impairment caused by sources of nitrogen oxides and particulate matter. Work on this phase of regional haze planning is underway with a draft SIP expected in the spring of 2009. Utah similarly adopted revisions to its regional haze state implementation plan on September 3, 2008, which became effective and enforceable in Utah on November 10, 2008. The package of materials was submitted to the EPA on September 18, 2008 and will become federally enforceable after EPA approves them.

Additionally, administrative rulemakings by EPA, including the Clean Air Interstate Rule will require significant reductions in emissions from electrical generating units that directly impact the national market for sulfur dioxide allowances. Compliance costs associated with anticipated future emissions reductions will largely depend on the levels of required reductions, the allowed compliance mechanisms, and the compliance time frame.

Mercury

In March 2005, the EPA released the final Clean Air Mercury Rule ("CAMR"), a two-phase program that would have utilized a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons. The CAMR required initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70 percent by 2018. The individual states in which PacifiCorp operates facilities regulated under the CAMR submitted state implementation plans reflecting their regulations relating to state mercury control programs. On February 8, 2008, a three-judge panel of the United States Court of Appeals for the District of Columbia Circuit held that the EPA improperly removed electricity generating units from Section 112 of the Clean Air Act and, thus, that the CAMR was improperly promulgated under Section 111 of the Clean Air Act. The court vacated the CAMR's new source performance standards and remanded the matter to the EPA for reconsideration. On March 24, 2008, the EPA filed for rehearing of the decision of the three-judge panel by the full court; rehearing was denied in May 2008. On September 17, 2008, the Utility Air Regulatory Group petitioned the United States Supreme Court for a writ of certiorari to review the United States Court of Appeals for the District of Columbia Circuit's February 8, 2008 decision overturning the rule. The EPA filed a petition to the United States Supreme Court on October 17, 2008 seeking to overturn the lower court's ruling.

While the Supreme Court considers whether to grant the petition for a writ of certiorari, all new coal fueled electric generating units and modifications of existing units will be required to obtain permits under Section 112 (g) of the Clean Air Act.[7] Under this provision, if no applicable emission limits have been established for a category of listed hazardous air pollutant sources, no person may construct a new major source or modify an existing major source in the category unless the EPA Administrator or the delegated state agency determines on a case by case basis that the unit will meet standards equivalent to the maximum achievable emission controls. Thus, new major sources or modifications to an existing major source would be required to perform a case by case analysis of the maximum achievable control technology and meet the emissions limitation that could be achieved in practice by the best performing sources in that category. If the Supreme Court decides to hear the appeal, any required maximum achievable control technology analysis requirement will likely be stayed for the duration of the rehearing. Until the court or the EPA take further action, it is not known the extent to which future mercury rules may impact PacifiCorp's current plans to reduce mercury emissions at their coal-fired facilities.

PacifiCorp is committed to responding to environmental concerns and investing in higher levels of protection for its coal-fired plants. PacifiCorp and MEHC anticipate spending $1.2 billion over a ten-year period to install necessary equipment under future emissions control scenarios to the extent that it's cost-effective.

CLIMATE CHANGE

Climate change has emerged as an issue that requires attention from the energy sector, including utilities. Because of its contribution to United States and global carbon dioxide emissions, the U.S. electricity industry is expected to play a critical role in reducing greenhouse gas emissions. In addition, the electricity industry is composed of large stationary sources of emissions that are thought to be often easier and more cost-effective to control than from numerous smaller sources. PacifiCorp and parent company MidAmerican Energy Holdings Company recognize these issues and have taken voluntary actions to reduce their respective CO_2 emission rates. PacifiCorp's efforts to achieve this goal include adding zero-emitting renewable resources to its

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[7] Refer to the memorandum from Robert Meyers, Deputy Assistant Administrator, Environmental Protection Agency, Office of Air and Radiation, dated January 7, 2009.

generation portfolio such as wind, geothermal, landfill gas, solar, combined heat and power (CHP), and hydro capacity upgrades, as well as investing in on-system and customer-based energy efficiency and conservation programs. PacifiCorp also continues to examine risk associated with future CO_2 emissions costs. The section below summarizes issues surrounding climate change policies.

Impacts and Sources

As far as sources of emissions are concerned, according to the U.S. Energy Information Administration, CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption. Among fossil fuel types, coal has the highest carbon content, natural gas the lowest, and petroleum in-between. In the Administration's *Annual Energy Outlook 2009 Early Release* reference case, energy-related CO_2 emissions reflect the quantities of fossil fuels consumed and, because of their varying carbon content, the mix of coal, petroleum, and natural gas. Given the high carbon content of coal and its use currently to generate more than one-half of U.S. electricity, prospects for CO_2 emissions depend in part on growth in electricity demand. Electricity sales growth in the *AEO2009* reference case slows as a result of a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, housing patterns, and economic activity. With slower electricity growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related CO_2 emissions grow by just 0.5 percent per year from 2007 to 2030. CO_2 emissions from transportation activity also slow in comparison with the recent past, as Federal CAFE standards increase the efficiency of the vehicle fleet, and higher fuel prices moderate the growth in travel.

Taken together, all these factors tend to slow the growth of the absolute level of primary energy consumption and promote a lower carbon fuel mix. As a result, energy-related emissions of CO_2 grow by 7 percent from 2007 to 2030—lower than the 11-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive as CO_2 emissions grow by about one-tenth of the increase in GDP, and emissions per capita decline by 14 percent.

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

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

International and Federal Policies

Numerous policy activities have taken place and continue to develop. At the global level, most of the world's leading greenhouse gas (GHG) emitters, including the European Union (EU), Japan, China, and Canada, have ratified the Kyoto Protocol. The Protocol sets an absolute cap on GHG emissions from industrialized nations from 2008 to 2012 at seven percent below 1990 levels. The Protocol calls for both on-system and off-system emissions reductions. While the U.S. has thus far rejected the Kyoto Protocol, numerous proposals to reduce greenhouse gas emissions have been offered at the federal level. The proposals differ in their stringency and choice of policy tools.

In June 2008, the Lieberman-Warner Bill—the Climate Security Act (CSA)—failed in the Senate. The CSA set a goal for reducing greenhouse gas emissions of more than 60 percent by 2050.[8] Furthermore, the CSA sought to institute a domestic offset program that would allow facilities to meet up to 15 percent of their compliance with allowances generated by offset projects, or by purchasing or borrowing credits. The CSA also included a "Bonus Allowance Account" whereby companies would be awarded for sequestering their carbon emissions.[9] Perceived effects on the national economy derailed the CSA's passage. The EPA estimated the CSA would decrease the nation's gross domestic product between $238 billion and $983 billion by 2030, while increasing electricity prices 44 percent by 2030.[10] Further, due to rising electricity costs the average household's consumption would decrease an average of $1,375 by 2030.[11]

In addition to the CSA, On October 7, 2008, the former Chairman of the Committee on Energy and Commerce, John D. Dingell, released draft climate change legislation calling for the lowering of emissions to 80 percent of 2005 levels by 2050. The draft legislation proposes to balance its costs through high quality offsets, special reserve emission allowances, and carbon capture and sequestration.[12]

Recent Democratic victories in the House, Senate and the Presidency appear likely to boost efforts to strengthen U.S. global warming policy. Congress and federal policy makers are considering climate change legislation and a variety of national climate change policies and President Obama has expressed support for an economy-wide greenhouse gas cap and trade program that would reduce emissions 80 percent below 1990 levels by 2050. As a result of these policies, PacifiCorp's electric generating facilities are likely to be subject to regulation of greenhouse gas emissions within the next several years.

U.S. Environmental Protection Agency's Advance Notice of Public Rulemaking

On July 11, 2008, the Environmental Protection Agency released an Advance Notice of Proposed Rulemaking inviting public comment on the benefits and ramifications of regulating greenhouse gases under the Clean Air Act. This Advance Notice of Proposed Rulemaking is one

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[8] Erin Kelly, "Senate Poised to Take Up Sweeping Global Warming Bill," USA Today, http://www.usatoday.com/news/washington/environment/2008-05-17-global-warming_N.htm, May 17, 2008.

[9] *Id.*

[10] U.S. EPA, EPA Analysis of the Lieberman-Warner Climate Security Act of 2008, available at: http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf.

[11] "U.S. Environmental Protection Agency Estimates Cost of Lieberman-Warner Bill to Limit Greenhouse Gas Emissions," National Rural Electric Cooperative Association, available at: http://www.nreca.org/main/NRECA/PublicPolicy/issuespotlight/20080319ClimateChange.htm, March 19, 2008.

[12] John D. Dingell, Climate Change Discussion Draft Legislation, U.S House of Representatives, Committee on Energy and Commerce, October 7, 2008; For a complete list of the cap-and-trade legislation introduced in Congress in 2008, see http://www.pewclimate.org/docUploads/Chart-and-Graph-120108.pdf.

of the steps the Environmental Protection Agency has taken in response to the United States Supreme Court's decision in *Massachusetts v. Environmental Protection Agency*.[13] A decision to regulate greenhouse gas emissions under one section of the Clean Air Act could or would lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants.

The Advance Notice of Proposed Rulemaking reflects the complexity and magnitude of the question of whether and how greenhouse gases could be effectively controlled under the Clean Air Act. Many of the key issues for discussion and comment in the Advance Notice of Proposed Rulemaking included:

- Descriptions of key provisions and programs in the Clean Air Act, and advantages and disadvantages of regulating greenhouse gas emissions under those provisions.
- How a decision to regulate greenhouse gas emissions under one section of the Clean Air Act could or would lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants.
- Issues relevant for Congress to consider for possible future climate legislation and the potential for overlap between future legislation and regulation under the existing Clean Air Act.
- Scientific information relevant to, and the issues raised by, an endangerment analysis.
- Information regarding potential regulatory approaches and technologies for reducing greenhouse gas emissions.

The Environmental Protection Agency accepted public comment on the Advance Notice of Proposed Rulemaking until November 28, 2008. PacifiCorp's parent, MidAmerican Energy Holdings Company submitted comments on the Advance Notice of Proposed Rulemaking. In these comments, MidAmerican stressed the Company's position that Clean Air Act regulations are an inferior strategy for reducing greenhouse gas emissions compared to a comprehensive legislative program that Congress is expected to enact. Promulgating greenhouse gas regulations under the Clean Air Act would be, at best, unnecessary because Congress is expected to enact a program that is economy-wide, market-based, incents technology, and encourages other countries to take action. MidAmerican further highlighted that any mandatory domestic program to reduce greenhouse gas emissions should be implemented consistent with the following principles:

- Technology development and deployment is essential to achieving a 60 to 80 percent reduction in greenhouse gas emissions. A significant national commitment to funding and advancing low-carbon technologies is critical.

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[13] In April 2007, the Supreme Court concluded in that case that greenhouse gas emissions meet the Clean Air Act definition of "air pollutant," and that section 202(a)(1) of the Clean Air Act therefore authorizes regulation of greenhouse gas emissions subject to an Agency determination that greenhouse gas emissions from new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare (Endangerment Finding).

- Immediate opportunities for emissions reduction and avoidance should be pursued through investments in energy efficiency, renewable energy and increasing the efficiency of existing generation.
- Any program to regulate greenhouse gas emissions should seek to avoid short-term responses that do not provide a long-term path to a low carbon future.
- Programs implemented to reduce greenhouse gas emissions should achieve their intended purpose—reducing or avoiding emissions—and not simply serve as a source of revenue or offsetting taxes.

In April 2009, the EPA found that concentrations of CO_2 and five other greenhouse gases pose dangers to human health and welfare, and is in the process of holding public hearings on further action to regulate these greenhouse gases under the Clean Air Act.

Regional State Initiatives

Activities undertaken by regional state climate change initiatives continued to be significant in 2008 and will continue into 2009. The most notable developments are as follows:

Midwestern Regional Greenhouse Gas Accord

On November 3, 2008, the ten Midwestern Regional Greenhouse Gas Accord Partners released Draft Recommendations, suggesting a target of between 15-25 percent below 2005 levels by 2020 and a target of between 60-80 percent below 2005 levels by 2050. They also recommended that the program cover a comprehensive slate of activities including electricity generation and imports, industrial combustion sources, credible and measurable industrial process sources, transportation fuels, and fuels serving residential, commercial, and industrial buildings. The Advisory Group hopes to include 85-95 percent of emissions for each sector, and suggests linking the Midwestern Greenhouse Gas Accord cap-and-trade program to the Regional Greenhouse Gas Initiative, Western Climate Initiative, and other mandatory greenhouse gas emissions reduction programs.

Regional Greenhouse Gas Initiative

In 2008, the ten Regional Greenhouse Gas Initiative Partners held successful pre-compliance auctions in September and December. The first auction sold 12,565,387 carbon dioxide allowances at a clearing price of $3.07 per allowance, raising more than $38.5 million. The second auction sold 31,505,898 allowances at a clearing price of $3.38 per allowance, raising more than $106 million. Under the Regional Greenhouse Gas Initiative, this combined $140 million will be used on a wide variety of approved efforts to limit and sequester carbon, as well as adapt to the impacts of climate change.

Western Climate Initiative

In September 2008, the Western Climate Initiative Partners released their proposal for a regional cap-and-trade program beginning in 2012. The seven states and four provinces would cover 20 percent of the United States, and 70 percent of the Canadian, economies respectively. Covered emitters include electricity generators and industrial and commercial stationary sources that emit more than 25,000 metric tons of carbon dioxide equivalent per year. Beginning in 2015, the market would expand to also cover petroleum-based fuel combustion from residential, commercial, and industrial operations, for an overall goal of reducing emissions to 15 percent below 2005 levels by 2020.

Individual State Initiatives

State Economy-wide Greenhouse Gas Emission Reduction Goals

An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to, (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. Oregon's goals seek to (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2008, Colorado announced Executive Order D-004-08, setting a goal of reducing greenhouse gas emissions to 20 percent below 2005 levels by 2020, and 80 percent below 2005 levels by 2050. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

State Greenhouse Gas Emission Performance Standards

In addition, California and Washington have adopted legislation that impose greenhouse gas emission performance standards to all electricity generated within the state or delivered from outside the state to serve retail load. The greenhouse gas emissions performance standard is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility, effectively prohibiting the use of new pulverized coal generation to serve retail load. The state of Idaho had adopted a de-facto prohibition on new pulverized coal generation located within the state when it decided not to participate in the federal Clean Air Mercury Rule's cap-and-trade program, and as a result received a zero state budget for mercury emissions.

Other Recent State Accomplishments

In October 2008, the California Public Utilities Commission and the California Energy Commission completed a collaborative proceeding to develop and provide recommendations to the California Air Resources Board on measures and strategies for reducing greenhouse gas emissions in the electricity and natural gas sectors. The October 16, 2008 final decision[14] is the second policy decision to be issued pursuant to this effort. In an earlier decision, Decision 08-03-018 issued in March 2008, the Commissions provided their initial greenhouse gas policy recommendations to the Air Resources Board. In December, the Air Resources Board adopted the "Assembly Bill 32 Scoping Plan to Reduce Greenhouse Gas Emissions in California." The strategy relies on 31 new rules, including a cap-and-trade program, set to begin in 2012, impacting power plants, refineries, and large factories. Assembly Bill 32 (2006) requires California to cut greenhouse emis-

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[14] Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, available at: http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/92288.pdf .

sions to 1990 levels by 2020. The Air Resources Board is also implementing mandatory greenhouse gas reporting with a regulation that was approved by the Board in December 2007, and became effective on December 2, 2008.[15]

In October 2008, the Oregon Environmental Quality Commission approved new mandatory greenhouse gas reporting rules. The reporting rules are aimed at developing a statewide strategy for reducing emissions to 10 percent below 1990 levels by 2020, and to 75 percent below 1990 levels by 2050. Additionally, the Legislature passed Oregon House Bill 3619 expanding the business energy tax credit program with additional incentives for manufacturers of renewable energy equipment located in Oregon. Senate Bill 80, which implements a state CO_2 cap-and-trade system and emission reporting rules, is under consideration.

In 2008, the Utah Legislature passed Senate Bill 202 establishing a renewable energy target of 20 percent by 2025, with zero-carbon emitting electricity facilities exempt from the target. The bill also establishes a process for establishing a carbon capture and storage regulatory framework. The Utah Carbon Capture and Geologic Sequestration Workgroup was subsequently formed.

In June 2008, the Washington Department of Ecology adopted its final rules implementing a greenhouse gas emissions performance standard of 1,100 pounds of greenhouse gas per megawatt (MW) for all new electrical generation built within Washington, or used to serve the Washington retail load. The Department also adopted guidelines for carbon capture and sequestration projects. House Bill 2815 directs the Department of Ecology to develop, in coordination with the Western Climate Initiative, a design for a cap and trade system to meet the state's greenhouse gas emissions reductions limits of 50 percent below 1990 levels by 2050. In December 2008, the Department delivered to the legislature specific recommendations for approval, and requested authority to implement the preferred design of the greenhouse gas reduction system in order to have the system in effect by January 1, 2012.[16] Second, House Bill 2815 requires operations emitting at least 10,000 metric tons, or on-road motor vehicle fleets that emit 2,500 tons of greenhouse gases, to report their emissions to the Washington Department of Ecology beginning in 2010 for 2009 emissions. House Bill 2687 addresses the Department of Ecology's authority and direction for participation in the Western Climate Initiative, and directs the state to ensure that a design for a cap-and-trade system confers equitable economic benefits and opportunities to electric utilities. Further, the language directs the state to advocate for a regional system that addresses competitive disadvantages that could be experienced because of implementing strict greenhouse gas reduction programs. Senate Bill 6580 requires the Department of Community, Trade, and Economic Development to develop and provide advisory climate change responses to counties and cities, establish a local government global warming mitigation and adaptation program to address climate change through land use and transportation planning, and present a report to the legislature regarding policies to address and assess the impacts of climate change.

Wyoming House Bill 89, Pore Space Ownership, and House Bill 90, Carbon Capture and Sequestration, were signed into law on March 4, 2008. House Bill 89 is intended to affirm the

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[15] Mandatory Greenhouse Gas Emissions Reporting, available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

[16] Growing Washington's Economy in a Carbon-Constrained World: A Comprehensive Plan to Address the Challenges and Opportunities of Climate Change, available at: http://www.ecy.wa.gov/pubs/0801025.pdf.

"American or Majority Rule" that the ownership of "pore space" in underground strata below the surface lands and waters of the state of Wyoming is vested in the several owners of the surface, but can be severed from the surface rights and sold separately. "Pore space" is defined to mean subsurface space that can be used as storage space for CO_2 or other substances. Wyoming House Bill 90 establishes a permit program for carbon storage and sequestration underground injection wells. The law establishes a permit program for injection of CO_2 and associated constituents for sequestration to be issued by Wyoming Department of Environmental Quality. The law specifically states that injection of CO_2 for enhanced recovery of oil or gas approved by Wyoming Oil and Gas Conservation Commission is not subject to the new permit program. The Wyoming Carbon Sequestration Working Group was subsequently formed. [17]

Corporate Greenhouse Gas Mitigation Strategy

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

- **Policy –** PacifiCorp has supported legislation that enables GHG reductions while addressing core customer requirements. PacifiCorp will continue to work with regulators, legislators, and other stakeholders to identify viable tools for GHG emissions reductions.
- **Planning –** PacifiCorp has incorporated a reasonable range of values for the cost of CO_2 in the 2008 IRP in concert with numerous alternative future scenarios to reflect the risk of future regulations that can affect relative resource costs. The Company is engaged in augmenting its regulatory analysis capabilities, including enhancing its IRP models to capture a more detailed representation of climate change rules. It is involved with such organizations as the Electric Power Research Institute for continued study of regulatory impacts on utilities and customers. Additional voluntary actions to mitigate greenhouse gas emissions could increase customer rates and represent key public policy decisions that the Company will not undertake without prior consultation with regulators and lawmakers at state and federal levels.
- **Procurement –** PacifiCorp recognizes the potential for future CO_2 costs in requests for proposal (RFPs), consistent with its treatment in the IRP. Commercially available carbon-capturing and storage technologies at a utility scale do not exist today. Carbon-capturing technologies are under development for both pulverized coal plant designs and for coal gasification plant designs, but require research to increase their scale for electric utility use.
- **Accounting –** PacifiCorp has adopted transparent accounting of GHG emissions by joining the California Climate Action Registry. The Registry applies rigorous accounting standards, based in part on those created by the World Business Council on Sustainable Development and the World Resources Institute, to the electric sector.

The current strategy is focused on meaningful results, including installed renewables capacity and effective demand-side management programs that directly benefit customers. While these efforts provide multiple benefits of which lower GHG emissions are a part, they are clearly attractive within an effective climate strategy and will continue to play a key role in future procurement efforts.

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[17] http://deq.state.wy.us/carbonsequestration.htm

EPRI ANALYSIS OF CO_2 PRICES AND THEIR POTENTIAL IMPACT ON THE WESTERN U.S. POWER MARKET

In 2008, the Electric Power Research Institute (EPRI) organized and conducted a broad-brush study to identify and analyze the likely effects of climate change policy for western U.S. (WECC region) generators and customers. A diverse collection of nine western generation companies, including PacifiCorp, funded and participated extensively in this effort.

The WECC region has certain unique power system characteristics, which make it an interesting laboratory to study the effects of climate policy. These include a large existing base of hydro generation supporting the regional market, as well as a growing collection of state-level Renewable Portfolio Standard targets. These existing and anticipated generation resources together form an important baseline serving this region if their potential can be realized. On the other hand there are significant uncertainties surrounding this realization, including the sustainability of hydro generation into the future, and the feasibility of infrastructure investments (i.e. transmission capacity, backup generation) needed to realize such an extensive renewables build out.

The study results attempt to reflect and recognize uncertainties in future power markets, through an examination of several alternative future scenarios. A Reference Case, reflecting a largely stable and optimistic future, was described for baseline purposes. In addition, a case called "Wild Card", reflecting a more pessimistic view of future events, was presented as an alternative. The study was designed to examine macro-level effects of alternative CO_2 price levels on power system dispatch, new generation investment decisions, emissions levels and power prices. The analysis included: representation of a full electric system supply-demand balance; capacity expansion and retirement methodology driven by the relative economics of both existing and new resources, and; a demand response representation, allowing future load growth to respond to future price changes.

Key conditioning assumptions of the Reference Case include: future load growth in this market was assumed equal to the recent historical period 1995-2005, at 1.73 percent per year; natural gas prices (real 2006 dollars) were set to a recent (May 6, 2008) NYMEX forward curve projection through the year 2020, then held constant at 2020 levels; capital costs for new generating plant were driven by EPRI internal estimates from 2007, and further inflated 25 percent in recognition of continual and inexorable escalation (at least until very recently) in all global construction markets, and; western state RPS targets were assumed to be met in future years, per individual state law.

The behavior of the power system and electric customers was investigated over a future period 2006 through 2030, for a series of CO_2 price points (starting at $0/ton and escalating up to $100/ton) imposed beginning in 2012. The analysis assumed that the CO_2 price would remain constant (in real 2006 $) from 2012 through 2030. This flat scenario CO_2 price structure was designed to show how the electric sector would equilibrate to specific prices levels over time.

The results of this analysis show, in the first instance, that a higher CO_2 price will drive up the power price and drive down emissions. The power price in the initial year (2012) increases almost linearly with the CO_2 price, because the power system has very limited response capability in the very short term. There is some capability to switch resource usage from coal to natural gas, but it is actually quite limited in WECC, so the only real option is to pass price increases on to consumers. Similarly, the short-term ability to reduce emissions is virtually nil except at very high CO_2 prices where the level of demand itself is reduced through price effects.

This inflexibility is much less true as time marches on. In later years the response is both more pronounced for emissions and more limited for power prices, as the generating stock begins to turn over and new investments are made in non-emitting generation. Note in particular that emissions reductions by 2030 accelerate significantly once the \$50-\$60 CO_2 price range is reached, when nuclear generation starts to penetrate the market. It is only when wholesale power prices reach roughly the \$100 range that the nuclear technology can expect to cover its investment and carrying costs. The response of power price to CO_2 price is also more moderated in later years, as low-busbar cost, non-emitting technologies enter the mix and temper power prices.

The generation mix details of these phenomena are equally illuminating. In the absence of a CO_2 policy the existing mix of generation is not appreciably affected. As time marches into the future, demand growth is largely met with new renewable generation and new natural gas-fired generation. A small amount of customer response to rising prices tempers demand growth just a bit. Emissions keep growing.

A \$50/ton CO_2 price brings about noticeable future changes. In the first instance, it is interesting to note that this represents the “stabilization” price, or the price that essentially flattens emissions growth into the future. As power prices are also driven up in this case, customer response is also greater and demand growth is tempered even further. Higher power prices also begin to affect the generation mix, pushing out existing coal over time and eliciting more gas generation as replacement energy. Notably, at a \$50 CO_2 price there is still little change in the overall generation mix over time, as the power price is not yet quite high enough to usher in significant capacity in non-emitting technologies.

At CO_2 prices of \$85 and higher, the generation mix begins to change noticeably due to the new technology opportunities presented by higher power prices. Note first that in this case emissions shrink significantly over time, in reaction to both increased customer price response and to changes in generation technology. Existing coal generation shrinks virtually to nothing by 2030, and is replaced in part with non-emitting nuclear generation – assumed to be available in the 2020 timeframe – as well as renewables. On the other hand, power prices actually moderate over time at the \$85 CO_2 level, due in large part to the switch out of coal generation (and its \$85/ton surcharge) and into very low busbar-cost alternatives such as nuclear and renewables.

An alternative, more pessimistic case was investigated as well. The “Wild Card” case represents an alternative future – one in which both events and policy responses to them work against future greenhouse gas control. Key differences in assumptions for the “Wild Card” case include: an assumed higher load growth rate; assumed higher natural gas prices; higher capital costs (25 percent premium); an assumed lower customer demand response, and; assumed nuclear power unavailability for the duration of the study.

The “Wild Card” future requires a higher CO_2 price than the Reference Case to stabilize emissions over time (closer to the \$70-\$80 range). Due to higher capital costs overall, as well as the nuclear penetration constraint, capital stock turnover is much more sluggish in the pre-2030 time frame, and emissions are still growing at the \$50 CO_2 price level. Existing generation – coal and gas – is necessarily used more heavily, and emissions stubbornly resist reduction.

Even at a \$100 CO_2 price, emissions reductions in the "Wild Card" case are still minimal. In fact it takes a CO_2 price in the range of \$125-\$150 to effect significant reduction, under a "Wild Card" future.

Power prices are impacted as well. The "Wild Card" future leads to a persistent \$20 premium in wholesale power prices, regardless of the size of the CO_2 price assumed.

The foregoing analysis of western power markets was an attempt to postulate several alternative futures, and examine the implications of each on suppliers and consumers. The analysis is aggregate – high-level and suggestive – and certainly glosses over many details and intricacies in an attempt to focus squarely on the larger picture. Many "devils in the details" have been undoubtedly simplified, including the following.

All details of power system operations are treated abstractly, at best. This abstraction is clearest in the representation of renewable generation and its growth potential. Realistically, there will need to be significant infrastructure (i.e. transmission capacity, backup combustion turbine generation or energy storage to mitigate intermittency) built in the west, additional to renewable generation capacity, to support its usage. This additional infrastructure has been represented in the analysis as a simple capital adder to the renewables cost estimate. Whether this additional investment will be financially - or politically - feasible is certainly an open question. It may be that the renewables contribution has been overestimated. On the other hand, the base renewables projections (the vast bulk of the renewables capacity in any scenario) used in this analysis are merely what has been mandated by numerous western states as their avowed targets, and these targets are already today well within reach in many states.

Natural gas prices are also an important driver of the analysis, and they have been notoriously volatile for the last 30 years. Among knowledgeable professionals there are resource depletion arguments that indicate prices will go up, and liquefied natural gas emergence arguments that indicate prices will go down. Still and all, the NYMEX forward curve remains the best consensus estimate of what will happen to gas prices in the future; this has formed the basis of the estimates in this analysis.

Customer response to price changes is universally recognized as a real phenomenon, and just as universally acknowledged as impossible to accurately measure. In this analysis the long-term elasticity parameter finally chosen (-0.50) is based on EPRI studies from early in the decade, but it could well be overstated.

The above caveats notwithstanding, there are several important conclusions that can be drawn from the analysis. These include the following.

It is certainly possible to wring emissions growth out of the power sector in western states, given high enough CO_2 price signals and sufficient time. In the Reference Case future, a price of about \$50 will flatten emissions growth, and a price of about \$80 will substantially reduce it. In the "Wild Card" future, it will require about an \$80 price to flatten growth and a price in excess of \$125 to make substantial reductions.

CO_2 prices in these ranges are unprecedented, and will lead to unprecedented retail power prices as well, in the range of 40-80 percent higher (depending on CO_2 price level)—in the immediate aftermath of price imposition—than they are in WECC today. Such levels will cause anxiety for the electricity sector and its customers as well. However, over time (18 years is the horizon of this analysis, actually, higher prices will create investment incentives for the addition of non-emitting generation, and more such capacity will enter the market if it functions reasonably well. This will tend to temper power price differentials over time. In the analysis retail prices in 2030 are projected to end up more like 15-30 percent higher than the \$0 case, a far cry from the differentials in 2012.

Customer response to price increases will tend to hold power price levels down in its turn as well. Without this effect prices might be expected to rise even higher. This is a mixed blessing at best, as it will represent a real loss in consumer welfare, albeit not measured explicitly in the analysis.

Natural gas price and availability are critical linchpins in the Western power system in early years, as short-term reductions in emissions will depend on the ability of natural gas generation to fill the gaps left by coal cutbacks. This criticality will fade over time, as new non-emitting technologies increasingly will enter the market and fill the void.

For the western power industry, the EPRI analysis helps inform possible decisions by highlighting two important CO_2 price signals necessary to effectuate changes within the electricity sector. The first is the CO_2 price that is just high enough to encourage a utility interested in building new electricity generation to choose a lower-emitting—albeit more expensive—technology over a cheaper, but higher-emitting technology. A second CO_2 price is one that is sustained at a high enough level as to make existing fossil-fueled power plants uneconomic to continue operating. Under either situation, higher costs will inevitably be passed on to consumers in the form of higher electricity rates, but if accompanied by sufficient time to adapt to the new regulatory regime, costs can be mitigated.

ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

In late December 2007, Congress passed the Energy Independence and Security Act (P.L. 110-140, which has three major provisions covering corporate average fuel economy standards, the renewable fuels standard, and appliance/lighting efficiency standards.

For corporate average fuel economy, the law sets a target of 35 miles per gallon for the combined fleet of cars and light trucks by model year 2020. Also, a fuel economy program is established for medium- and heavy-duty trucks, and a separate fuel economy standard is created for work trucks. These were the first new corporate average fuel economy standards in 32 years, and the increases represent a roughly 40 percent increase over today's requirements.

For the renewable fuels standard, the law sets a modified standard that starts at 9.0 billion gallons of renewable fuel in 2008 and rises to 36 billion gallons by 2022. Of the latter total, 21 billion gallons is required to be obtained from cellulosic ethanol and other advanced biofuels. This represents a six-fold increase over the mandate that is in place.

In the area of energy efficiency (specifically appliance and lighting efficiency standards), the law set energy efficiency standards for broad categories of incandescent lamps (light bulbs), incandescent reflector lamps, and fluorescent lamps. A required target is set for lighting efficiency, and energy efficiency labeling is required for consumer electronic products. The law will effectively phase out most common types of incandescent light bulbs over the next four to six years by increasing the energy efficiency standards of light bulbs by 30 percent. The new standard is technology-neutral, allowing consumers a choice among several efficient lighting technologies, including improved halogen-incandescent bulbs, compact fluorescent lamps and eventually light-emitting diodes and other advanced lighting technologies. The impact of the lighting efficiency standards has been accounted for in PacifiCorp's load forecasting and IRP portfolio modeling (See Chapter 5, Resource Needs Assessment). Efficiency standards are set by law for external power supplies, residential clothes washers, dishwashers, dehumidifiers, refrigerators, refrigerator/freezers, freezers, electric motors, residential boilers, commercial walk-in coolers, and commercial walk-in freezers. Further, the U.S. Department of Energy is directed to set standards by rulemaking for furnace fans and battery chargers.

The Act also requires a 30 percent reduction in energy consumption by 2015 in federal buildings. (The General Services Administration owns and leases over 340 million square feet of space in more than 8,900 buildings, located in every state.)

The Act also encourages the development of carbon capture technology by (1) expanding and improving the Department of Energy's existing carbon sequestration research, (2) requiring a national assessment of capacity to sequester carbon, (3) requiring the Secretary of Energy to conduct seven large-scale geologic sequestration tests, with at least one as an international partnership, an d(4) increasing the funding authorization for all projects included in the new carbon capture and storage research, development and demonstration program, with an emphasis on large-scale geologic carbon dioxide injection demonstration projects.

Another title of the Act is the Advanced Geothermal Energy Research and Development Act of 2007. It calls for research, development, demonstration, and commercial application in five major areas: (1) geopressured resource production, which is co-produced in oil and gas fields; (2) cost-sharing drilling; (3) enhanced geothermal systems; (4) creation of a national exploration and development geothermal technology transfer and information center; and (5) international geothermal collaboration.

RENEWABLE PORTFOLIO STANDARDS

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

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

RPS policies are currently implemented at the state level (although interest in a federal RPS is expanding), and vary considerably in their requirements with respect to time frame, resource eligibility, treatment of existing plants, arrangements for enforcement and penalties, and whether they allow trading of renewable energy credits. By 2008, twenty-five states adopted mandatory renewable portfolio standards, five states adopted voluntary renewable portfolio standard, and fourteen states had adopted no form of renewable portfolio standard.

Within PacifiCorp's service territory, California, Oregon, and Washington have mandatory renewable portfolio standards, with Utah having adopted a voluntary renewable portfolio standard. Each state is summarized in Table 3.1 and additional discussion below.

Table 3.1 – Summary of state renewable goals (as applicable to PacifiCorp)

State	Goal
California	Obtain 20 percent of electricity from renewable resources by 2010.
Oregon	Obtain 25 percent of electricity from renewable resources by 2025 in the following increments: • 5 percent: 2011 – 2014 • 15 percent: 2015 – 2019 • 20 percent : 2020 – 2024 • 25 percent: 2025 and beyond
Utah	By 2025, obtain 20 percent of annual adjusted retail sales from cost effective renewable resources, as determined by the Public Service Commission or renewable energy certificates.
Washington	Obtain 15 percent of electricity from renewable resources by 2020 in the following increments: • 3 percent by January 1, 2012 through December 31, 2015 • 9 percent by January 1, 2016 through December 31, 2019 • 15 percent by January 1, 2020 and each year thereafter

California

California law requires electric utilities to increase their procurement of renewable resources by at least one percent of their annual retail electricity sales per year so that 20 percent of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities received further guidance from the California Public Utilities Commission on the treatment of small multi-jurisdictional utilities in the California Renewable Portfolio Standard program within decision, D.08-05-029. In August 2008, concurrent with its annual renewable portfolio standard compliance filing, PacifiCorp, joined by Sierra Pacific Power Company, filed a Joint Motion for Review of the decision. As discussed in D.08-05-029, since the inception of the Renewable Portfolio Standard program, PacifiCorp and other small multi-jurisdictional utilities operated in a state of regulatory uncertainty regarding the nature of their Renewable Portfolio Standard program compliance obligations. PacifiCorp's filing represented its interpretation of D.08-05-029, including banking of renewable portfolio standard procurement made while it awaited further guidance from the California Public Utilities Commission on the treatment of small multi-jurisdictional utilities during the 2004-2006 period. PacifiCorp believes its interpretation is consistent with D.08-05-029 and best serves the interests of its customers by recognizing past, good faith efforts to comply with California's Renewable Portfolio Standard program beginning January 1, 2004. PacifiCorp is currently awaiting the California Public Utilities Commission's response to the Joint Motion for Review.

Oregon

In June 2007, the Oregon Renewable Energy Act was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council area, and unbundled renewable energy credits can be used. The Oregon Public Utilities Commission and the Oregon Department of Energy have undertaken additional rulemaking proceedings to further implement the initiative.

Utah

In March 2008, Utah's governor signed Utah Senate Bill 202, "Energy Resource and Carbon Emission Reduction Initiative;" legislation supported by PacifiCorp. Among other things, this provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used.

Washington

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are three percent of retail sales by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020. Qualifying renewable energy sources must be located within the Pacific Northwest. The Washington Utilities and Transportation Commission adopted final rules to implement the initiative.

Federal Renewable Portfolio Standard

Congress has taken up federal energy policy legislation, including the possibility of a federal RPS. President Obama has pledged to "spark the creation of a clean energy economy" as part of his plan aimed at reinvigorating the U.S. economy, in part by doubling production of "alternative energy" in the next three years—aided by subsidies for "low emissions coal plants," biofuels and renewable energies—and by pursuing a federal renewable portfolio standard mandating that 25 percent of U.S. electricity come from renewable sources by 2025. Passage of a federal renewable portfolio standard would break a major standoff in Congress as both the House and Senate have passed various forms of a renewable portfolio standard in recent years but failed to concur on the details. The Waxman-Markey Bill represents the latest effort, and specifies a renewable electric compliance requirement of 20 percent by 2020.

Proponents of a national renewable portfolio standard argue it would ease the move toward a mandatory cap on greenhouse gas emissions by requiring utilities to invest in low-carbon energy sources. Enactment of a federal renewable portfolio standard would be a significant shift in the way electric utilities are regulated, dramatically increasing the authority of the federal government to dictate the makeup of a utility's energy portfolio—a power currently exercised by state governments.

Renewable Energy Certificates

Absent either a RPS compliance obligation or an opportunity to bank unbundled renewable energy certificate (RECs) for future year RPS compliance, PacifiCorp has historically relied on an assumption that a renewable project may generate $5 per megawatt-hour for five years from the sale of unbundled RECs. Unbundled REC sales have helped mitigate the near-term cost differential between new renewable resources and traditional generating resources.

However, once greenhouse gas emissions are regulated, surplus unbundled REC sales would cease. PacifiCorp assumes if an unbundled REC is sold, then the underlying power (aka "null" power) would likely have a carbon emissions rate imputed upon it by regulatory authorities, thus obligating PacifiCorp to purchase either allowances or carbon offsets sufficient to cover the imputed carbon emissions. By selling an unbundled REC, PacifiCorp may generate revenue, but risks incurring a new carbon liability. Once greenhouse gases are regulated—and until the unbundled REC and carbon markets are reconciled—PacifiCorp plans to cease selling unbundled RECs.

HYDROELECTRIC RELICENSING

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

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of two hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary Orders from the Federal Energy Regulatory Commission (FERC). The Klamath River hydroelectric project continues to work with parties to reach a settlement agreement on future project conditions, and the Condit project is seeking a Surrender Order to decommission the project.

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

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

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and generally takes nearly ten or more years to complete, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2008, PacifiCorp had incurred $56.6 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As relicensing and/or decommissioning efforts continue for the Klamath River and Condit hydroelectric projects, additional process costs are being incurred that will need to be recovered from customers. Also, new requirements contained in FERC licenses or decommissioning Orders could amount to over $1.2 billion over the next 30 to 50 years. Such costs include capital and operations and maintenance investments made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect fish resulting in lost generation. Over 95 percent of these relicensing costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

Treatment in the IRP

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

PacifiCorp's Approach to Hydroelectric Relicensing

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

RECENT RESOURCE PROCUREMENT ACTIVITIES

2012 Request for Proposals for Base Load Resources

PacifiCorp issued this RFP on April 5, 2007, to procure up to 1,700 MW of base-load resources for 2012-2014. In December 2008, PacifiCorp submitted an application for "Approval of Significant Energy Resource Decision and for Certificate of Public Convenience and Necessity" to the Public Service Commission of Utah for the Lake Side II combine-cycle plant. As discussed above, in February 2008, the Company terminated the construction contract for this plant.

2008 All-Source Request for Proposals

The 2008 All-Source RFP, which was issued on October 2, 2008, sought up to 2,000 MW of system-wide base-load capacity, intermediate load capacity, third-quarter market purchases, load curtailment, PURPA Qualifying Facilities, and dispatchable/schedulable renewables, with on-line dates between 2012 through 2016.[18] Both the Public Utility Commission of Oregon and the Public Service Commission of Utah approved the RFP.

In late February 2009, PacifiCorp suspended this RFP due to uncertainty caused by the ongoing financial crisis, the economic recession and its impact on loads, and belief that ratepayers and the Company might get a better deal than the proposals submitted in the RFP as the year goes on and markets continue to adjust to the economic environment. Additionally, PacifiCorp also believes suppliers will be much more likely to secure financing once the banking sector has stabilized.

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[18] PacifiCorp's website for competitive solicitations: http://www.pacificorp.com/Article/Article62880.html.

PacifiCorp will monitor the market over the next six to eight months with the intention to lift the suspension, issue an Amendment to the RFP and request updated proposals from the existing bidders and new proposals. PacifiCorp also intends to refresh its benchmark proposals at that time.

Renewable Request for Proposal (RFP 2008R)

PacifiCorp issued RFP 2008R on January 31, 2008 for renewable resources of less than 100 MW for resources greater than five years in length, or greater than 100 MW for resources less than or equal to five years in length. The 2008R RFP solicited renewable resources that have a commercial operation date prior to December 31, 2009. On September 5, 2008, PacifiCorp executed a 20-year power purchase agreement with Duke Energy Corporation for the entire output of the 99-MW Campbell Hill project, located in Wyoming.

Renewable Request for Proposal (RFP 2008R-1)

PacifiCorp issued RFP 2008R-1 on October 6, 2008. This RFP solicited 500 MW of renewable generation projects—with no single resource greater than 300 MW—with on-line dates prior to December, 2011. An amendment to this RFP was filed in Utah on January 12, 2009 and in Oregon on January 8, 2009. Bidders for existing proposals that have been received will have an opportunity to update their pricing. The amendment also allows new bidders to participate. The amendment was filed and approved by the Oregon Public Utility Commission January 20, 2009. The Company has developed its shortlist of bidders, and anticipates making procurement decisions by July 2009. PacifiCorp also filed notices with state commissions regarding its intent to issue its next renewables RFP (2009R).

Demand-side Resources

The Company released a comprehensive demand-side management RFP (2008 DSM RFP) in November 2008. This RFP constitutes one of the items in PacifiCorp's IRP action plan, documented in the 2007 IRP Update report (June 2008, page 25). The 2008 DSM RFP requested bids on eighteen defined products: four Class 1 products and fourteen Class 2 products. The RFP also allowed for proposals on three non-defined products, one for Class 1 load management products, one for Class 2 energy efficiency products, and one for Class 3 price-responsive products. The non-defined product requests allowed bidders to propose products not initially identified in the RFP that they believe may be of benefit to the Company. Contracting for new products accepted under the 2008 DSM RFP will be concluded by mid-summer with regulatory approvals and implementation scheduled to begin the fourth quarter of 2009.

Other procurement work anticipated in 2009 includes the issuance of RFPs for program evaluations of legacy products, engineering resources in support of commercial, industrial and agricultural program delivery, and the procurement of ongoing irrigation load management services in Utah and Idaho.

4. TRANSMISSION PLANNING

PURPOSE OF TRANSMISSION

The basic purpose of PacifiCorp's bulk transmission network is to reliably transport electric energy from generation resources (generation or market purchases) to various load centers. There are several related benefits associated with a robust transmission network:

1. Reliable delivery of power to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably unscheduled outages.
3. Economic exchange of electric power among all systems and industry participants.
4. Development of economically feasible renewable generation in areas where it is best suited.
5. Protection against extreme market conditions where limited transmission constrains energy supply.
6. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff.
7. Increased capability and capacity to access Western energy supply markets.

PacifiCorp's transmission network is a critical component of the IRP process and is highly integrated with other transmission providers in the western United States. It has a long history of reliable service in meeting the bulk transmission needs of the region. Its purpose will become more critical in the future as energy resources become more dynamic and customer expectations become more demanding.

INTEGRATED RESOURCE PLANNING PERSPECTIVE

Transmission constraints and the ability to address capacity or congestion issues in a timely manner represent important planning considerations for ensuring that peak load and energy obligations are met on a reliable basis. The cycle time to add significant transmission infrastructure is often longer than adding generation resources or securing third party resources. Transmission additions must be integrated into regional plans and then permits must be obtained to site and construct the physical assets. Inadequate transmission capacity limits the utilities ability to access what would otherwise be cost effective generating resources.

Transmission assets tend to be long lived which go beyond a twenty-year planning horizon typically considered for resource planning. The result is a set of transmission assets modeled for least cost planning that addresses PacifiCorp's control area needs as well as enables a first-cut evaluation of the impacts of a large multi-state transmission project.

As discussed in the following sections, PacifiCorp is engaged in a significant transmission expansion effort called Energy Gateway that requires cooperative transmission planning with regional and sub-regional planning groups across the Western Interconnection. Transmission infrastructure will continue to play an important role in future IRP plans as segments are added due to Energy Gateway along with other system reinforcement projects.

INTERCONNECTION-WIDE REGIONAL PLANNING

Various regional planning processes have developed over the last several years in the Western Interconnection[19]. It is expected that, in the future, these processes will be the primary forums where major transmission projects are identified, evaluated, developed and coordinated. In the Western Interconnection, regional planning has evolved into a three tiered approach where an interconnection-wide entity, the Western Electricity Coordinating Council (WECC) conducts regional planning at a very high level, several sub-regional planning groups focus with greater depth on their specific areas and transmission providers perform local planning studies within their sub-region. This coordinated planning helps to insure that customers in the region are served reliably and at the least cost.

In 2006, WECC took on a larger and more defined responsibility for interconnection-wide transmission expansion planning under the Federal Energy Regulatory Commission’s Order 890. WECC’s role in meeting the region’s need for regional economic transmission planning and analyses is to provide impartial and reliable data, public process leadership, and analytical tools and services. The activities of WECC in this area are guided and overseen by a board-level committee and the Transmission Expansion Planning Policy Committee (TEPPC).

TEPPC’s three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions compliment but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

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

- Steering decisions on key assumptions and the process by which economic transmission expansion planning data are collected, coordinated and validated;
- Approving transmission study plans, including study scope, objectives, priorities, overall methods/approach, deliverables, and schedules;
- Steering decisions on analytical methods and on selecting and implementing production cost and other models found necessary;
- Ensuring the economic transmission expansion planning process is impartial, transparent, properly executed and well communicated;
- Ensuring that regional experts and stakeholders participate, including state/provincial energy offices, regulators, resource and transmission developers, load serving entities, environmental and consumer advocate stakeholders through a stakeholder advisory group;

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[19] The Western Interconnection stretches from Western Canada South to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.

- Advising the WECC Board on policy issues affecting economic transmission expansion planning; and
- Approving recommendations to improve the economic transmission expansion planning process.

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

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

Similar to the TEPPC activities and process at WECC, a similar process exists under the oversight of the Planning Coordination Committee which provides for the reliability aspects of transmission system planning.

Sub-regional Planning Groups

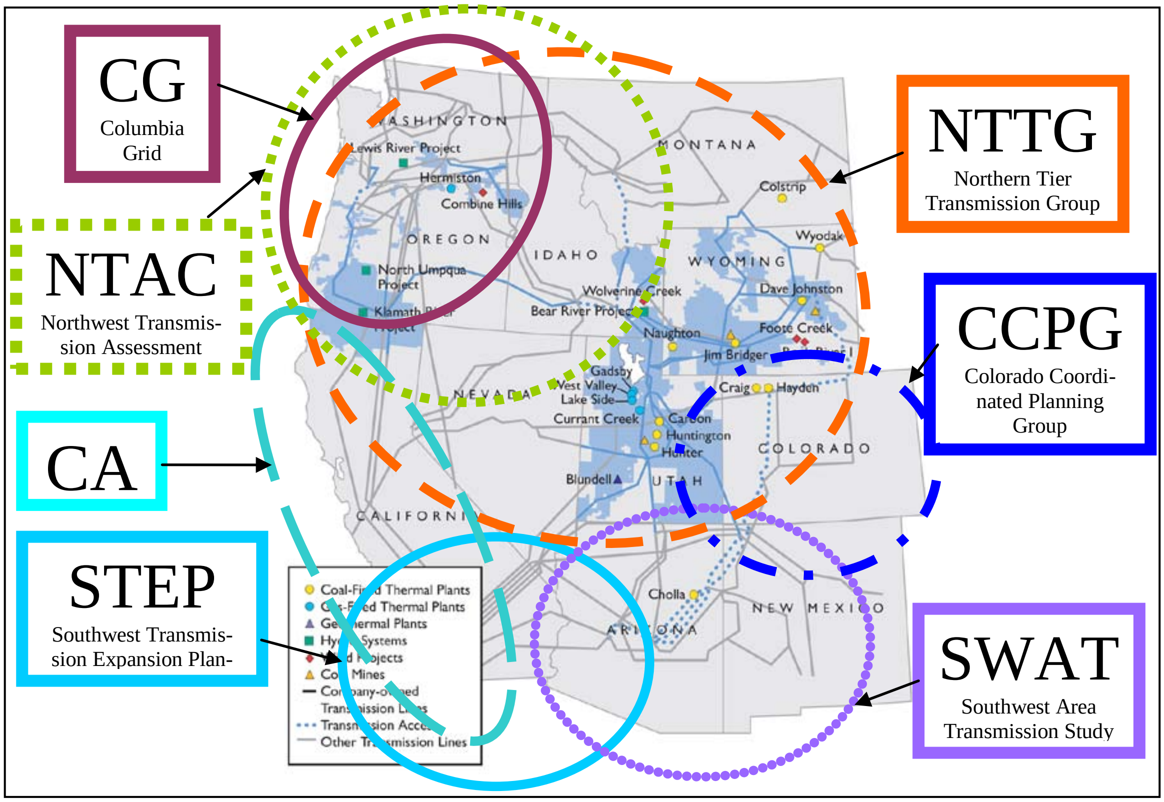
Recognizing that planning the entire western interconnection in one forum is impractical due to the overwhelming scope of work, a number of smaller sub-regional groups have been formed to address specific challenges in various areas of the interconnection. Generally all of these forums provide similar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

- **NTTG –** Northern Tier Transmission Group
- **CCPG –** Colorado Coordinated Planning Group
- **CG –** Columbia Grid
- **NTAC** - Northwest Transmission Assessment Committee
- **STEP** - Southwest Transmission Expansion Planning
- **SWAT –** Southwest Area Transmission Study
- **CA –** California Independent System Operator
- **WestConnect –** A southwest sub-regional planning group that includes participants from CCPG, SWAT and other utilities

PacifiCorp is one of the founding members of Northern Tier Transmission Group (NTTG). Originally formed in early 2007, NTTG has an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. The NTTG footprint includes approximately 2.7 million customers and more than 27,000 miles of transmission lines within Oregon, Washington, California, Idaho, Montana, Wyoming and Utah. In addition to PacifiCorp, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Idaho Power, Portland General Electric, and the Utah Associated Municipal Power Systems.

The geographical areas covered by these sub-regional planning groups are approximately shown in Figure 4.1 below:

Figure 4.1 – Sub-regional Transmission Planning Groups in the WECC



Energy Gateway

Since the last major transmission infrastructure construction in the 1970s and early 1980s, load growth and increased use of the western transmission system has steadily eroded the surplus capacity of the network. In the early 1990s when limited transmission capacity in high growth regions became more severe, low natural gas prices generally made adding gas fired generation close to load centers less expensive than transmission infrastructure additions. As natural gas prices started moving up in the year 2000, transmission construction became more attractive, but long transmission lead times to resource centers and rate recovery uncertainty suppressed new transmission investment.

Repeated sub-regional studies, including the Rocky Mountain Area Transmission Study dated September 2004, the Western Governor's Association Transmission Task Force Report dated May 2006 and the Northern Tier Transmission Group Fast Track Project Process in 2007 plus subsequent PacifiCorp planning studies concluded the critical need to alleviate transmission congestion and move transmission constrained energy resources to regional load centers.

The recommended bulk electric transmission additions for PacifiCorp took on a consistent footprint which is now known as Energy Gateway by establishing a triangle over Idaho, Utah and Wyoming with paths extending into Oregon and Washington.

Prior to 2007, PacifiCorp transmission activity was primarily focused on maintaining existing transmission reliability, executing queue studies, addressing compliance issues, and participating in shaping regional policy issues. Investments in main grid assets for load service, regional expansion or economic expansion to meet specific customer requests for service were addressed as transmission customers requested service.

New Transmission Requirements

Historically, transmission planning took place at the utility level and was focused on connecting specific utility generation resources to designated load centers. Under 888/889 Federal Energy Regulatory Commission rules, customer requests for transmission service were sporadic and uncoordinated with high levels of uncertainty in many markets which inhibited transmission investments.

Due to PacifiCorp's transmission system being a major component of the Western Interconnection, the Company has the responsibility to provide network customers adequate transmission capability that optimizes generation resources and provides reliable service both today and into the future. Based on current projections, loads and the dynamic blend of energy resources are expected to become more complex over the next twenty years which will challenge the existing capabilities of the transmission network.

In addition to ensuring sufficient capacity is available to meet the needs of its network customers, the Federal Energy Regulatory Commission in Order 890 encourages transmission providers such as PacifiCorp to plan and implement regional solutions for transmission reliability and expansion.

Based on the aggregate needs of PacifiCorp and others utilities in various sub-regional planning groups, a blueprint for transmission expansion was developed. The expansion plan is a culmination of prior studies and multiple utilities' integrated resource plans (PacifiCorp, Idaho Power, NorthWestern, and Portland General Electric) as well as identified potential plans of independent resource developers. It identifies a transmission expansion plan that will support multiple load centers, resource locations and resource types. In total the expansion plan, now referred to as Energy Gateway calls for the construction of numerous transmission segments – totaling approximately 2,000 miles.

The Energy Gateway blueprint uses a "hub and spoke" concept to most efficiently integrate transmission lines and collection points with resources and loads centers aimed at serving PacifiCorp customers while keeping in sight Regional and Sub Regional needs.

In addition to regulatory requirements for regional planning, future siting and permitting of new transmission lines will require significant participation and input from many stakeholders in the west. As part of new transmission line permitting PacifiCorp will have to demonstrate that several key requirements have been met; 1) the Company has satisfied an ongoing requirement for transmission to serve customers, 2) the Company is planning and building for the future and is obtaining corridors and mitigating environmental impacts prudently, and 3) that any projects being proposed economically meet the reliability and infrastructure needs of the region over all. This regional process and the Western Electricity Coordinating Council's planning process are considered critical to gaining wide support and acceptance for PacifiCorp's transmission expansion plan.

Reliability

PacifiCorp's transmission network is increasingly measured against new Federal Energy Regulatory Commission (FERC) / National Electric Reliability Corporation (NERC) mandatory reliability standards which require infrastructure to be in place in case of unplanned outage events. Mandatory compliance with the NERC planning standards is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment.[20] The majority of these new mandatory standards are the responsibility of the transmission owner.

NERC Planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy means the electric system needs to be able to supply aggregate electrical demand for customers at all times. Security means the electric system must withstand sudden disturbances or unanticipated loss of system elements.[21] Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

The ability to recover from system disturbances impacting main grid transmission often require accommodating multiple contingency scenarios which Energy Gateway helps facilitate along with other system reinforcement projects. There have been a number of main grid transmission outages in the latter part of 2007 resulting in curtailment of schedules, curtailments of interruptible loads and generation curtailments. These outages occurred on main grid paths and the ability to recover was severely limited because mitigation measures were electrically restricted due to lack of transmission capacity.

Resource Locations

As an extension of the 'hub and spoke' strategy, PacifiCorp must consider logical resource locations for the long-term based on environmental constraints, economical generation resources, and federal and state energy policies. PacifiCorp's primary energy resources in descending order are located in Utah, Wyoming, desert southwest and the west. Energy Gateway leverages the dynamic and future mix of energy resources and market access points at key locations and supports the Company's preferred resource portfolio.

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[20] Western Electricity Coordinating Council Reliability Criteria

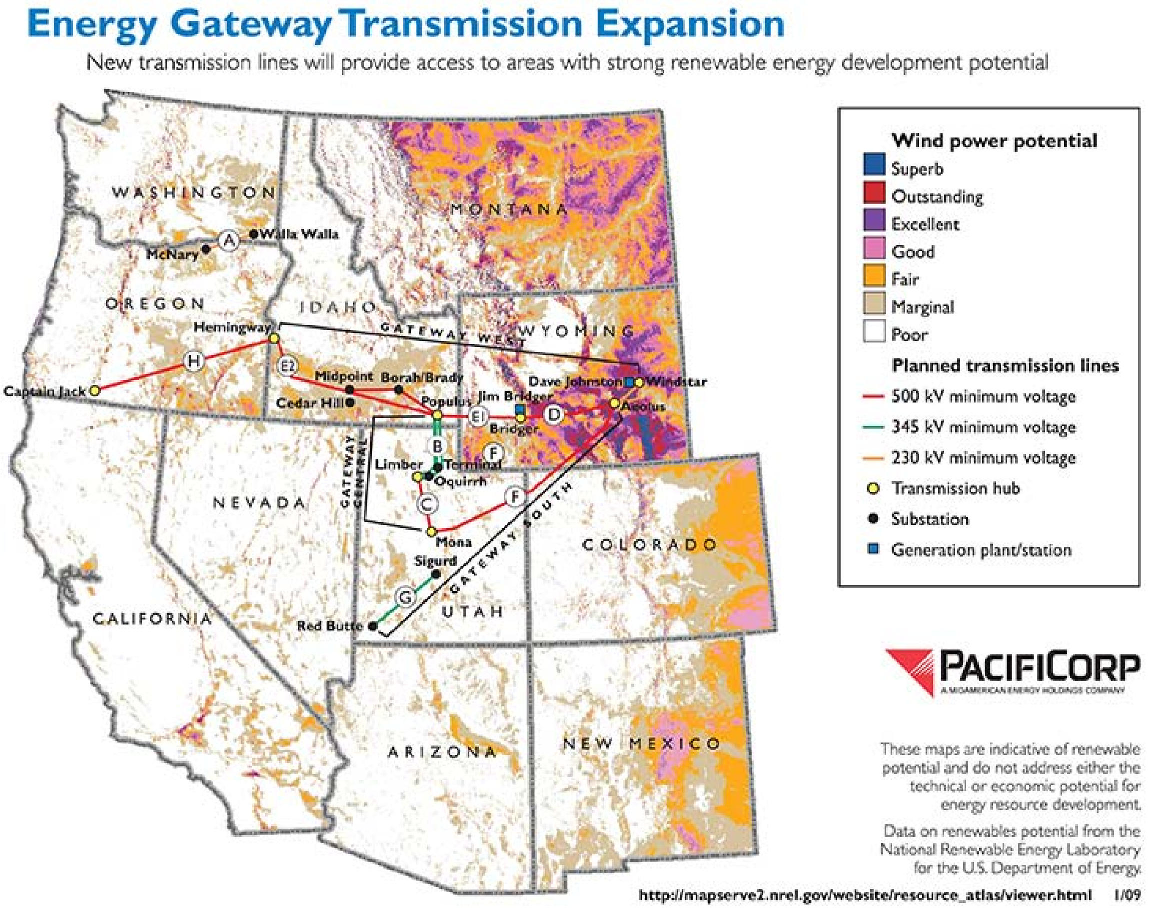
[21] Western Electricity Coordinating Council Reliability Criteria

Energy Gateway anticipates the availability and/or development of new resources including renewable energy resources in each of these key areas. The combination of resources cited in the 2008 IRP action plan and Energy Gateway support building to these resource locations.

As a complement to the 'hub and spoke' concept, the Western Governors Association has been developing a process for identifying western renewable energy zones (WREZ). These renewable energy zones would be used to facilitate needed infrastructure to integrate and deliver large volumes of renewable energy to the west. Energy Gateway is well positioned access key renewable energy zones, primarily in Wyoming. The geographical areas for wind power potential are approximately shown in Figure 4.2 below.

Figure 4.2 – Western States Wind Power Potential Up to 25,000 Megawatts

(Class 5 Wind Locations or Higher)



These maps are indicative of renewable potential and do not address either the technical or economic potential for energy resource development.

Data on renewables potential from the National Renewable Energy Laboratory for the U.S. Department of Energy.

http://mapserve2.nrel.gov/website/resource_atlas/viewer.html 1/09

As another indicator of the importance of Energy Gateway to customers and the region, the Department of Energy sponsored a study through Idaho National Laboratories to assess the economic impact of not building transmission on the Pacific Northwest. The report was published in July 2008 and references:

> *"The model indicates that the PNWER (Pacific Northwest Economic Region) has a potential economic loss of $15B to $25B annually and 300,000 to 450,000 jobs over 30 years if just the one infrastructure transmission line project with the greatest economic impact is not built (i.e., BC to NorCal), and upwards of $55B to $85B annually and 1,750,000 jobs over 30 years if the five transmission line projects of greatest economic impact are not built (i.e., Alberta to PacNW Project, BC to NorCal,* ***Gateway West****, Southern Xing & I-5 Corridor Projects, and Mountain States Intertie). These transmission line projects … transport bulk power and are considered critical for access to preferred electrical generation by areas with high economic development and growth. Note, however, that even if these five projects come to fruition, the added power will not adequately serve the projected PNWER population increase, assuming consumption habits remain the same".*[22]

> *"Preliminary engineering review and analysis of planned transmission projects within the PNWER region resulted in the following initial ranking of the projects based on estimates of potential economic value of each project, the likelihood of project execution, the resource area(s) being accessed, the size of the project, and the value of the project to the transmission system as a whole. This analysis was subjective in nature and conducted for comparison purposes only before the full economic analysis and ranking was performed. This ranking was partially based on project listings in the IRPs, knowledge of potential generation resource areas and load centers, areas of transmission need, etc. As stated above, this report ranks evaluated projects according to the INL's assessment of their overall economic impact to PNWER according to the specific factors used in the evaluation. Other analyses may place different emphasis on different factors, resulting in a different overall ranking of projects. Despite these potential differences, all of the projects are considered valuable and necessary to adequately address growing electric power needs. The INL's preliminary ranking is shown in Table 1:*[23]

Table 1. Preliminary Ranking of Transmission Projects

#	*Preliminary Rank Project Name*	*#*	*Preliminary Rank Project Name*
1	*BC to NorCal*	9	*Inland Project (WY to Las Vegas)*
2	*Alberta to PacNW Project*	10	*Inland Project (MT to Las Vegas*
3	*Gateway West –* ***PacifiCorp***	11	*McNary – John Day*
4	*Southern Crossing*	12	*Southwest Intertie Project (SWIP) North*
5	*Gateway South –* ***PacifiCorp***	13	*Alstom to San Francisco Bay project (Alaska to Alstom project not included)*
6	*Gateway Central –* ***PacifiCorp***	14	*Montana Alberta Tie*
7	*Mountain States Intertie*	15	*Port Angeles-Juan de Fuca"*
8	*Interstate 5 Corridor Lines*		

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[22] Idaho National Laboratory: The Cost of Not Building Transmission, page vi

[23] Idaho National Laboratory: The Cost of Not Building Transmission, page 5

ENERGY GATEWAY PRIORITIES

The greater part of the Energy Gateway project originates in Wyoming and Utah and migrates west to Oregon and Washington and south to southern Utah and Nevada. The Energy Gateway project takes into account the existing 2006 transaction commitments which include transmission facilities from southern Idaho to northern Utah (Path C), Mona to Oquirrh and Walla Walla to McNary.

PacifiCorp is actively pursuing the Energy Gateway transmission project under the following overarching key objectives:

- **Network customer driven –** Energy Gateway is primarily driven by PacifiCorp's retail and network customers' needs. Including Energy Gateway as a base allows PacifiCorp to move forward with the knowledge that over the coming years, transmission lines will be utilized to their fullest potential.
- **Support multiple resource scenarios –** The transmission expansion project must be able to accommodate a variety of future resource scenarios including meeting renewable portfolio standards, supporting natural gas fueled combustion turbines and market purchases, and recognizing that clean coal-based generation may re-emerge as a viable resource.
- **Consistent with past and current regional plans –** The proposed projects are consistent with a number of regional planning efforts. The need to expand transmission capacity has been known for years and should not be a surprise to the regional planning process and justification of need. The regional planning process should reduce the number of parties that may be publicly opposed to these projects due to the scrutiny placed on justification.
- **Get it built –** A significant barrier to achieving "steel in the ground" has historically been frustrated by lengthy multi-party negotiations related to planning and governance structure. Minimizing the impacts of these barriers through action-oriented objectives will be key to project success.
- **Secure the support of state and federal utility commissions for rate recovery –** Throughout the process, the project will seek input of state and federal regulators to ensure concerns are communicated early and addressed. The project should be undertaken in a manner that is acceptable to commissions and customers.
- **Protect the investment to the benefit of customers –** An appropriate balance must be struck to ensure that network customers do not subsidize third party use and ensure that PacifiCorp's long-term network allocation requirements are retained.

Phasing of Energy Gateway

PacifiCorp has been clear in its position regarding the initial announcement of Energy Gateway that significant infrastructure of new transmission capacity is needed to adequately serve PacifiCorp's existing and future loads over the long-term. The Company's position has not changed in this regard and requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South) of new transmission capacity to adequately serve its customers load and growth needs for the long-term.

PacifiCorp also recognized in its originally announced Energy Gateway Program the need and benefits of potentially “upsizing or scaling up” the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors, potential to reduce environmental impacts, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity.

PacifiCorp still believes there are viable expectations and reasons for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp believes that both short-term and long-term benefits exist as a result of upsizing the Energy Gateway Program and that existing barriers may be overcome at some future date. However; the Company must prudently move ahead now with steps necessary to serve its customers while keeping in sight these potential benefits perceived by upsizing.

PacifiCorp is proceeding with efforts regarding planning and rating requirements for the Energy Gateway Program which facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need and construction timing

The core transmission expansion plan will construct lines and stations required to deliver 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) of transmission capacity required to meet PacifiCorp’s long-term regulatory requirement to serve loads. Additional stages may continue at some future date as determined by, economic, business and regulatory drivers that may be better defined in the upcoming years. Further expansion to the Desert Southwest will also be considered.

Each segment will be justified individually within the overall program. A combination of benefits including net power cost savings derived from the IRP, reliability, capital offsets for renewable resource development in low yield geographic regions and system loss reductions will be used to assess the viability of each segment.

The primary justification due to net power cost savings is derived from modeling alternative resource options under an assortment of forecast assumptions with and without Energy Gateway. The difference between the Energy Gateway build options and no transmission expansion yields a net power savings. Additional considerations listed above are considered on a segment-by-segment basis.

Each Energy Gateway segment will be reviewed again before significant commitments are made to ensure its justification. Therefore, depending on conditions or alternatives certain segments could be deferred or not constructed if not warranted. It is also reasonable to expect certain core segments will be justified in multiple scenarios. Segments will be reevaluated during each IRP cycle and annual business plan similar to generation/market resource plans to ensure they are required.

5. RESOURCE NEEDS ASSESSMENT

INTRODUCTION

This chapter presents PacifiCorp's assessment of resource need, focusing on the first 10 years of the IRP's 20-year study period, 2009 through 2018. The Company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicated when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

LOAD FORECAST

Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques. These models are driven by county and state level forecasts of employment and income that are provided by public agencies or purchased from commercial econometric forecasting services.[24] Appendix E provides additional details on the state-level forecasts.

Evolution and changes in Integrated Resource Planning Load Forecasts

Through the course of the 2008 integrated resource planning cycle, PacifiCorp relied on the November 2008 load forecast for the development of the load and resource balance and portfolio evaluations. Portfolio analysis started as early as June 2008 with preliminary load forecast and continued through December 2008. Under stable economic conditions, the Company would normally prepare one load forecast per year. However, the unstable and volatile economic conditions required the Company to update its load forecasts frequently to attempt to capture price and usage changes between June 2008 and November 2008. Because of the magnitude of the forecast changes and the Company's plan to align IRP filing with the Business Plan, the Company decided that it was prudent to incorporate latest load forecast updates in the IRP. Consequently, PacifiCorp's IRP analysis from November 2008 onward reflects the November 2008 load forecast.

In order to improve sales and load forecasting methods, capabilities, and accuracy, several improvements in the load forecasting approach were identified jointly by the Company and the Company's consultant, ITRON, and the load forecast methodology was changed to incorporate these improvements. Forecast improvements were driven primarily by six major changes in forecast assumptions. First, load research data was used to model the impact of weather on monthly retail sales and peaks by state by class. The Company collects hourly load data from a sample of customers for each class in each state. These data are primarily used for rate design, but they also

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

provide an opportunity to better understand usage patterns, particularly as they relate to changes in temperature. The greater frequency and data points associated with this hourly data make it better suited to capture load changes driven by changes in temperature than the monthly data used in the Company's prior forecasts.

Second, the time period used to define normal weather was updated from the National Oceanic and Atmospheric Administration's 30-year period of 1971-2000 to a 20-year time period of 1988-2007. The Company identified a trend of increasing summer and winter temperatures in the Company's service territory that was not being captured in the thirty year data. ITRON surveys have identified that many other utilities are also using more recent data for determining normal temperatures. Based on this review and on the recommendation from ITRON, the Company adopted a 20-year rolling average as the basis for determining normal temperatures. This better captures the trend of increasing temperatures observed in both summer and winter.

Third, the historical data period used to develop the monthly retail sales forecasts was updated to cover 1997-2007.

Fourth, monthly peaks were forecasted for each state using a peak model and estimated with historical data from 1990-2007. As an improvement to the forecasting process, the Company developed a model that relates peak loads to the weather that generated the peaks. This model allows the Company to better predict monthly and seasonal peaks. The peak model is discussed in greater detail in the following section.

Fifth, system line losses were updated to reflect actual losses for the 5-years ending December 31, 2007. The Company previously used the results of the most recent system line loss study, which was based on calendar-year 2001 data. The Company had observed that actual losses were higher than those from the previous line loss study. Investigation and discussions with the consultant who prepared the previous line loss study indicated that the previous study only reflected losses associated with retail load. Because there are also system losses associated with wholesale sales, the prior loss value was understated. The use of actual losses is a reasonable basis for capturing total system losses and has been incorporated in this forecast.

Finally, analyses were performed and adjustments made for the impact of current economic conditions. Because the model is estimated over a period of relative prosperity, it is necessary to make an explicit adjustment for the economic downturn, and hence the forecast was revised. In October 2008, the near-term forecast was adjusted downward to reflect the recent recession impacts mirroring load changes experienced in the previous recession (2001-2002). In the November update, the forecast was further adjusted downward in the Industrial sector for Utah (2010 onwards) and Wyoming (2009 onwards) to reflect the additional recession impacts.

In addition to these forecast methodology changes, energy efficiency (Class 2 DSM) was handled differently relative to past IRPs. Rather than treating Class 2 DSM as a decrement to the load forecast, PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model. To accomplish this, the load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM. The capacity expansion model then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by using the capacity expansion model, determines the cost-effective mix of Class 2 DSM for a given scenario. For retail load forecast reporting, PacifiCorp deducts the Class 2 DSM load reductions reflected in the 2008 IRP preferred portfolio from the original “pre-DSM” load forecast.

Modeling overview

The following section describes the modeling techniques used to develop the load forecast.

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential, commercial, irrigation, public street lighting, and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers.

The residential use-per-customer is forecasted by statistical end-use forecasting techniques. This approach incorporates end use information (saturation forecasts and efficiency forecasts) but is estimated using monthly billing data. Saturation trends are based on analysis of the Company’s saturation survey data and efficiency trends are based on EIA forecasts that incorporate market forces as well as changes in appliance and equipment efficiency standards. Major drivers of the statistical end use based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

The commercial, irrigation, public street lighting, and sales to public authority use-per-customer forecast is developed using an econometric model. For the commercial class, sales per customer are forecasted using regression analysis techniques with non-manufacturing employment serving as the major economic driver in addition to weather related variables. For other classes, sales per customer are forecasted through regression analysis techniques using time trend variables.

The customer forecasts are generally based on a combination of regression analysis and exponential smoothing techniques using historical data from 1997 to 2007. For the residential class, the customer forecasts are developed using a regression model with Global Insight’s forecast of the states’ number of households serving as the major driver. For the commercial class, forecasts rely on a regression model with the forecasted residential customer numbers being used as the major driver. For other classes (irrigation, street lighting, and public authority), customer forecasts are developed based on exponential smoothing models.

The industrial sales forecast is developed for each jurisdiction using a model which is dependent on input for the Customer Account Managers (CAMs). The industrial customers are separated into three categories: existing customers that are tracked by the CAMs, new large customers or expansions by existing large customers, and industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if (1) they have a peak load of five MW or more or if (2) they have a peak load of one MW or more and have a history of large variations in their monthly usage. The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer. The account managers have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Projected loads associated with new customers or expansions of existing large customers are categorized into three groups. Tier 1 customers are those with a signed master electric service agreement ("MESA") or engineering material and procurement agreement ("EMPA"). When a customer signs a MESA or EMPA, this contractually commits the Company to provide services under the terms of agreement. Tier 2 includes customers with a signed engineering services agreement (ESA). This means that customer paid the Company to perform a study that determines what improvements the Company will need to make to serve the requested load. Tier 3 consists of customers who made inquiries but have not signed a formal agreement. Projected loads from customers in each of these tiers are assigned probabilities depending on project-specific information received from the customer.

Smaller industrial customers are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment serves as the major economic driver. The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories. The segments are forecasted differently within the industrial class because of the diverse makeup of the customers within the class.

After monthly energy by customer class is developed, hourly loads are estimated in two steps. First, PacifiCorp derives monthly and seasonal peak forecasts for each state. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables. These weather variables include the average temperature on the peak day and average daily temperatures for two days prior to the peak day. Second, hourly load forecasts for each state are obtained from the hourly load models using state-specific hourly load data and daily weather variables. Hourly load forecasts are developed using a model that incorporates the 20-year average temperatures, the actual weather pattern for a year, and day-type variables such as weekends and holidays. The model uses HDD (heating degree days) and CDD (cooling degree days) values for each of the twenty years and averages the results using a Rank and Average method instead of averaging by date as in the previous thirty-year process. This helps to incorporate both mild and extreme days in weather patterns, thereby more effectively representing the daily volatility in weather experienced during a typical year. Also, the method preserves the extreme temperatures and maps them to a year to produce a more accurate estimate of daily temperatures. The hourly load forecasts are adjusted for line losses and calibrated to monthly and seasonal peaks. After PacifiCorp develops the hourly load forecasts for each state, hourly loads are aggregated to the total Company system level. System coincident peaks are then identified as well as the contribution of each jurisdiction to those monthly system peaks.

The following sections describe the November 2008 energy and coincident peak load forecasts used for IRP portfolio modeling.

Energy Forecast

Table 5.1 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the forecast period 2009 through 2018.

Table 5.1 – Forecasted Average Annual Energy Growth Rates for Load

	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009-2018	2.1%	1.2%	0.7%	1.6%	2.5%	3.4%	1.5%	1.5%

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% percent annually from fiscal year 2009 to 2018. Table 5.2 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

Table 5.2 – Annual Load Growth forecasted (in Megawatt-hours) 2009 through 2018

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**61,558,392**	15,475,197	4,481,972	1,006,036	24,211,643	10,077,831	3,746,722	2,558,992
2010	**62,572,227**	15,488,359	4,490,263	1,036,284	24,766,082	10,422,330	3,784,242	2,584,666
2011	**63,979,543**	15,733,361	4,528,860	1,072,927	25,331,349	10,873,984	3,825,481	2,613,580
2012	**65,860,922**	16,096,835	4,564,434	1,108,124	26,227,765	11,341,534	3,875,330	2,646,900
2013	**67,602,494**	16,395,770	4,586,107	1,119,431	26,990,389	11,738,006	4,024,940	2,747,851
2014	**69,299,539**	16,648,638	4,620,452	1,128,072	27,811,230	12,117,111	4,142,098	2,831,937
2015	**70,735,798**	16,790,823	4,652,542	1,136,689	28,631,507	12,498,120	4,172,873	2,853,245
2016	**72,193,764**	16,979,579	4,692,854	1,148,202	29,355,209	12,926,718	4,211,552	2,879,649
2017	**73,110,441**	17,080,573	4,709,745	1,153,152	29,791,003	13,240,453	4,237,529	2,897,985
2018	**74,348,970**	17,281,372	4,752,289	1,165,356	30,363,899	13,581,557	4,278,351	2,926,146
Average Annual Growth Rate								
2009-18	**2.1%**	**1.2%**	**0.7%**	**1.6%**	**2.5%**	**3.4%**	**1.5%**	**1.5%**
2018-28	**1.2%**	**1.1%**	**0.9%**	**1.1%**	**1.6%**	**0.6%**	**0.9%**	**0.9%**
2009-28	**1.6%**	**1.2%**	**0.8%**	**1.3%**	**2.0%**	**1.9%**	**1.2%**	**1.2%**

System-Wide Coincident Peak Load Forecast

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

In the 1990's the annual system peak usually occurred in the winter. After 2000, the annual system peak has generally occurred in the summer. The system peak has switched to the summer as a result of several factors. First, the increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter has contributed to shift from a winter peak to a summer peak. This trend in space conditioning is expected to continue. Second, Utah with a summer peak that is relatively higher than the winter peak has been growing faster than the system. This growth also has contributed to a shift from a winter peak to a summer peaking system.

Total system load factor is expected to be relatively stable over the 2009 to 2018 time period. There are several factors working in opposite directions, leading to this result. First, the relatively high growth in high load factor industrial sales, particularly in Wyoming, tends to push up the system load factor. Second, as discussed above, the shift in space conditioning tends to push down the system load factor. And, third, efficiency standards such as the 2012 federal lighting standards also tend to push down the system load factor.

Table 5.3 – Forecasted Coincidental Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009-2018	**2.4%**	**1.6%**	**1.8%**	**1.9%**	**2.6%**	**3.1%**	**2.5%**	**3.0%**

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.7 percent and 1.6 percent, respectively, over the forecast horizon.

Table 5.4 below shows that for the same time period the total peak is expected to grow by 2.4 percent.

Table 5.4 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**10,143**	2,463	761	167	4,509	1,253	628	362
2010	**10,360**	2,476	768	174	4,626	1,290	654	372
2011	**10,631**	2,526	780	181	4,708	1,354	682	401
2012	**10,978**	2,579	816	187	4,854	1,394	716	431
2013	**11,261**	2,638	800	190	5,008	1,440	748	437
2014	**11,451**	2,695	815	189	5,174	1,485	691	402
2015	**11,730**	2,728	826	191	5,322	1,530	718	414
2016	**12,032**	2,763	836	194	5,458	1,577	759	446
2017	**12,251**	2,795	846	199	5,568	1,616	773	454
2018	**12,522**	2,836	889	197	5,686	1,656	786	473
Average Annual Growth Rate								
2009-2018	**2.4%**	**1.6%**	**1.8%**	**1.9%**	**2.6%**	**3.1%**	**2.5%**	**3.0%**
2018-2028	**1.4%**	**1.4%**	**1.1%**	**1.2%**	**1.8%**	**0.7%**	**0.9%**	**0.6%**
2009-2028	**1.9%**	**1.5%**	**1.4%**	**1.5%**	**2.2%**	**1.9%**	**1.7%**	**1.8%**

One noticeable aspect of the states contribution to the system coincidental peak forecast is that they do not smoothly increase from year to year, and in Idaho, the contribution to system coincident peak decreases in 2014.

Idaho's contribution to the coincident peak is forecasted to decrease in 2014 even though the total system peak increases from year to year. This behavior occurs because state level coincident peaks do not occur at the same time as the system level coincident peak, and because of differences among the states with regard to load growth and customer mix. While each state's peak load is forecast to grow each year when taken on its own, its contribution to the system coincident peak will vary since the hour of system peak does not coincide with the hour of peak load in each state. As the growth patterns of the class and states change over time, the peak will move within the season, month or day, and each state's contribution will move accordingly, sometimes resulting in a reduced contribution to the system coincident peak from year to year in a particular state. This is seen in a few areas in the forecast as well as experienced in history. For example, the Idaho state load is driven in the summer months by the activity in the irrigation class. The planting and irrigating practices usually cause this state to experience the maximum load in late June or early July. This load then quickly decreases week by week. Consequently, there can be as much as 300 MW of load difference between the maximum load and the loads during the last weeks of July.

Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different patterns than the system coincident hourly load. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. Table 5.5 reports the jurisdictional peak demand growth over the forecast horizon.

Table 5.5 – Jurisdictional Peak Load forecast, 2009 through 2018 (Megawatts)

Year	OR	WA	CA	UT	WY	ID	SE-ID
2009	2,781	850	187	4,678	1,343	776	434
2010	2,795	856	197	4,796	1,371	785	448
2011	2,825	863	204	4,875	1,419	795	453
2012	2,854	876	210	5,033	1,473	806	485
2013	2,914	884	212	5,202	1,532	835	491
2014	2,958	897	214	5,360	1,581	858	497
2015	2,989	909	216	5,522	1,631	867	493
2016	3,010	919	218	5,662	1,680	874	511
2017	3,033	931	221	5,775	1,729	881	518
2018	3,059	942	223	5,902	1,776	890	536
Average Annual Growth Rate							
2009-2018	**1.1%**	**1.1%**	**2.0%**	**2.6%**	**3.2%**	**1.5%**	**2.4%**
2018-2028	**1.3%**	**1.4%**	**1.2%**	**1.8%**	**0.7%**	**0.9%**	**0.9%**
2009-2028	**1.2%**	**1.3%**	**1.6%**	**2.2%**	**1.8%**	**1.2%**	**1.6%**

EXISTING RESOURCES

For the forecasted 2009 summer peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 13,145 MW. Table 5.6 provides anticipated system peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2009.

Table 5.6 – Capacity Ratings of Existing Resources

Resource Type	MW *	Percent
Pulverized Coal	6,128	46.6%
Gas-CCCT	2,025	15.4%
Gas-SCCT	380	2.9%
Hydroelectric	1,450	11.0%
Class 1 DSM **	345	2.6%
Renewables	247	1.9%
Purchase ***	2,061	15.7%
Qualifying Facilities	271	2.1%
Interruptible	237	1.8%
Total	**13,145**	**100%**

* Represents the capacity available at the time of system peak.
** Class 1 Demand-side management is PacifiCorp’s dispatchable load control.
*** Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

In September 2008, the Chehalis combine cycle combustion turbine plant began operations adding 509 MW of summer peak capacity to the PacifiCorp thermal fleet. Table 5.7 lists existing PacifiCorp’s coal fired thermal plants and table 5.8 lists existing natural gas fired plants. As a modeling assumption, plant retirements were based on the Company’s 2007 depreciation study. The end of the depreciable life of Gadsby units 1-3 is currently 2017, while the depreciable life for Carbon units 1 and 2 is 2020. No thermal plants are currently scheduled for retirement. Plant retirement decisions will be based on an assessment of plant economics that considers the cost for replacement power given environmental compliance requirements, market conditions, and other factors.

Table 5.7 – Coal Fired Plants

Plant	PacifiCorp Percentage Share	State	Average Net Maximum Capacity
Carbon 1	100%	Utah	67.0
Carbon 2	100%	Utah	105.0
Cholla 4	100%	Arizona	395.0
Colstrip 3	10%	Montana	74.0
Colstrip 4	10%	Montana	74.0
Craig 1	19%	Colorado	82.5
Craig 2	19%	Colorado	82.5
Dave Johnston 1	100%	Wyoming	106.0
Dave Johnston 2	100%	Wyoming	106.0

Plant	PacifiCorp Percentage Share	State	Average Net Maximum Capacity
Dave Johnston 3	100%	Wyoming	220.0
Dave Johnston 4	100%	Wyoming	330.0
Hayden 1	24%	Colorado	45.1
Hayden 2	13%	Colorado	33.0
Hunter 1	94%	Utah	403.1
Hunter 2	60%	Utah	259.3
Hunter 3	100%	Utah	460.0
Huntington 1	100%	Utah	445.0
Huntington 2	100%	Utah	450.0
Jim Bridger 1	67%	Wyoming	353.3
Jim Bridger 2	67%	Wyoming	353.3
Jim Bridger 3	67%	Wyoming	353.3
Jim Bridger 4	67%	Wyoming	353.3
Naughton 1	100%	Wyoming	160.0
Naughton 2	100%	Wyoming	210.0
Naughton 3	100%	Wyoming	330.0
Wyodak	80%	Wyoming	268.0

Table 5.8 – Natural Gas Plants

Coal-fueled	PacifiCorp Percentage Share	State	Average Net Maximum Capacity
Currant Creek	100%	Utah	541
Gadsby 1	100%	Utah	60
Gadsby 2	100%	Utah	75
Gadsby 3	100%	Utah	100
Gadsby 4	100%	Utah	40
Gadsby 5	100%	Utah	40
Gadsby 6	100%	Utah	40
Hermiston 1 *	50%	Oregon	124
Hermiston 2 *	50%	Oregon	124
Lake Side	100%	Utah	544
Chehalis	100%	Washington	520

* Remainder of Hermiston plant under purchase contract by the Company for a total of 248 MW.

Renewables

PacifiCorp's renewable resources, presented by resource type, are described below.

Wind

PacifiCorp acquires wind power from owned plants and various purchase agreements. Since the 2007 IRP, PacifiCorp has acquired several large wind resources including Seven Mile I and II, and Marengo II, Glenrock I and III, and Rolling Hills. These projects came on line in 2008. The

Company also entered into 20-year power purchase agreements for the total output of several projects including Mountain Wind I and II and Spanish Fork in 2008, Duke Energy's (Three Buttes Windpower LLC) Campbell Hill project and Oregon Wind Farm I in 2009, and Oregon Wind Farm II in 2010.

Table 5.9 shows existing and firm planned wind facilities owned by PacifiCorp, while Table 5.10 shows existing wind power purchase agreements. For the year ended December 31, 2008, PacifiCorp's total installed wind capacity totaled 802 MW, along with 315 MW of purchased power capacity.

Table 5.9 – PacifiCorp-owned Wind Resources

Utility-Owned Wind Projects	Capacity (MW)	In-Service Year	State
Foote Creek I [1/]	33.0	2005	WY
Leaning Juniper	100.5	2006	OR
Goodnoe Hills East Wind	94.0	2007	WA
Marengo	140.4	2007	WA
Glenrock Wind I	99.0	2008	WY
Glenrock Wind III	39.0	2008	WY
Marengo II	70.2	2008	WA
Rolling Hills Wind	99.0	2008	WY
Seven Mile Hill Wind	99.0	2008	WY
Seven Mile Hill Wind II	19.5	2008	WY
High Plains (Under Construction)	99.0	2009	WY
TOTAL	**893.0**		

[1/] Net total capacity for Foote Creek I is 41 MW.

Table 5.10 – Wind Power Purchase Agreements

Power Purchase Agreements	Capacity (MW)	In-Service Year	State
Foote Creek III	25.2	2005	WY
Foote Creek IV	16.8	2005	WY
Wolverine Creek	64.5	2005	ID
Rock River I	50.0	2006	WY
Mountain Wind Power I	60.0	2008	WY
Mountain Wind Power II	79.5	2008	WY
Spanish Fork	18.9	2008	UT
Three Buttes Wind Power (Duke)	99.0	2009	WY
Oregon Wind Farm I	45.0	2009	OR
Oregon Wind Farm II	20.0	2010	OR
TOTAL	**478.9**		

PacifiCorp also has wind integration, storage and return agreements with Bonneville Power Administration, Eugene Water and Electric Board, Public Service Company of Colorado, and Seattle City Light.

Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007.

Biomass

Since the 2007 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples are found in Table 5.11.

Table 5.11 – Existing Biomass resources

Biomass Projects	Capacity (MW)	State
Biomass One, LLC	25.0	Oregon
Davis County Waste Management	1.6	Utah
Douglas Country Forest Products	6.25	Oregon
DR Johnson Lumber Company	8.3	Oregon
Evergreen BioPower	10.0	Oregon
Roseburg Forest Products	20.0	Oregon
Rough & Ready Lumber	1.28	Oregon
Simplot Phosphates, LLC	9.5	Wyoming

Biogas

Since the 2007 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples are found in Table 5.12.

Table 5.12 – Existing Biogas resources

Biogas Project	Capacity (MW)	State
Sunderland Dairy	0.15	Utah
Wadeland South, LLC	0.125	Utah
Weber County, State of Utah	0.95	Utah
Hill Air Force Base	2.5	Utah
Ballard Hog Farms Inc	0.05	Utah
George Deruyter & Sons Dairy	1.2	Washington
Finley BioEnergy	4.8	Oregon
Oregon Environmental Industries	3.2	Oregon

Solar

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

Hydroelectric Generation

PacifiCorp owns or purchases 1,450 MW of hydroelectric generation. These resources account for approximately 11 percent of PacifiCorp's total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. Hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

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

PacifiCorp has added approximately 5 MW of additional capacity to its hydroelectric portfolio since the release of the 2007 IRP. This additional capacity is found in Table 5.13.

Table 5.13 – Hydroelectric additions

Hydroelectric Project	Capacity (MW)	State
Bell Mountain Power	0.45	Idaho
City of Albany, Dept of Public Works	0.5	Oregon
Cottonwood Hydro	0.85	Utah
Curtiss Livestock	0.075	Oregon
Loyd Fery Farms	0.04	Oregon
Mountain Energy	0.05	Oregon
Roush Hydro, Inc	0.08	Oregon
Yakima Tieton	2.95	Washington

Table 5.14 provides an operational profile for each of PacifiCorp's hydroelectric generation facilities. The dates listed refer to a calendar year.

Table 5.14 – Hydroelectric Generation Facilities – Nameplate Capacity as of January 2009

Plant	PacifiCorp Share (MW)	State	License Expiration Date	Retirement Date
West				
Bigfork	4.15	Montana	2053	2053
Clearwater 1	15.00	Oregon	2038	2038
Clearwater 2	26.00	Oregon	2038	2038
Copco 1	20.00	California	2006	2046

Plant	PacifiCorp Share (MW)	State	License Expiration Date	Retirement Date
Copco 2	27.00	California	2006	2046
East Side	3.20	Oregon	2006	2016
Fish Creek	11.00	Oregon	2038	2038
Iron Gate	18.00	California	2006	2046
JC Boyle	97.98	Oregon	2006	2046
Lemolo 1	31.99	Oregon	2038	2038
Lemolo 2	33.00	Oregon	2038	2038
Merwin	136.00	Washington	2058	2058
Rogue	46.76	Oregon	Various	Various
Slide Creek	18.00	Oregon	2038	2038
Soda Springs	11.00	Oregon	2038	2038
Swift 1	240.00	Washington	2058	2058
Toketee	42.50	Oregon	2038	2038
West Side	0.60	Oregon	2006	2016
Yale	134.00	Washington	2058	2058
Small West Hydro*	18.11	CA/OR/WA	Various	Various
East				
Bear River	108.73	ID/UT	Various	Various
Small East Hydro**	33.85	ID/UT/WY	Various	Various

* Includes Bend, Condit, Fall Creek, and Wallowa Falls

** Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock.

Note: Operational Capacity may differ from Nameplate Capacity due to operating conditions.

Hydroelectric Relicensing Impacts on Generation

Table 5.15 lists the estimated impacts to average annual hydro generation from FERC license renewals. PacifiCorp assumed that all hydroelectric facilities currently involved in the relicensing process will receive new operating licenses, but that additional operating restrictions imposed in new licenses, such as higher bypass flow requirements, will reduce generation available from these facilities.

Table 5.15 – Estimated Impact of FERC License Renewals on Hydroelectric Generation

Year	Lost Generation (MWh)
2009	160,356
2010	160,356
2011	160,356
2012	195,560
2013	195,560
2014	195,560
2015	338,917

Year	Lost Generation (MWh)
2016	415,328
2017	415,328
2018	413,435
2019	415,566
2020	415,566
2021	415,566
2022	415,566
2023	415,566
2024	415,566
2025	415,566
2026	415,566
2027	415,566
2028	415,566

Note: Excludes the decommissioning of Condit, Cove, Powerdale, and American Fork.

Demand-side Management

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

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

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

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

- **Class 4 DSM: Resources from energy efficiency education and non-incentive based voluntary curtailment programs/communications/pleas –** Class 4 programs resources may be in the form of energy and/or capacity reductions. The reductions are typically achieved from voluntary actions taken by customers, behavior changes, to save energy and/or reduce costs, benefit the environment or in response to public or utility company pleas to conserve or shift their usage to off peak hours. Program savings are difficult to measure and in many cases tend to vary over time. While not specifically relied upon in resource planning, Class 4 savings appear in historical load data therefore into resource planning through the plan load forecasts. The value of Class 4 DSM is long-term in nature. Class 4 programs help foster an understanding and appreciation as to why utilities seek customer participation in Class 1, 2 and 3 programs, as well provide a foundational understanding of how to use energy wisely. Program examples include Utah's PowerForward program, Company brochures with energy savings tips, customer news letters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Do the bright thing" and "Let's turn the answers on". Studies have shown potential savings up to 15% from behavior changes[25], especially when coupled with complimentary DSM programs to assist customers with a portion of the actions taken.[26] Although these behavior savings are often difficult and costly to track and measure, enough studies have measured their effects to expect at least a very modest degree of savings (equal to or greater than those expected to be acquired through DSM programs; e.g. 1+%) to be realized and reflected in customer usage and future load forecasts.

PacifiCorp has been operating successful DSM programs since the late 1980s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the Company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Company investments continue to increase year on year with 2008 investments exceeding $76

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[25] Lynn Fryer Stein, "California Information Display Pilot Technology Assessment" (December 2004), prepared by Primen Inc., for Southern California Edison.

[26] John Green and Lisa A. Skumatz, "Evaluating the Impacts of Education/Outreach Programs: Lessons on Impacts, Methods and Optimal Education, "paper presented at the American Council for an Energy Efficient Economy summer Study on Energy Efficiency in Buildings (2000).

million (all states). Work continues on the expansion of program portfolios in the states of Utah, Washington, Idaho and California. In late 2008 the Company received approval to begin offering DSM programs to Wyoming customers beginning in January 2009. In Oregon the Company is working closely with the Energy Trust of Oregon on helping to identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and Company support in pursuit of DSM resource targets.

The following represents a brief summary of the existing resources by class.

Class 1 Demand-side Management

Currently there are four Class 1 programs running across PacifiCorp's six state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program; Idaho's and Utah's scheduled firm irrigation load management programs; Idaho's and Utah's dispatchable irrigation load management programs; and special contract curtailment agreements with large business customers. In 2008 the programs provided approximately 560 megawatts of Class 1 DSM program resources during the highest summer peak load hours.

Class 2 Demand-side Management

The Company currently manages thirteen distinct Class 2 products, many of the products are offered in multiple states. In all, the combination of Class 2 programs across the Company's six state service area total thirty-four. The cumulative historical energy and capacity savings (1992-2008) associated with Class 2 DSM program activity has accounted for nearly 3.4 million megawatt hours and over 600 megawatts of load reductions.

Class 3 Demand-side Management

The Company has numerous Class 3 programs currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted rates (Utah), residential year-around inverted rates (California, Oregon, and Washington) and Energy Exchange programs (Oregon, Utah, Idaho, Wyoming and Washington). Savings associated with these programs are captured within the Company's load forecast, with the exception of the more immediate call-to-action programs like Energy Exchange and Utah's PowerForward programs. The impacts of these programs are thus captured in the integrated resource planning framework. Energy Exchange and Utah's PowerForward are examples of Class 3 programs relied upon as reliability resources as opposed to base resources. System-wide participation in metered time-of-day and time-of-use programs as of December 31, 2008 was about 21,700 customers, up from about 21,200 in 2006. Approximately 1.28 million residential customers—89% of the Company's residential customer base—are currently subject to inverted rate plans either seasonally or year-around.

PacifiCorp continues to evaluate Class 3 programs for applicability to long-term resource planning. As discussed in Chapter 6, five additional programs were provided as resource options in preliminary IRP modeling scenarios.

Class 4 Demand-side Management

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts, bill messages, newsletters, school education programs, and personal contact. Specific firm load reductions due to Class 4 DSM activity will show up in Class 2 DSM program results and non-program/documented reductions in the load forecast over time.

Table 5.16 summarizes the existing DSM programs, and describes how they are accounted for as planned resources.

Table 5.16 – Existing DSM Summary, 2009-2018

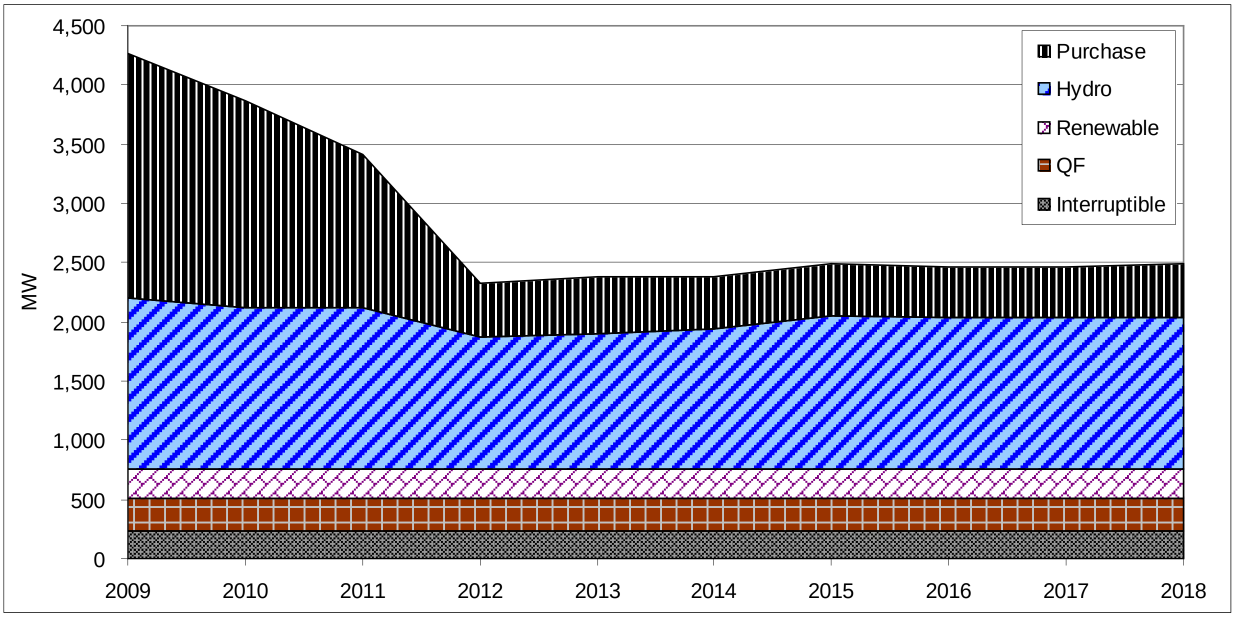
Program Class	Description	Energy Savings or Capacity at Generator	Included as Base Resources for 2009-2018 Period
1	Residential/small commercial air conditioner load control	100 MW summer peak	Yes
	Irrigation load management	220 MW summer peak	Yes
	Interruptible contracts	237 MW	Yes
2	Company and Energy Trust of Oregon programs	483 MWa and 908 MW (2008 IRP selections)	Yes
3	Energy Exchange	0-37 MW (assumes no other Class 3 competing products running)	No, leveraged as economic and reliability resource dependent on market prices/system loads
	Time-based pricing	MWa/MW unavailable 22.,000 customers	No, historical behavior captured in load forecast
	Inverted rate pricing	MWa/MW unavailable 1.28 million residential	No, historical behavior captured in load forecast
4	PowerForward	0-80 MW summer peak	No, leveraged as economic and reliability resource dependent on market prices/system loads
	Energy Education	MWa/MW unavailable	No, captured in load forecast over time and other Class 1 and Class 2 program results

Power Purchase Contracts

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

Figure 5.1 presents the contract capacity in place for 2008 through 2018 as of January 2009. As shown, major capacity reductions in purchases and hydro contracts occur. (For planning purposes, PacifiCorp assumes that current qualifying facility and interruptible load contracts are extended to the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 5.1 – Contract Capacity in the 2008 Load and Resource Balance

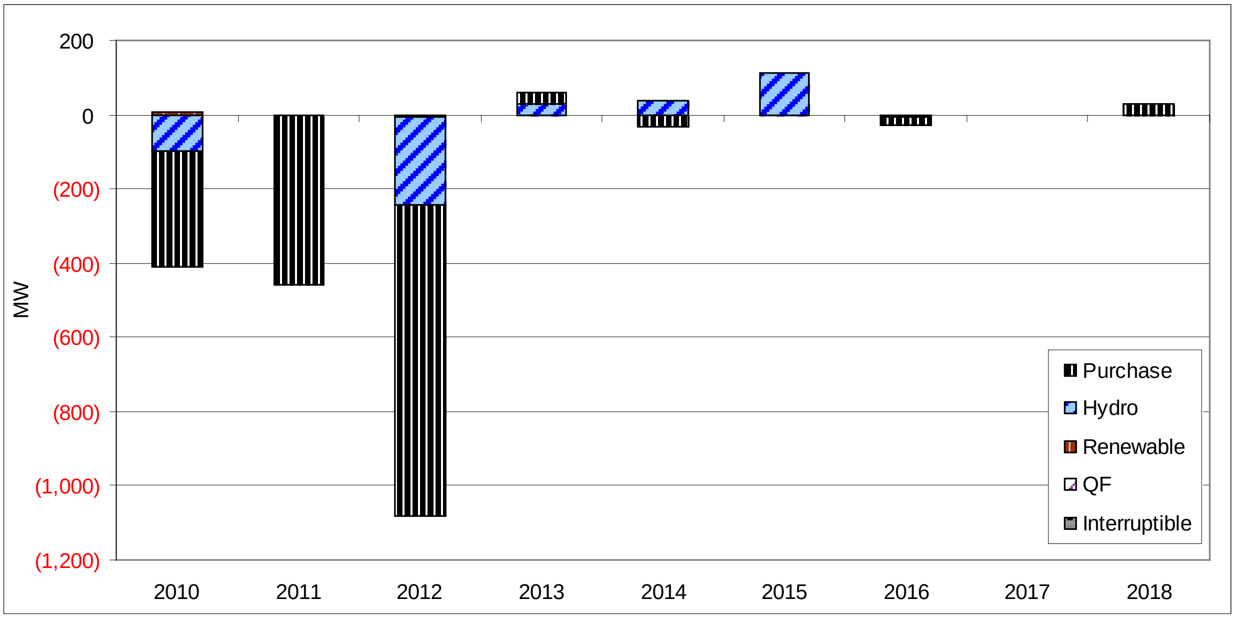


Listed below are the major contract expirations expiring between the summer 2011 and summer 2012:

BPA Peaking	575 MW
Morgan Stanley	100 MW
Morgan Stanley	100 MW
Colockum Capacity Exchange	108 MW
Rocky Reach	65 MW
Grant Displacement	63 MW

Figure 5.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

Figure 5.2 – Changes in Contract Capacity in the Load and Resource Balance



LOAD AND RESOURCE BALANCE

Capacity and Energy Balance Overview

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

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2009-2018) of the planning horizon. The peak load and the firm sales were added together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm-capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin, and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2009-2018). The average obligation (load plus sales) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

Capacity and energy balance information is reported for two scenarios: with the Lake Side II combined-cycle plant included as a firm planned resource in 2012, and Lake Side II excluded as a resource, resulting in a larger capacity deficit beginning in that year.

Load and Resource Balance Components

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

Existing Resources

The firm capacities of the existing resources are shown in Table 5.6 by resource category and summed to show the total available existing resource capacity for the east, west and for the PacifiCorp system. A description of each of the resource categories follows:

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

- **Hydro**. This category includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system peak, an approach consistent with current WECC capacity reporting practices. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. The energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation, are also accounted for. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

  The Utah commission, in its 2007 IRP acknowledgment order, directed the Company to investigate the hydro capacity accounting methodology currently under consideration for regional resource adequacy reporting purposes in the Pacific Northwest. This accounting methodology extends the one-hour sustained peaking period to the six highest load hours over three consecutive days of highest demand. This sustained peaking-period definition was adopted in 2008 by the Northwest Power and Conservation Council (NPCC) as part the capacity resource adequacy standard developed by the Pacific Northwest Resource Adequacy Forum. The hydro sustained peak capacity methodology is still being evaluated to work out certain methodology details and to determine how best to implement it on a regional basis.

The Pacific Northwest Resource Adequacy Forum hired a consultant to conduct the study, which is expected to be completed by the end of 2009.

PacifiCorp conducted a cursory analysis of hydro resource capacity using the NPCC sustained peaking-period definition. The impact of moving from a one-hour sustained peaking period to an 18-hour period was found to be negligible.

- **Demand-Side Management (DSM).** In 2009, there are projected to be about 345 megawatts of Class 1 demand-side management programs included as existing resources. These are further projected to increase to 525 MW by 2018. Both the capacity balance and the energy balance count DSM programs by program capacity. DSM resources directly curtail load and thus planning reserves are not held for them.

- **Renewable.** This category contains one geothermal project, 21 existing wind projects and two planned wind projects. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. Project-specific capacity credits for the wind resources were statistically determined. Wind energy is counted according to hourly generation data used to model the projects.

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

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

- **Interruptible.** There are three east-side load curtailment contracts in this category. These agreements with Monsanto, MagCorp and Nucor provide 237 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them.

Obligation

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

- **Load**. The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The energy balance counts the load as an average of monthly time-of-day energy (MWa).

  Due to new federal lighting standards being implemented under the Energy Policy Act of 2005, the load forecast required adjustment because lighting efficiency measures were embedded in the Class 2 DSM supply curves provided to PacifiCorp. Increasing the load forecast to account for this available energy efficiency "supply" ensures that an appropriate quantity of Class 2 DSM is selected by the capacity expansion model. Table 5.17 shows the impact of the hourly energy adjustments to the annual system coincident peak loads used in the 10-year capacity load and resource balance. (Note that this upward load adjustment applies only for capacity expansion modeling purposes. The Company's official load forecast is reported net of this DSM adjustment.)

Table 5.17 – Federal Lighting Standard Impact on System Peak loads

Year	Federal Lighting Standard Adjustment (MW)	System Coincident Peak Prior to Adjustment (MW)	Adjusted System Coincident Peak (MW)
2009	6.3	10,143	10,150
2010	10.3	10,360	10,371
2011	8.5	10,631	10,640
2012	12.2	10,978	10,991
2013	20.3	11,261	11,281
2014	50.8	11,451	11,501
2015	69.2	11,730	11,798
2016	94.1	12,032	12,127
2017	132.7	12,251	12,384
2018	151.6	12,522	12,674
2019	144.5		
2020	173.1		
2021	174.6		
2022	200.9		
2023	217.7		
2024	226.2		
2025	232.0		
2026	234.1		
2027	239.4		
2028	245.0		

- **Sales**. This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Reserves

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

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

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

- **Non-owned reserves**. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. This amounts to an annual reserve obligation of about 7 megawatts and 70 megawatts on the west and east-sides, respectively.

Position

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

Reserve Margin

The reserve margin is the ratio of existing resources to the obligation. A positive reserve margin indicates that existing resources exceeds obligation. Conversely, a negative reserve margin indicates that existing resources do not meet obligation. If existing resources equals the obligation, then the reserve margin is 0%. It should be pointed out that the reserve margin can be negative when the corresponding position is non-negative. This is because the reserve margin is measured relative to the obligation, while the position is measured relative to the obligation plus reserves.

Capacity Balance Determination

Methodology

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

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

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

Obligation *= Load + Sales*

The amount of reserves to be added to the obligation is then calculated. This is accomplished by first removing the firm purchase and load curtailment components of the existing resources from the obligation. This resulting net obligation is then multiplied by the planning reserve margin.

The non-owned reserves are then added to this result to yield the megawatts of required reserves. The formula for this calculation is the following:

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

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

Capacity Position *= Existing Resources – Obligation – Reserves*

Firm capacity transfers from PacifiCorp's western to eastern control areas are reported for the east capacity balance, while capacity transfers from the eastern to western control areas are reported for the west capacity balance. Capacity transfers represent the optimized control area interchange at the time of the system coincident peak load as determined by the System Optimizer model.[27]

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2007 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Commitment.** In the 2007 IRP, 400 megawatts of the overall 1,400-megawatt commitment are included in the load and resource balance. The remaining 1,000 megawatts were treated as part of the overall wind resource potential evaluated in portfolio modeling. In the 2008 IRP, there are 263 MW of firm planned wind projects included in the load and resource balance.

- **Coal plant turbine upgrades.** The current load and resource balance assumes 162 MW of coal plant turbine upgrades, which is down from the 202 MW assumed in the 2007 IRP Update Report.

Capacity Balance Results

Table 5.18 shows the annual capacity balances and component line items using a target planning reserve margin of 12 percent to calculate the planning reserve amount. (Capacity balance information with Lake Side II included as a planned resource in 2012 is provided in Appendix H.) Balances for the system as well as PacifiCorp's east and west control areas are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) For comparison purposes, Table 5.19 shows the system-level capacity balance assuming a 15 percent planning reserve margin.

Figures 5.3 through 5.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The decrease in resources in 2008

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[27] West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

is caused by the expected expiration of the West Valley lease agreement. The slight increase in 2009 is due to executed front office transactions and an increase in the curtailment portion of the Monsanto contract. The large decrease in 2012 is primarily due to the expiration of the BPA peaking contract in August 2011. Additionally, Figure 5.4 highlights a decrease in obligation in the west starting in 2014 attributable to the expiration of the Sacramento Municipal Utility District and City of Redding power sales contracts.

Table 5.18 – System Capacity Loads and Resources (12% Target Reserve Margin)

Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East										
Thermal	5,983	5,998	6,025	6,066	6,066	6,078	6,079	6,087	6,088	5,863
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
QF	151	151	151	151	151	151	151	151	151	151
Interruptible	237	237	237	237	237	237	237	237	237	237
Transfers	1,150	952	602	422	440	230	490	504	265	414
East Existing Resources	8,910	8,572	8,284	7,975	8,003	7,814	8,082	8,093	7,865	7,800
Load	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	7,538	7,717	7,908	8,151	8,388	8,524	8,774	9,048	9,150	9,355
Planning reserves	745	785	803	853	880	895	924	958	969	993
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	815	855	874	923	951	966	995	1,029	1,040	1,063
East Obligation + Reserves	8,352	8,572	8,781	9,074	9,339	9,490	9,769	10,077	10,190	10,418
East Position	558	1	(498)	(1,099)	(1,336)	(1,676)	(1,686)	(1,984)	(2,325)	(2,619)
East Reserve Margin	19%	12%	6%	(1%)	(4%)	(8%)	(7%)	(10%)	(13%)	(16%)
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydro	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
DSM	-	-	-	-	-	-	-	-	-	-
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
QF	120	120	120	120	120	120	120	120	120	120
Transfers	(1,152)	(953)	(603)	(422)	(442)	(228)	(489)	(504)	(263)	(415)
West Existing Resources	4,233	4,242	4,150	3,462	3,513	3,729	3,580	3,558	3,783	3,656
Load	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	3,892	3,912	3,780	3,845	3,896	3,980	3,927	3,932	4,001	4,086
Planning reserves	310	325	363	448	450	464	458	459	467	474
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	316	332	370	454	457	471	464	465	473	480
West Obligation + Reserves	4,208	4,243	4,149	4,299	4,353	4,451	4,391	4,397	4,474	4,566
West Position	25	(1)	0	(837)	(840)	(721)	(811)	(839)	(691)	(909)
West Reserve Margin	13%	12%	12%	(10%)	(10%)	(6%)	(9%)	(9%)	(5%)	(10%)
System										
Total Resources	13,143	12,815	12,433	11,437	11,515	11,543	11,662	11,651	11,648	11,456
Obligation	11,430	11,628	11,687	11,996	12,284	12,504	12,701	12,980	13,151	13,441
Reserves	1,131	1,187	1,243	1,377	1,407	1,437	1,459	1,494	1,513	1,543
Obligation + Reserves	12,561	12,815	12,931	13,373	13,692	13,940	14,160	14,474	14,664	14,984
System Position	583	(0)	(498)	(1,936)	(2,176)	(2,397)	(2,498)	(2,823)	(3,016)	(3,528)
Reserve Margin	17%	12%	8%	(4%)	(6%)	(7%)	(8%)	(10%)	(11%)	(14%)

Table 5.19 – System Capacity Loads and Resources (15% Target Reserve Margin)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
System										
Total Resources	13,143	12,815	12,433	11,437	11,515	11,543	11,662	11,651	11,648	11,456
Obligation	11,430	11,628	11,687	11,996	12,284	12,504	12,701	12,980	13,151	13,441
Reserves	1,395	1,464	1,535	1,703	1,740	1,776	1,805	1,848	1,872	1,910
Obligation + Reserves	12,824	13,092	13,222	13,698	14,024	14,280	14,505	14,828	15,023	15,351
System Position	319	(277)	(789)	(2,261)	(2,509)	(2,737)	(2,843)	(3,177)	(3,375)	(3,895)
Reserve Margin	18%	13%	8%	(4%)	(5%)	(7%)	(7%)	(9%)	(11%)	(14%)

Figure 5.3 – System Capacity Position Trend

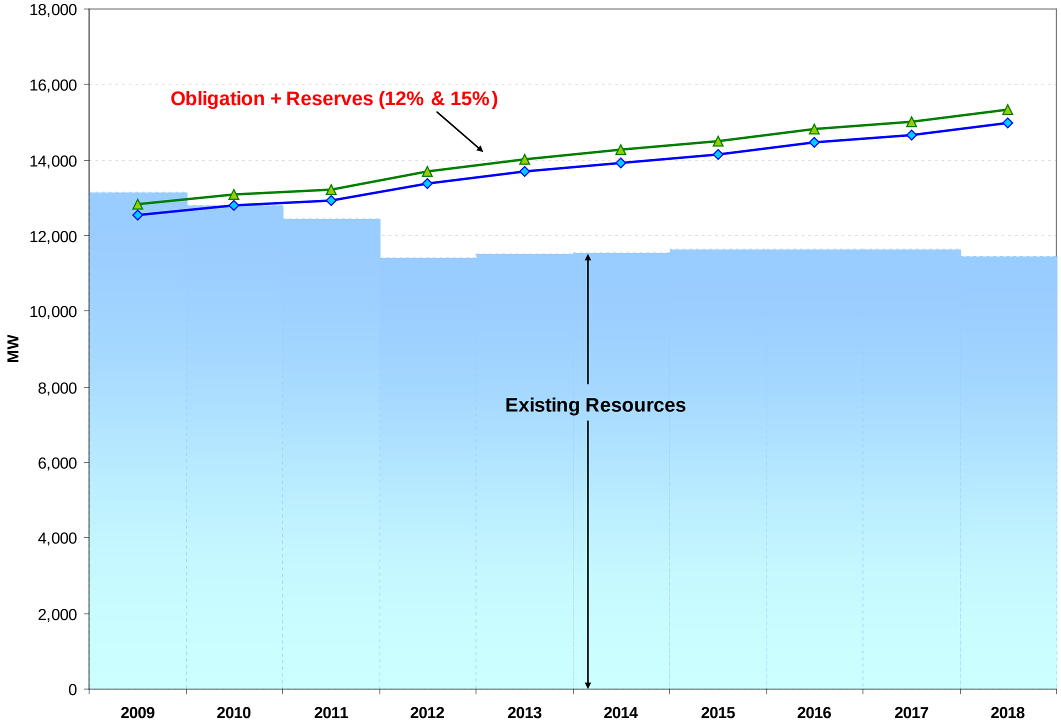


Figure 5.4 – West Capacity Position Trend

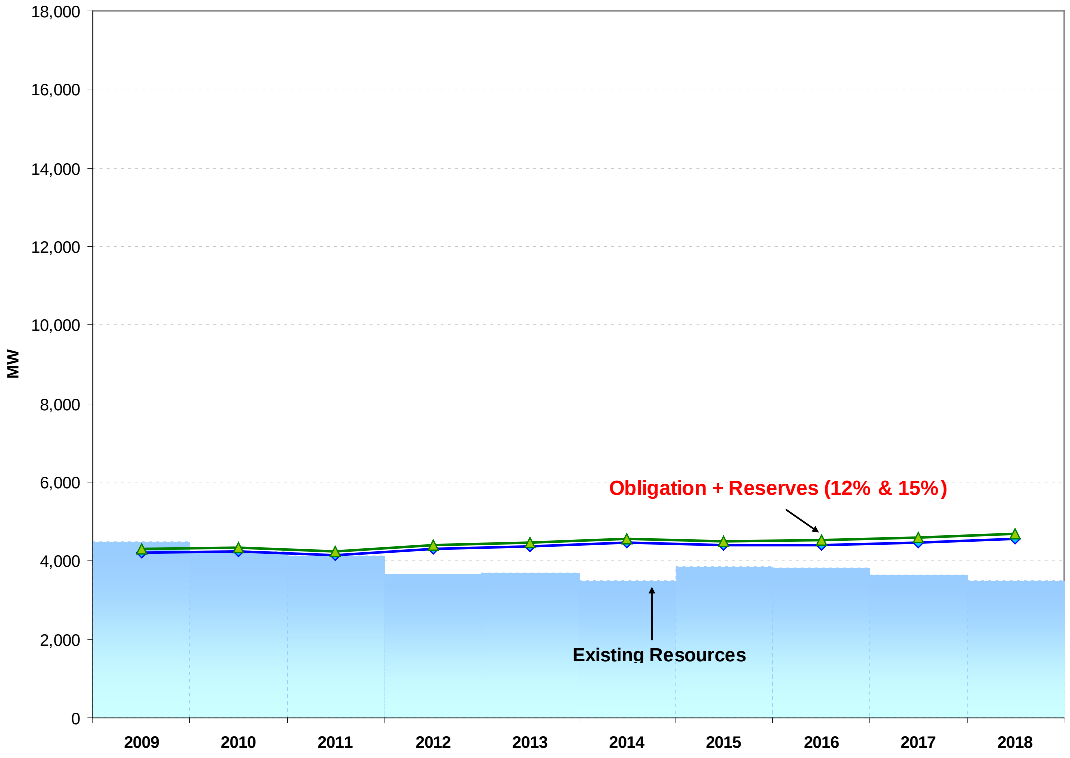
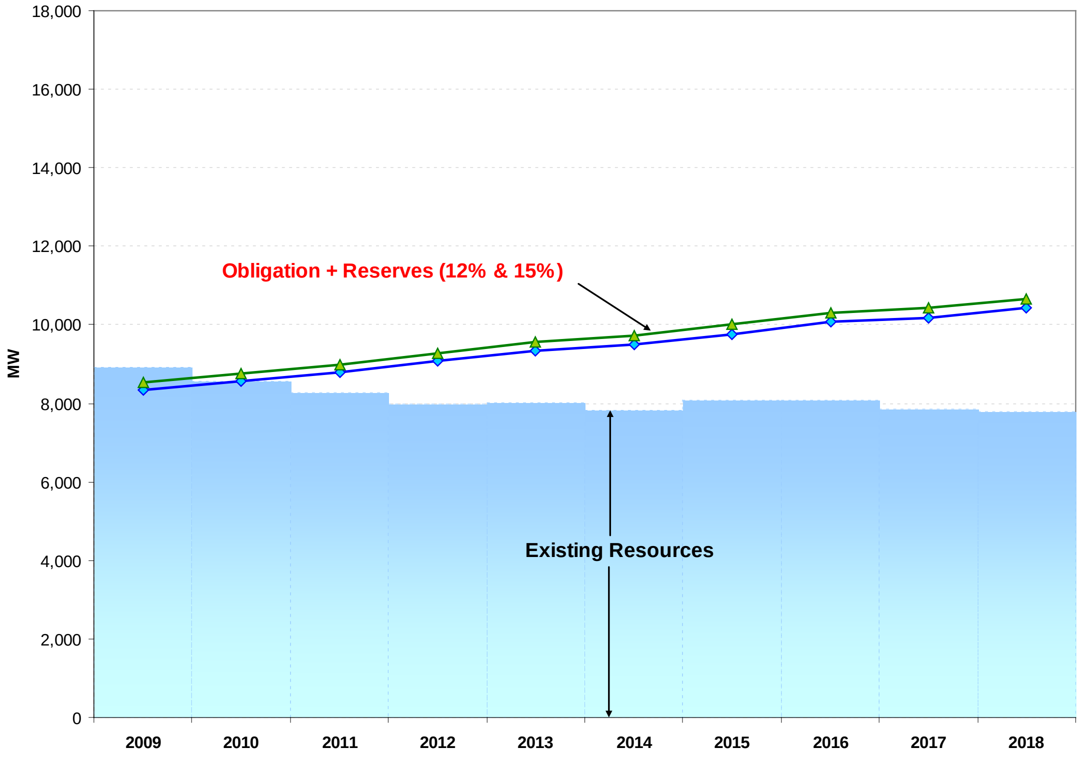


Figure 5.5 – East Capacity Position Trend



Energy Balance Determination

Methodology

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

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

The average obligation is computed using the following formula:

Obligation *= Load + Sales*

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

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

Energy Balance Results

Figures 5.6 through 5.8 show the energy balances for the system, west control area, and east control area, respectively. They indicate the energy balance on a monthly average basis across all hours, and also indicate the average annual energy position. The cross-over point, where the system starts to become energy deficient on a summer hour basis, is 2012, absent any economic considerations.

Figure 5.6 – System Average Monthly and Annual Energy Balances

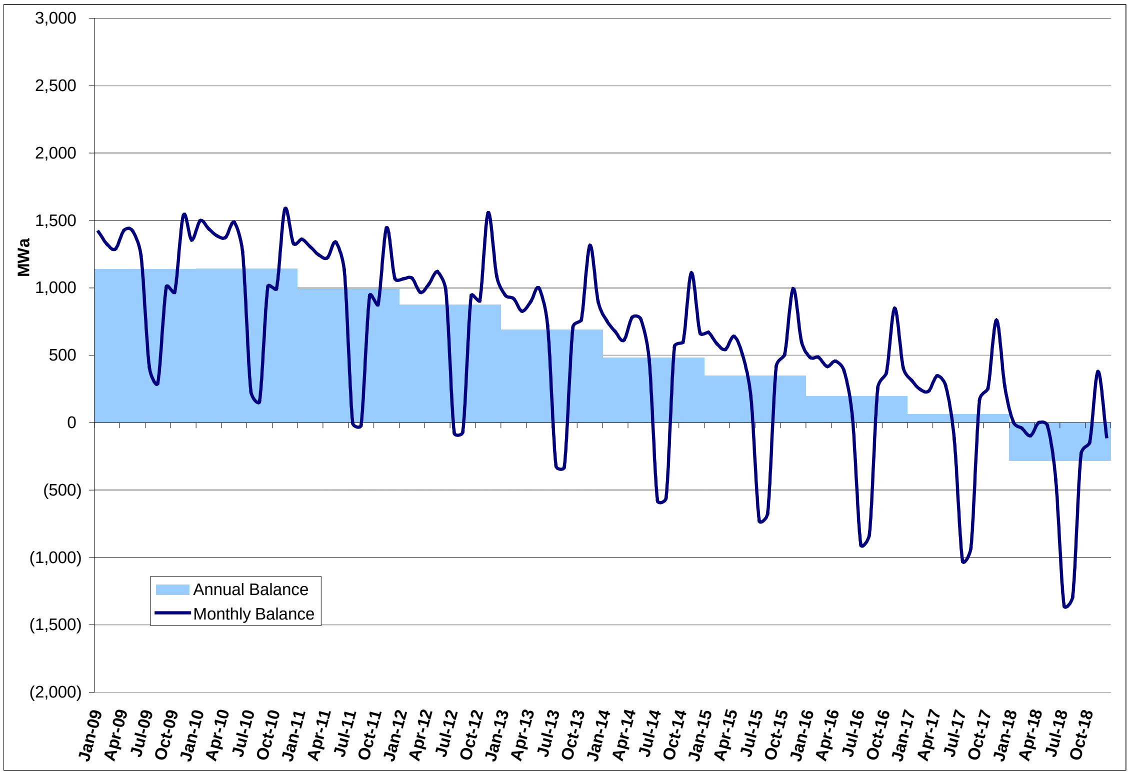


Figure 5.7 – West Average Monthly and Annual Energy Balances

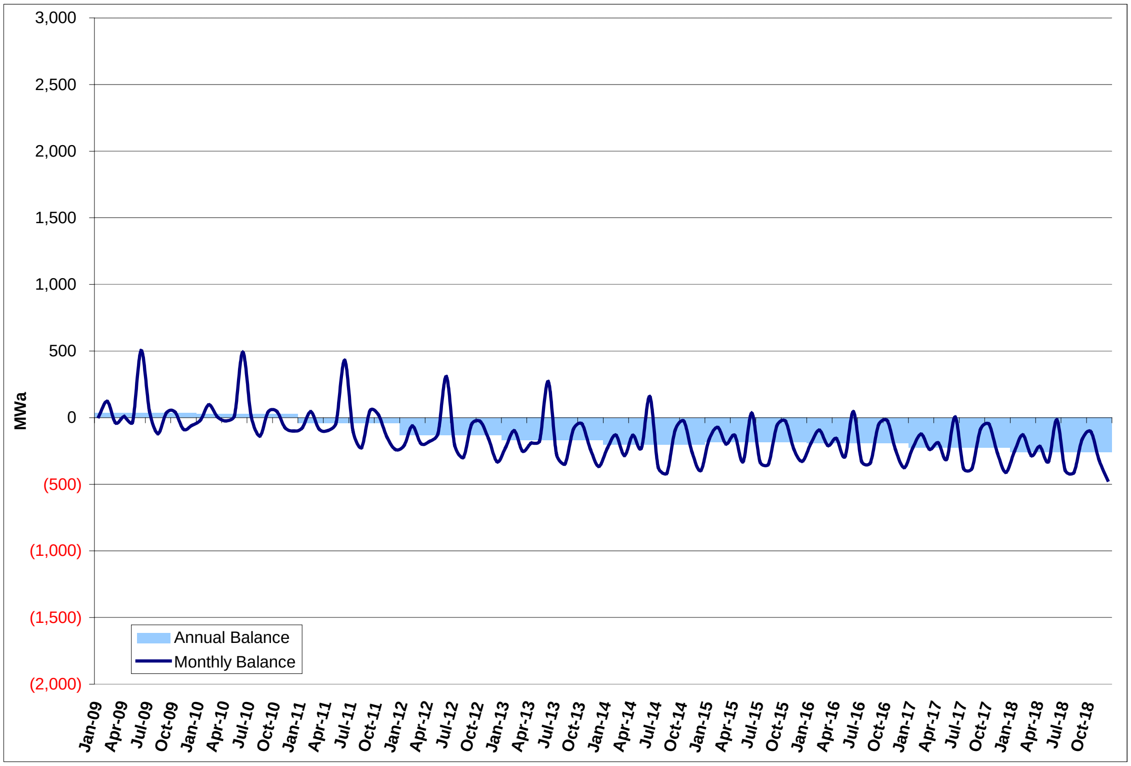
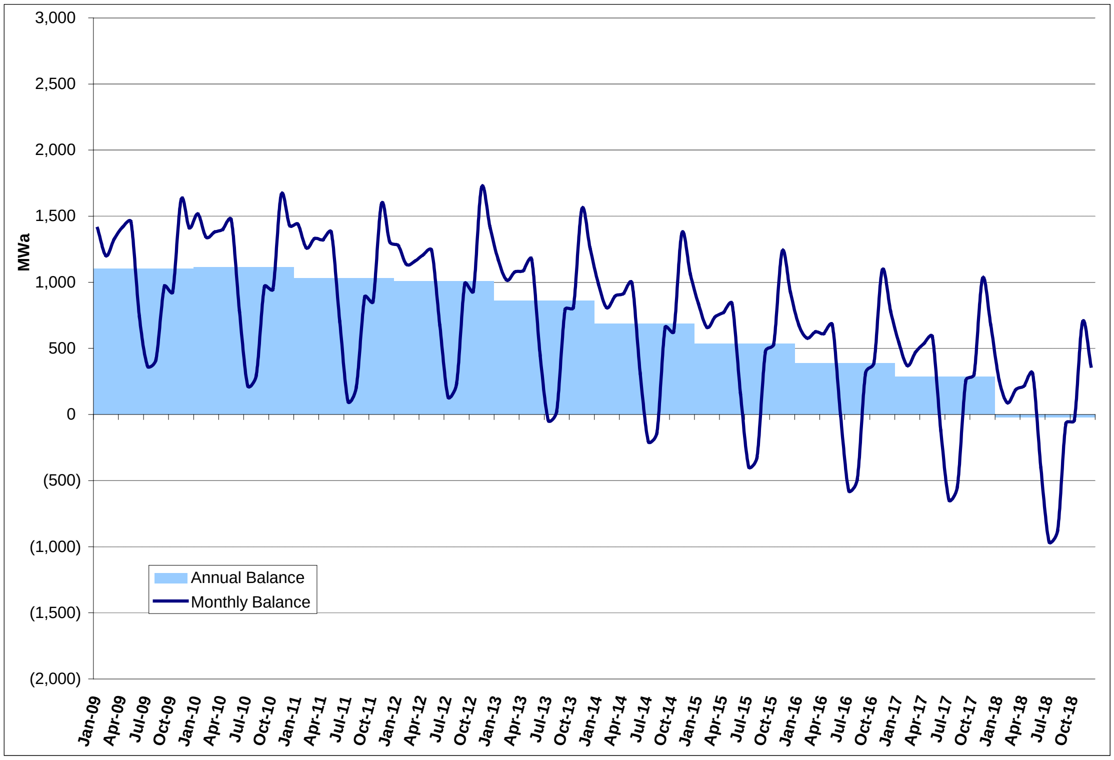


Figure 5.8 – East Average Monthly and Annual Energy Balances



Load and Resource Balance Conclusions

The Company projects a summer peak resource deficit for the PacifiCorp system beginning in 2010 to 2011, depending on the planning reserve margin assumed. The PacifiCorp deficits prior to 2012 will be met by additional renewables, demand-side programs, market purchases, and coal plant turbine upgrades. The Company will consider other options during this time frame if they are cost-effective and provide other system benefits. Then, beginning 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity deficit. The capacity balance at a 12 percent planning reserve margin indicates the start of a deficit beginning in 2011—the system is short by 498 MW. For 2012, the capacity deficit increases to 1,936 MW. By 2018, the deficit increases to 3,528 MW. The Company becomes deficit with respect to summer energy by 2012.

6. RESOURCE OPTIONS

INTRODUCTION

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

SUPPLY-SIDE RESOURCES

Resource Selection Criteria

The list of supply-side resource options has been modified in relation to previous IRP resource lists to reflect the realities evidenced through permitting, public meeting comments, and studies undertaken to better understand the details of available generation resources. For instance, coal options have been decreased with a greater emphasis on carbon capture and sequestration. Natural gas options have been expanded to include a dry-cooled combined cycle option and separate gas options were developed for Wyoming. Alternative energy resources have been given a greater emphasis. Specifically additional solar generation options and geothermal options have been included in the analysis compared to the previous IRP. Additional solar resources include utility-size (10 MWs or greater) concentrated photovoltaic as well as solar thermal with six hours of thermal storage. Energy storage systems continue to be of interest, and advanced large batteries (1 MW) have been reviewed as well as traditional pumped hydro and compressed air energy storage.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2007 IRP. This resource list was reviewed and modified to reflect public input and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. A number of information sources were used to identify parameters needed to model these resources. Supporting utility-scale resources were a number of engineering studies conducted by PacifiCorp to understand the cost of coal and gas resources in recent years. Additionally, experience with the construction of the 2x1 combined cycle plants at Currant Creek and Lake Side as well as other recent simple-cycle projects at Gadsby and West Valley provided PacifiCorp with a detailed understanding of the cost of new power generating facilities. Preparation of benchmark submittals for PacifiCorp's recent generation RFPs were also used to update actual project experience, while government studies were relied upon for characterizing future carbon capture costs.

Extensive new studies on the cost of the coal-fired options were not prepared in keeping with the reduced emphasis on these resources for new near-term generation.

The results of these estimating efforts were compared with other cost databases, such as the one supporting the IPM® market model developed by ICF International, which the Company now uses for national emissions policy impact analysis among other uses. The IPM® cost estimates were used when cost agreement was close.

The WorleyParsons Group was contracted to conduct a high-level renewable generation study specifically for solar, biomass and geothermal resources. The geothermal cost was adjusted to be consistent with estimated project costs for a third unit expansion at Blundell.

Wind costs are based on actual project experience in both the northwest and Wyoming, as well as current projections. Wind costs have been subject to increasing prices due to a lack of supply.[28] Nuclear costs are reflective of recent cost estimates associated with preliminary development activities as well as published estimates of new projects. Hydrokinetic, or wave power, has been added based on proposed projects in the Northwest. Other generation options, such as energy storage and fuel cells, were adopted from PacifiCorp's previous IRP. In some cases costs from the previous IRP were updated using cost increases for other studied resources.

New to PacifiCorp's IRP process is the addition of a variety of small-scale generation resources, consisting of distributed standby generators (DSG), combined heat and power (CHP), and onsite solar supply-side resource options. Together these small resources are referred to as distributed generation. Quantec LLC (now called the Cadmus Group, Inc.) originally provided the distributed generation costs and attributes as part of the DSM potential study conducted for PacifiCorp in 2007.[29] The DSM potential report identified the economic potential for distributed generation resources by state.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many of the proposed generation options is high. Various factors contribute to this uncertainty. Recent experience with lump-sum contracting indicates a greater risk premium is being used by bidders for the traditional turn-key contracts preferred by PacifiCorp for major projects. Shortage of skilled labor and volatile commodity prices are a large part of the increase in project costs for lump-sum contracting. For example, Figure 6.1 shows the trend in North American and world carbon steel prices for selected commodity products. This trend is expected to continue, although the economic slowdown could increase the competitiveness of future proposals as supply and demand reach a better balance.

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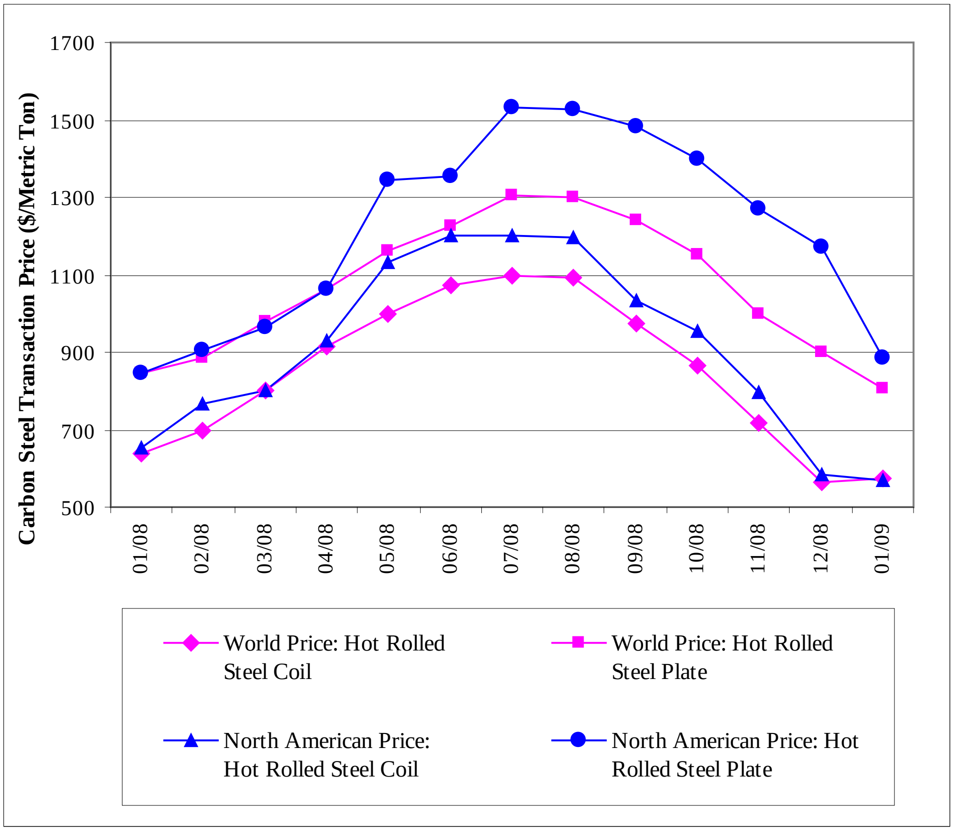
[28] For example, in April 2008, General Electric announced a wind turbine backlog worth $12 billion (CNet News.com, April 13, 2008). In 2008, Siemens Power Generation also announced a four-year backlog in turbine orders. For a review of turbine market trends, see, U.S. Department of Energy, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007 (May 2008).

[29] Quantec LLC, Assessment of Long-Term, System Wide Potential for Demand-Side and Other Supplemental Resources, July 2007.

Figure 6.1 – North American and World Carbon Steel Price Trends



Projects in high demand, such as wind turbines, have seen cost increases as much as 40 percent since the 2007 IRP was developed due to tight turbine supplies. The wind capital costs in the supply-side table were escalated at 5 percent for the years 2009 to 2011 to reflect a continuation of near-term real cost escalation as the backlog of turbine orders is reduced, then return to the nominal inflation rate of about 2 percent thereafter. Note that subsequent to completion of its 2008 IRP portfolio analysis in late 2008 and early 2009, the Company has witnessed price declines for wind turbines and other power plant equipment. These cost declines were not incorporated in portfolio cost estimates. Long-term resource pricing remains challenging to forecast.

Technologies, such as IGCC and some proposed renewable concepts like solar, have a greater uncertainty because only a few demonstration units have been built and operated. There is a potential for future relative cost decreases for these technologies. As these technologies mature and more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal and conventional natural gas-fired plants.

The supply-side resource options tables below do not consider the potential for such savings since the benefits are not expected to be realized until the next generation of new plants are built and operated for a period of time. Any such benefits are not expected to be available until after 2020, and future IRPs will be able to incorporate the benefit of such future cost reductions. A range of estimated capital costs is displayed in the supply-side resource tables. The capital cost range was created by adjusting the base-line estimates by 5 percent on the low end and 20 percent on the high end.

Introduction of many new distributed generation technologies designed to fill the needs of niche markets has helped spur reductions in capital and operating costs. In the DSM potential report, Quantec LLC provided installed cost reduction percentages reflecting these cost trends. Table 6.1 shows the percentage cost reductions by technology type. PacifiCorp applied these cost reductions to the resources included in the IRP models.

Table 6.1 – Distributed Generation Installed Cost Reduction

Technology	Installed Cost Reduction (%/year)
Reciprocating Engine	1%
Microturbine	3%
Fuel Cell	5%
Gas Turbine	1%
Anaerobic Digesters	3%
Industrial Biomass	0.5%

Resource Options and Attributes

Tables 6.2 and 6.3 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 6.4 through 6.7 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2008 dollars. The resource costs are presented for both the $8 and $45 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs.

As mentioned above, the attributes were mainly derived from PacifiCorp's recent cost studies and project experience with certain technologies adjusted to be more in line with the IPM database for ICF International. These options are included in PacifiCorp's IRP models but some duplicate gas technologies, such as the CCCT F 1x1 that were not selected in prior IRP's, were turned off to improve the System Optimizer model performance. Cost and performance values reflect analysis concluded by September 2008. Additional explanatory notes for the tables are as follows:

- Capital costs are intended to be all-inclusive, and account for Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Tables 6.2 and 6.3 reflect mid-2008 current dollars, and do not include escalation from the current year to the year of commercial operation.
- Wind sites are modeled with differing peak load carrying capability levels and capacity factors. These levels are reported for each wind site in the Wind Capacity Planning Contribution section of Appendix F.
- Certain resource names are listed as acronyms. These include:
    PC – pulverized coal
    IGCC – integrated gasification combined cycle

SCCT – simple cycle combustion turbine
CCCT – combined cycle combustion turbine
CHP – combined heat and power (cogeneration)
CCS – carbon capture and sequestration
REG – recovered energy generation

- PacifiCorp's October 2008 forward price curves were used to calculate the levelized fuel costs reported in Tables 6.4 through 6.6.
- The costs presented do not include any investment tax credits with the exception of utility solar projects that qualify for the 30% federal tax credit under the Emergency Economic Stabilization Act of 2008 signed into law in October 2008. The utility solar projects do not qualify for the federal production tax credit.
- Gas backup for solar with a heat rate of 11,750 Btu/kWh is less efficient than for a standalone CCCT.
- For the nuclear option, costs do not include fuel disposal but do include the cost of transmission.
- The capital cost columns in Tables 6.2 and 6.3 reports the low and high capital cost estimates. The average capital cost is reported in Tables 6.4 through 6.7.
- The capacity shown for retrofitting CCS on existing pulverized coal plants is a net change from current capacity (proportional to 500 MW). The heat rate is the total net plant heat rate based on a nominal 10,000 Btu/kWh without CCS.
- The wind resources entered in the table are representative resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources would be performed as part of the acquisition process. Also, the listed capacity factors are not intended to characterize wind quality for a particular region.
- Heat rates are not adjusted for degradation over time. PacifiCorp assumes that efficiency improvements will offset degradation impacts.

Table 6.2 – East Side Supply-Side Resource Options

	Location / Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation Location	Earliest In-Service Date Mid-Year	Average Capacity (MW)	Design Plant Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Low Estimate Capital Cost ($/kW)	High Estimate Capital Cost ($/kW)	Var. O&M ($/MWh)	Fixed O&M ($/kw-yr)	SO2 lbs/MMBTU	NOx lbs/MMBTU	Hg lbs/Tbtu	CO2 lbs/MMBTU
East Side Options (4500')															
Coal															
Utah PC without Carbon Capture & Sequestration	Utah	2020	600	40	9,106	5%	4%	2,788	3,521	$ 0.96	$ 38.80	0.100	0.070	0.40	205.35
Utah PC with Carbon Capture & Sequestration	Utah	2025	526	40	13,087	5%	5%	5,040	6,367	$ 6.71	$ 66.07	0.050	0.020	0.20	20.54
Utah IGCC with Carbon Capture & Sequestration	Utah	2025	466	40	10,823	7%	8%	4,880	6,164	$ 11.28	$ 53.24	0.050	0.011	0.04	20.54
Wyoming PC without Carbon Capture & Sequestration	Wyoming	2020	790	40	9,214	5%	4%	3,156	3,987	$ 1.27	$ 36.00	0.100	0.070	0.60	205.35
Wyoming PC with Carbon Capture & Sequestration	Wyoming	2025	692	40	13,242	5%	5%	5,707	7,209	$ 7.26	$ 61.37	0.050	0.020	0.30	20.54
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	2025	456	40	11,047	7%	8%	5,525	6,979	$ 13.52	$ 58.00	0.050	0.011	0.06	20.54
Existing PC with Carbon Capture & Sequestration (500 MW)	UT / WY	2025	(139)	20	14,372	5%	5%	1,253	1,583	$ 6.71	$ 66.07	0.050	0.011	0.30	20.54
Natural Gas															
Utility Cogeneration	Utah	2011	10	25	4,974	10%	8%	4,822	6,091	$ 23.29	$ 1.86	-	-	0.26	118.00
Fuel Cell - Large	Utah	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.40	0.001	-	0.26	118.00
SCCT Aero	Utah	2012	118	30	9,773	4%	3%	1,070	1,351	$ 5.63	$ 9.95	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Utah	2012	174	30	9,402	4%	3%	999	1,262	$ 2.71	$ 4.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Utah	2012	261	30	9,402	4%	3%	999	1,262	$ 2.71	$ 4.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Wyoming	2012	241	30	9,402	4%	3%	1,083	1,368	$ 2.94	$ 4.39	0.001	0.011	0.26	118.00
Internal Combustion Engines	Utah	2009	153	30	8,500	5%	1%	1,258	1,589	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Utah	2012	302	35	11,659	4%	3%	710	897	$ 4.47	$ 3.74	0.001	0.050	0.26	118.00
SCCT Frame (2 Frame "F")	Wyoming	2012	275	35	11,659	4%	3%	770	972	$ 4.85	$ 4.05	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Utah	2013	222	40	7,302	4%	3%	1,298	1,640	$ 2.94	$ 12.79	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Utah	2013	50	40	8,869	4%	3%	530	669	$ 0.39	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Utah	2013	506	40	7,098	4%	3%	1,182	1,493	$ 2.94	$ 7.77	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Utah	2013	64	40	8,557	4%	3%	596	753	$ 0.39	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Dry "F" 2x1)	Utah	2017	438	40	7,368	4%	3%	1,212	1,530	$ 3.35	$ 9.69	0.001	0.011	0.26	118.00
CCCT Duct Firing (Dry "F" 2x1)	Utah	2017	98	40	8,950	4%	3%	611	772	$ 0.11	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Utah	2013	333	40	6,884	4%	3%	1,227	1,550	$ 4.56	$ 6.75	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Utah	2013	72	40	9,021	4%	3%	520	656	$ 0.36	$ 1.63	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Utah	2018	400	40	6,760	4%	3%	1,355	1,712	$ 4.56	$ 6.75	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Utah	2018	75	40	9,021	4%	3%	665	840	$ 0.36	$ 1.63	0.001	0.011	0.26	118.00
Other - Renewables															
East (Wyoming) Wind (35% CF)	Wyoming	2010	100	25	n/a	n/a	n/a	2,215	2,954	-	$ 31.43	-	-	-	-
East Side Geothermal (Blundell)	Utah	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
East Side Geothermal (Green Field)	Utah	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
Battery Storage	Utah	2014	5	30	12,000	2%	5%	1,980	2,501	$ 10.00	$ 1.00	0.100	0.400	3.00	205.35
Pumped Storage	Nevada	2018	350	50	13,000	5%	5%	1,684	2,127	$ 4.30	$ 4.30	0.100	0.400	3.00	205.35
Compressed Air Energy Storage (CAES)	Wyoming	2015	350	30	11,980	4%	3%	1,483	1,873	$ 5.50	$ 3.80	0.001	0.011	0.26	118.00
Recovered Energy Generation (CHP)	UT / WY	2011	12	30	-	8%	8%	5,500	5,500	-	$ 91.92	-	-	-	-
Nuclear	Utah	2025	1,600	40	10,710	7%	8%	5,188	6,553	$ 1.63	$ 146.70	-	-	-	-
Solar Concentrating (PV) - 30% CF	Utah	2015	10	20	n/a	n/a	n/a	6,194	7,824	-	$ 180.00	-	-	-	-
Solar Concentrating (natural gas backup) - 25% solar	Utah	2015	250	20	n/a	n/a	n/a	3,943	4,980	-	$ 195.60	-	-	-	-
Solar Concentrating (thermal storage) - 30% solar	Utah	2012	250	30	n/a	n/a	n/a	4,418	5,580	-	$ 139.50	-	-	-	-

Table 6.3 – West Side Supply-Side Resource Options

	Location / Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation Location	Earliest In-Service Date Mid-Year	Average Capacity (MW)	Design Plant Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Low Estimate Capital Cost ($/kW)	High Estimate Capital Cost ($/kW)	Var. O&M ($/MWh)	Fixed O&M ($/kw-yr)	SO2 lbs/MMBTU	NOx lbs/MMBTU	Hg lbs/Tbtu	CO2 lbs/MMBTU
West Side Options (1500')															
Natural Gas															
Fuel Cell - Large	Northwest	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.40	0.001	-	0.26	118.00
SCCT Aero	Northwest	2012	130	30	9,773	4%	3%	972	1,228	$ 5.12	$ 9.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Northwest	2012	287	30	9,402	4%	3%	908	1,147	$ 2.46	$ 3.68	0.001	0.011	0.26	118.00
Internal Combustion Engines	Northwest	2012	168	30	8,500	5%	1%	1,143	1,444	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Northwest	2012	338	35	11,659	4%	3%	645	815	$ 4.07	$ 3.40	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Northwest	2013	244	40	7,302	4%	3%	1,180	1,491	$ 2.67	$ 11.62	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2013	55	40	8,869	4%	3%	482	608	$ 0.36	$ 1.45	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Northwest	2013	557	40	7,098	4%	3%	1,074	1,357	$ 2.67	$ 7.07	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2013	70	40	8,557	4%	3%	542	685	$ 0.36	$ 1.45	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Northwest	2013	367	40	6,884	4%	3%	1,116	1,409	$ 4.14	$ 6.13	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2013	80	40	9,021	4%	3%	472	597	$ 0.33	$ 1.48	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Northwest	2018	440	40	6,760	4%	3%	1,232	1,556	$ 4.14	$ 6.13	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Northwest	2018	83	40	9,021	4%	3%	605	764	$ 0.33	$ 1.48	0.001	0.011	0.26	118.00
Other - Renewables															
West Wind	Northwest	2010	50	25	n/a	n/a	n/a	2,350	3,134	-	$ 31.43	-	-	-	-
Biomass	Northwest	2015	50	30	10,979	5%	4%	3,179	4,016	$ 0.96	$ 38.80	0.100	0.350	0.40	205.39
West Side Geothermal (Green Field)	Northwest	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
Compressed Air Energy Storage (CAES)	Northwest	2015	385	30	11,980	4%	3%	1,483	1,873	$ 5.00	$ 3.45	0.001	0.011	0.26	118.00
Hydrokinetic (Wave) - 21% CF	Northwest	2015	100	20	n/a	n/a	n/a	5,700	7,200	-	$ 180.00	-	-	-	-
West Side Options (Sea Level)															
Natural Gas															
Fuel Cell - Large	Northwest	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.40	0.001	-	0.26	118.00
SCCT Aero	Northwest	2012	136	30	9,773	2%	3%	924	1,167	$ 4.87	$ 8.59	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Northwest	2012	302	30	9,402	4%	3%	863	1,090	$ 2.35	$ 3.49	0.001	0.011	0.26	118.00
Internal Combustion Engines	Northwest	2012	177	30	8,500	4%	1%	1,086	1,372	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Northwest	2012	356	35	11,659	5%	3%	613	774	$ 3.87	$ 3.23	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Northwest	2013	257	40	7,302	4%	3%	1,121	1,416	$ 2.55	$ 11.07	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2013	58	40	8,869	4%	3%	458	578	$ 0.34	$ 1.38	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Northwest	2013	586	40	7,098	4%	3%	1,020	1,289	$ 2.55	$ 6.73	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2013	74	40	8,557	4%	3%	515	650	$ 0.34	$ 1.38	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Northwest	2013	386	40	6,884	4%	3%	1,060	1,339	$ 3.94	$ 5.84	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2010	84	40	9,021	4%	3%	449	567	$ 0.31	$ 1.41	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Northwest	2018	463	40	6,760	4%	3%	1,170	1,479	$ 3.94	$ 5.84	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Northwest	2018	87	40	9,021	4%	3%	574	725	$ 0.31	$ 1.41	0.001	0.011	0.26	119.00

Table 6.4 – Total Resource Cost for East Side Supply-Side Resource Options, $8 CO_2 Tax

	Capital Cost $/kW			**Fixed Cost**				**Convert to Mills**				**Variable Costs** mills/kWh				**Total Resource Cost**
				Fixed O&M $/kW-Yr						Levelized Fuel						
Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	**(Mills/kWh)**
East Side Options (4500')																
Coal																
Utah PC without Carbon Capture & Sequestration	2,934	8.40%	$ 246.57	$ 38.80	$ 6.00	$ 44.80	$ 291.37	91%	36.39	216.23	19.69	$ 0.96	-	-	5.10	62.14
Utah PC with Carbon Capture & Sequestration	5,306	8.25%	$ 437.60	$ 66.07	$ 6.00	$ 72.07	$ 509.68	90%	64.65	216.23	28.30	$ 6.71	-	-	0.78	100.43
Utah IGCC with Carbon Capture & Sequestration	5,136	8.01%	$ 411.32	$ 53.24	$ 6.00	$ 59.24	$ 470.56	85%	63.20	216.23	23.40	$ 11.28	-	-	0.64	98.52
Wyoming PC without Carbon Capture & Sequestration	3,322	8.40%	$ 279.19	$ 36.00	$ 6.00	$ 42.00	$ 321.19	91%	40.12	238.45	21.97	$ 1.27	-	-	5.16	68.52
Wyoming PC with Carbon Capture & Sequestration	6,007	8.25%	$ 495.50	$ 61.37	$ 6.00	$ 67.37	$ 562.86	90%	71.39	238.45	31.58	$ 7.26	-	-	0.79	111.02
Wyoming IGCC with Carbon Capture & Sequestration	5,816	8.01%	$ 465.74	$ 58.00	$ 6.00	$ 64.00	$ 529.74	85%	71.14	238.45	26.34	$ 13.52	-	-	0.66	111.66
Existing PC with Carbon Capture & Sequestration (500 MW)	1,319	10.71%	$ 141.23	$ 66.07	$ 6.00	$ 72.07	$ 213.30	90%	27.05	238.45	34.27	$ 6.71	-	-	0.86	68.89
Natural Gas																
Utility Cogeneration	5,076	10.12%	$ 513.46	$ 1.86	$ 0.50	$ 2.36	$ 515.82	82%	71.81	699.22	34.78	$ 23.29	4.17	-	1.58	135.63
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	699.22	50.78	$ 0.03	6.09	-	2.30	79.06
SCCT Aero	1,126	9.08%	$ 102.21	$ 9.95	$ 0.50	$ 10.45	$ 112.66	21%	61.24	699.22	68.34	$ 5.63	8.20	-	3.10	146.51
Intercooled Aero SCCT (Utah, 174MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	699.22	65.74	$ 2.71	7.89	-	2.98	133.68
Intercooled Aero SCCT (Utah, 261MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	699.22	65.74	$ 2.71	7.89	-	2.98	133.68
Intercooled Aero SCCT (Wyoming, 241MW)	1,140	9.08%	$ 103.50	$ 4.39	$ 0.50	$ 4.89	$ 108.38	21%	58.92	699.22	65.74	$ 2.94	6.83	-	2.98	137.41
Internal Combustion Engines	1,324	9.08%	$ 120.18	$ 12.80	$ 0.50	$ 13.30	$ 133.48	94%	16.21	699.22	59.43	$ 5.20	7.13	-	2.70	90.67
SCCT Frame (2 Frame "F")	747	8.62%	$ 64.39	$ 3.74	$ 0.50	$ 4.24	$ 68.62	21%	37.30	699.22	81.53	$ 4.47	9.78	-	3.70	136.78
SCCT Frame (2 Frame "F")	810	8.62%	$ 69.82	$ 4.05	$ 0.50	$ 4.55	$ 74.37	21%	40.43	699.22	81.53	$ 4.85	8.47	-	3.70	138.97
CCCT (Wet "F" 1x1)	1,366	8.59%	$ 117.32	$ 12.79	$ 0.50	$ 13.29	$ 130.61	56%	26.62	699.22	51.06	$ 2.94	6.13	-	2.32	89.07
CCCT Duct Firing (Wet "F" 1x1)	558	8.59%	$ 47.88	$ 1.60	$ 0.50	$ 2.10	$ 49.98	16%	35.66	699.22	62.01	$ 0.39	7.44	-	2.81	108.32
CCCT (Wet "F" 2x1)	1,244	8.59%	$ 106.79	$ 7.77	$ 0.50	$ 8.27	$ 115.06	56%	23.46	699.22	49.63	$ 2.94	5.96	-	2.25	84.24
CCCT Duct Firing (Wet "F" 2x1)	628	8.59%	$ 53.88	$ 1.60	$ 0.50	$ 2.10	$ 55.98	16%	39.94	699.22	59.84	$ 0.39	7.18	-	2.71	110.06
CCCT (Dry "F" 2x1)	1,275	8.59%	$ 109.50	$ 9.69	$ 0.50	$ 10.19	$ 119.70	56%	24.40	699.22	51.52	$ 3.35	6.18	-	2.34	87.79
CCCT Duct Firing (Dry "F" 2x1)	644	8.59%	$ 55.25	$ 1.60	$ 0.50	$ 2.10	$ 57.35	16%	40.91	699.22	62.58	$ 0.11	7.51	-	2.84	113.95
CCCT (Wet "G" 1x1)	1,292	8.59%	$ 110.93	$ 6.75	$ 0.50	$ 7.25	$ 118.18	56%	24.09	699.22	48.14	$ 4.56	5.78	-	2.18	84.74
CCCT Duct Firing (Wet "G" 1x1)	547	8.59%	$ 46.96	$ 1.63	$ 0.50	$ 2.13	$ 49.09	16%	35.03	699.22	63.08	$ 0.36	7.57	-	2.86	108.89
CCCT Advanced (Wet)	1,427	8.59%	$ 122.49	$ 6.75	$ 0.50	$ 7.25	$ 129.74	56%	26.45	699.22	47.27	$ 4.56	5.67	-	2.14	86.08
CCCT Advanced Duct Firing (Wet)	700	8.59%	$ 60.10	$ 1.63	$ 0.50	$ 2.13	$ 62.24	16%	44.40	699.22	63.08	$ 0.36	7.57	-	2.86	118.27
Other - Renewables																
East (Wyoming) Wind (35% CF)	2,566	8.72%	$ 223.58	$ 31.43	$ 0.50	$ 31.93	$ 255.51	35%	83.34	-	-	-	11.75	(20.70)	-	74.38
East Side Geothermal (Blundell)	6,087	7.42%	$ 451.64	$ 110.85	$ 0.50	$ 111.35	$ 562.99	90%	71.41	-	-	$ 5.94		(20.70)	-	56.64
East Side Geothermal (Green Field)	7,608	7.42%	$ 564.55	$ 221.70	$ 0.50	$ 222.20	$ 786.74	90%	99.79	-	-	$ 11.88		(20.70)	-	90.97
Battery Storage	2,084	8.29%	$ 172.77	$ 1.00	$ 0.50	$ 1.50	$ 174.27	21%	94.73	699.22	83.91	$ 10.00	10.07	-	6.73	205.43
Pumped Storage	1,773	8.19%	$ 145.14	$ 4.30	$ 1.35	$ 5.65	$ 150.79	20%	86.06	699.22	90.90	$ 4.30	10.91	-	7.29	199.46
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.80	$ 1.35	$ 5.15	$ 134.56	47%	32.89	699.22	83.77	$ 5.50	8.70	-	3.80	134.66
Recovered Energy Generation (CHP)	5,500	9.39%	$ 516.67	$ 91.92	-	$ 91.92	$ 608.59	84%	82.71	-	-	-	-	-	-	82.71
Nuclear	5,461	8.30%	$ 453.26	$ 146.70	$ 6.00	$ 152.70	$ 605.95	85%	81.38	113.98	12.21	$ 1.63	-	-	-	95.22
Solar Concentrating (PV) - 30% CF	6,520	6.48%	$ 422.43	$ 180.00	$ 6.00	$ 186.00	$ 608.43	30%	231.52	-	-	-	-	(1.59)	-	229.93
Solar Concentrating (natural gas backup) - 25% solar	4,150	6.48%	$ 268.88	$ 195.60	$ 6.00	$ 201.60	$ 470.48	33%	162.75	699.22	18.96	-	2.28	(1.59)	0.86	183.26
Solar Concentrating (thermal storage) - 30% solar	4,650	5.46%	$ 253.80	$ 139.50	$ 6.00	$ 145.50	$ 399.30	30%	151.94	-	-	-	-	(1.59)	-	150.35

Table 6.5 – Total Resource Cost for West Side Supply-Side Resource Options, \$8 CO_2 Tax

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs				Total
			Annual	Fixed O&M $/kW-Yr								mills/kWh				Resource
	Total	Payment	Payment				Total Fixed	Capacity Factor	Total Fixed	Levelized Fuel						Cost
Description	Capital Cost	Factor	($/kW-Yr)	O&M	Other	Total	($/kW-Yr)		Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	**(Mills/kWh)**
West Side Options (1500')																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	814.00	59.11	$ 0.03	5.33	-	2.30	86.63
SCCT Aero	1,024	9.08%	$ 92.92	$ 9.04	$ 0.50	$ 9.54	$ 102.46	21%	55.70	814.00	79.55	$ 5.12	7.17	-	3.10	150.64
Intercooled Aero SCCT	956	9.08%	$ 86.77	$ 3.68	$ 0.50	$ 4.18	$ 90.95	21%	49.44	814.00	76.53	$ 2.46	6.90	-	2.98	138.32
Internal Combustion Engines	1,204	9.08%	$ 109.25	$ 12.80	$ 0.50	$ 13.30	$ 122.55	94%	14.88	814.00	69.19	$ 5.20	6.24	-	2.70	98.20
SCCT Frame (2 Frame "F")	679	8.62%	$ 58.53	$ 3.40	$ 0.50	$ 3.90	$ 62.43	21%	33.94	814.00	94.91	$ 4.07	8.56	-	3.70	145.16
CCCT (Wet "F" 1x1)	1,242	8.59%	$ 106.66	$ 11.62	$ 0.50	$ 12.12	$ 118.78	56%	24.21	814.00	59.44	$ 2.67	5.36	-	2.32	94.00
CCCT Duct Firing (Wet "F" 1x1)	507	8.59%	$ 43.53	$ 1.45	$ 0.50	$ 1.95	$ 45.48	16%	32.45	814.00	72.19	$ 0.36	6.51	-	2.81	114.32
CCCT (Wet "F" 2x1)	1,131	8.59%	$ 97.08	$ 7.07	$ 0.50	$ 7.57	$ 104.65	56%	21.33	814.00	57.78	$ 2.67	5.21	-	2.25	89.25
CCCT Duct Firing (Wet "F" 2x1)	570	8.59%	$ 48.98	$ 1.45	$ 0.50	$ 1.95	$ 50.93	16%	36.34	814.00	69.66	$ 0.36	6.28	-	2.71	115.35
CCCT (Wet "G" 1x1)	1,175	8.59%	$ 100.85	$ 6.13	$ 0.50	$ 6.63	$ 107.48	56%	21.91	814.00	56.04	$ 4.14	5.05	-	2.18	89.32
CCCT Duct Firing (Wet "G" 1x1)	497	8.59%	$ 42.69	$ 1.48	$ 0.50	$ 1.98	$ 44.68	16%	31.88	814.00	73.43	$ 0.33	6.62	-	2.86	115.12
CCCT Advanced (Wet)	1,297	8.59%	$ 111.36	$ 6.13	$ 0.50	$ 6.63	$ 117.99	56%	24.05	814.00	55.02	$ 4.14	4.96	-	2.14	90.32
CCCT Advanced Duct Firing (Wet)	636	8.59%	$ 54.64	$ 1.48	$ 0.50	$ 1.98	$ 56.62	16%	40.40	814.00	73.43	$ 0.33	6.62	-	2.86	123.64
Other - Renewables																
West Wind	2,612	8.72%	$ 227.59	$ 31.43	$ 27.74	$ 59.17	$ 286.76	29%	112.88	-	-	-	11.75	(20.70)	-	103.93
Biomass	3,347	8.10%	$ 271.22	$ 38.80	$ 0.50	$ 39.30	$ 310.52	91%	38.78	590.00	64.78	$ 0.96	-	(20.70)	6.15	89.97
West Side Geothermal (Green Field)	7,609	7.42%	$ 564.62	$ 221.70	$ 0.50	$ 222.20	$ 786.82	90%	99.80	-	-	$ 11.88	-	(20.70)	-	90.98
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.45	$ 1.35	$ 4.80	$ 134.21	47%	32.81	814.00	97.52	$ 5.00	8.79	-	3.80	147.91
Hydrokinetic (Wave) - 21% CF	6,000	9.69%	$ 581.58	$ 180.00	$ 6.00	$ 186.00	$ 767.58	21%	417.25	-	-	-	-	-	-	417.25
West Side Options (Sea Level)																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	814.00	59.11	$ 0.03	5.33	-	2.30	86.63
SCCT Aero	972	9.08%	$ 88.27	$ 8.59	$ 0.50	$ 9.09	$ 97.36	21%	52.93	814.00	79.55	$ 4.87	7.17	-	3.10	147.63
Intercooled Aero SCCT	908	9.08%	$ 82.43	$ 3.49	$ 0.50	$ 3.99	$ 86.43	21%	46.98	814.00	76.53	$ 2.35	6.90	-	2.98	135.74
Internal Combustion Engines	1,143	9.08%	$ 103.79	$ 12.80	$ 0.50	$ 13.30	$ 117.09	94%	14.22	814.00	69.19	$ 5.20	6.24	-	2.70	97.54
SCCT Frame (2 Frame "F")	645	8.62%	$ 55.61	$ 3.23	$ 0.50	$ 3.73	$ 59.34	21%	32.26	814.00	94.91	$ 3.87	8.56	-	3.70	143.29
CCCT (Wet "F" 1x1)	1,180	8.59%	$ 101.32	$ 11.07	$ 0.50	$ 11.57	$ 112.89	56%	23.01	814.00	59.44	$ 2.55	5.36	-	2.32	92.67
CCCT Duct Firing (Wet "F" 1x1)	482	8.59%	$ 41.35	$ 1.38	$ 0.50	$ 1.88	$ 43.23	16%	30.85	814.00	72.19	$ 0.34	6.51	-	2.81	112.70
CCCT (Wet "F" 2x1)	1,074	8.59%	$ 92.23	$ 6.73	$ 0.50	$ 7.23	$ 99.46	56%	20.27	814.00	57.78	$ 2.55	5.21	-	2.25	88.06
CCCT Duct Firing (Wet "F" 2x1)	542	8.59%	$ 46.53	$ 1.38	$ 0.50	$ 1.88	$ 48.42	16%	34.54	814.00	69.66	$ 0.34	6.28	-	2.71	113.53
CCCT (Wet "G" 1x1)	1,116	8.59%	$ 95.81	$ 5.84	$ 0.50	$ 6.34	$ 102.15	56%	20.82	814.00	56.04	$ 3.94	5.05	-	2.18	88.04
CCCT Duct Firing (Wet "G" 1x1)	472	8.59%	$ 40.56	$ 1.41	$ 0.50	$ 1.91	$ 42.47	16%	30.30	814.00	73.43	$ 0.31	6.62	-	2.86	113.53
CCCT Advanced (Wet)	1,232	8.59%	$ 105.79	$ 5.84	$ 0.50	$ 6.34	$ 112.13	56%	22.86	814.00	55.02	$ 3.94	4.96	-	2.14	88.93
CCCT Advanced Duct Firing (Wet)	605	8.59%	$ 51.91	$ 1.41	$ 0.50	$ 1.91	$ 53.82	16%	38.40	814.00	73.43	$ 0.31	6.62	-	2.89	121.65

Table 6.6 – Total Resource Cost for East Side Supply-Side Resource Options, $45 CO_2 Tax

	Capital Cost $/kW			**Fixed Cost**				**Convert to Mills**				**Variable Costs** mills/kWh				**Total Resource Cost**
				Fixed O&M $/kW-Yr						Levelized Fuel						
Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	**(Mills/kWh)**
East Side Options (4500')																
Coal																
Utah PC without Carbon Capture & Sequestration	2,934	8.40%	$ 246.57	$ 38.80	$ 6.00	$ 44.80	$ 291.37	91%	36.39	216.23	19.69	$ 0.96	-	-	28.32	85.36
Utah PC with Carbon Capture & Sequestration	5,306	8.25%	$ 437.60	$ 66.07	$ 6.00	$ 72.07	$ 509.68	90%	64.65	216.23	28.30	$ 6.71	-	-	4.11	103.76
Utah IGCC with Carbon Capture & Sequestration	5,136	8.01%	$ 411.32	$ 53.24	$ 6.00	$ 59.24	$ 470.56	85%	63.20	216.23	23.40	$ 11.28	-	-	3.40	101.28
Wyoming PC without Carbon Capture & Sequestration	3,322	8.40%	$ 279.19	$ 36.00	$ 6.00	$ 42.00	$ 321.19	91%	40.12	238.45	21.97	$ 1.27	-	-	28.66	92.02
Wyoming PC with Carbon Capture & Sequestration	6,007	8.25%	$ 495.50	$ 61.37	$ 6.00	$ 67.37	$ 562.86	90%	71.39	238.45	31.58	$ 7.26	-	-	4.16	114.39
Wyoming IGCC with Carbon Capture & Sequestration	5,816	8.01%	$ 465.74	$ 58.00	$ 6.00	$ 64.00	$ 529.74	85%	71.14	238.45	26.34	$ 13.52	-	-	3.47	114.47
Existing PC with Carbon Capture & Sequestration (500 MW)	1,319	10.71%	$ 141.23	$ 66.07	$ 6.00	$ 72.07	$ 213.30	90%	27.05	238.45	34.27	$ 6.71	-	-	4.51	72.54
Natural Gas																
Utility Cogeneration	5,076	10.12%	$ 513.46	$ 1.86	$ 0.50	$ 2.36	$ 515.82	82%	71.81	722.19	35.92	$ 23.29	4.17	-	8.87	144.06
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	722.19	52.44	$ 0.03	6.09	-	12.95	91.37
SCCT Aero	1,126	9.08%	$ 102.21	$ 9.95	$ 0.50	$ 10.45	$ 112.66	21%	61.24	722.19	70.58	$ 5.63	8.20	-	17.43	163.08
Intercooled Aero SCCT (Utah, 174MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	722.19	67.90	$ 2.71	7.89	-	16.77	149.62
Intercooled Aero SCCT (Utah, 261MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	722.19	67.90	$ 2.71	7.89	-	16.77	149.62
Intercooled Aero SCCT (Wyoming, 241MW)	1,140	9.08%	$ 103.50	$ 4.39	$ 0.50	$ 4.89	$ 108.38	21%	58.92	722.19	67.90	$ 2.94	6.83	-	16.77	153.36
Internal Combustion Engines	1,324	9.08%	$ 120.18	$ 12.80	$ 0.50	$ 13.30	$ 133.48	94%	16.21	722.19	61.38	$ 5.20	7.13	-	15.16	105.08
SCCT Frame (2 Frame "F")	747	8.62%	$ 64.39	$ 3.74	$ 0.50	$ 4.24	$ 68.62	21%	37.30	722.19	84.20	$ 4.47	9.78	-	20.79	156.55
SCCT Frame (2 Frame "F")	810	8.62%	$ 69.82	$ 4.05	$ 0.50	$ 4.55	$ 74.37	21%	40.43	722.19	84.20	$ 4.85	8.47	-	20.79	158.74
CCCT (Wet "F" 1x1)	1,366	8.59%	$ 117.32	$ 12.79	$ 0.50	$ 13.29	$ 130.61	56%	26.62	722.19	52.73	$ 2.94	6.13	-	13.02	101.45
CCCT Duct Firing (Wet "F" 1x1)	558	8.59%	$ 47.88	$ 1.60	$ 0.50	$ 2.10	$ 49.98	16%	35.66	722.19	64.05	$ 0.39	7.44	-	15.82	123.36
CCCT (Wet "F" 2x1)	1,244	8.59%	$ 106.79	$ 7.77	$ 0.50	$ 8.27	$ 115.06	56%	23.46	722.19	51.26	$ 2.94	5.96	-	12.66	96.27
CCCT Duct Firing (Wet "F" 2x1)	628	8.59%	$ 53.88	$ 1.60	$ 0.50	$ 2.10	$ 55.98	16%	39.94	722.19	61.80	$ 0.39	7.18	-	15.26	124.57
CCCT (Dry "F" 2x1)	1,275	8.59%	$ 109.50	$ 9.69	$ 0.50	$ 10.19	$ 119.70	56%	24.40	722.19	53.21	$ 3.35	6.18	-	13.14	100.28
CCCT Duct Firing (Dry "F" 2x1)	644	8.59%	$ 55.25	$ 1.60	$ 0.50	$ 2.10	$ 57.35	16%	40.91	722.19	64.63	$ 0.11	7.51	-	15.96	129.13
CCCT (Wet "G" 1x1)	1,292	8.59%	$ 110.93	$ 6.75	$ 0.50	$ 7.25	$ 118.18	56%	24.09	722.19	49.72	$ 4.56	5.78	-	12.28	96.42
CCCT Duct Firing (Wet "G" 1x1)	547	8.59%	$ 46.96	$ 1.63	$ 0.50	$ 2.13	$ 49.09	16%	35.03	722.19	65.15	$ 0.36	7.57	-	16.09	124.19
CCCT Advanced (Wet)	1,427	8.59%	$ 122.49	$ 6.75	$ 0.50	$ 7.25	$ 129.74	56%	26.45	722.19	48.82	$ 4.56	5.67	-	12.06	97.55
CCCT Advanced Duct Firing (Wet)	700	8.59%	$ 60.10	$ 1.63	$ 0.50	$ 2.13	$ 62.24	16%	44.40	722.19	65.15	$ 0.36	7.57	-	16.09	133.57
Other Renewables																
East (Wyoming) Wind (35% CF)	2,566	8.72%	$ 223.58	$ 31.43	$ 0.50	$ 31.93	$ 255.51	35%	83.34	-	-	-	11.75	(20.70)	-	74.38
East Side Geothermal (Blundell)	6,087	7.42%	$ 451.64	$ 110.85	$ 0.50	$ 111.35	$ 562.99	90%	71.41	-	-	$ 5.94		(20.70)	-	56.64
East Side Geothermal (Green Field)	7,608	7.42%	$ 564.55	$ 221.70	$ 0.50	$ 222.20	$ 786.74	90%	99.79	-	-	$ 11.88		(20.70)	-	90.97
Battery Storage	2,084	8.29%	$ 172.77	$ 1.00	$ 0.50	$ 1.50	$ 174.27	21%	94.73	722.19	86.66	$ 10.00	10.07	-	37.33	238.79
Pumped Storage	1,773	8.19%	$ 145.14	$ 4.30	$ 1.35	$ 5.65	$ 150.79	20%	86.06	722.19	93.88	$ 4.30	10.91	-	40.44	235.60
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.80	$ 1.35	$ 5.15	$ 134.56	47%	32.89	722.19	86.52	$ 5.50	8.70	-	21.37	154.98
Recovered Energy Generation (CHP)	5,500	9.39%	$ 516.67	$ 91.92	-	$ 91.92	$ 608.59	84%	82.71	-	-	-	-	-	-	82.71
Nuclear	5,461	8.30%	$ 453.26	$ 146.70	$ 6.00	$ 152.70	$ 605.95	85%	81.38	113.98	12.21	$ 1.63	-	-	-	95.22
Solar Concentrating (PV) - 30% CF	6,520	6.48%	$ 422.43	$ 180.00	$ 6.00	$ 186.00	$ 608.43	30%	231.52	-	-	-	-	(1.59)	-	229.93
Solar Concentrating (natural gas backup) - 25% solar	4,150	6.48%	$ 268.88	$ 195.60	$ 6.00	$ 201.60	$ 470.48	33%	162.75	722.19	19.59	-	2.28	(1.59)	4.84	187.86
Solar Concentrating (thermal storage) - 30% solar	4,650	5.46%	$ 253.80	$ 139.50	$ 6.00	$ 145.50	$ 399.30	30%	151.94	-	-	-	-	(1.59)	-	150.35

Table 6.7 – Total Resource Cost for West Side Supply-Side Resource Options, $45 CO_2 Tax

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs				Total
			Annual	Fixed O&M $/kW-Yr								mills/kWh				Resource
	Total	Payment	Payment				Total Fixed	Capacity Factor	Total Fixed	Levelized Fuel						Cost
Description	Capital Cost	Factor	($/kW-Yr)	O&M	Other	Total	($/kW-Yr)		Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	(Mills/kWh)
West Side Options (1500')																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	869.90	63.17	$ 0.03	5.33	-	12.95	101.33
SCCT Aero	1,024	9.08%	$ 92.92	$ 9.04	$ 0.50	$ 9.54	$ 102.46	21%	55.70	869.90	85.02	$ 5.12	7.17	-	17.43	170.43
Intercooled Aero SCCT	956	9.08%	$ 86.77	$ 3.68	$ 0.50	$ 4.18	$ 90.95	21%	49.44	869.90	81.79	$ 2.46	6.90	-	16.77	157.36
Internal Combustion Engines	1,204	9.08%	$ 109.25	$ 12.80	$ 0.50	$ 13.30	$ 122.55	94%	14.88	869.90	73.94	$ 5.20	6.24	-	15.16	115.42
SCCT Frame (2 Frame "F")	679	8.62%	$ 58.53	$ 3.40	$ 0.50	$ 3.90	$ 62.43	21%	33.94	869.90	101.43	$ 4.07	8.56	-	20.79	168.78
CCCT (Wet "F" 1x1)	1,242	8.59%	$ 106.66	$ 11.62	$ 0.50	$ 12.12	$ 118.78	56%	24.21	869.90	63.52	$ 2.67	5.36	-	13.02	108.79
CCCT Duct Firing (Wet "F" 1x1)	507	8.59%	$ 43.53	$ 1.45	$ 0.50	$ 1.95	$ 45.48	16%	32.45	869.90	77.15	$ 0.36	6.51	-	15.82	132.28
CCCT (Wet "F" 2x1)	1,131	8.59%	$ 97.08	$ 7.07	$ 0.50	$ 7.57	$ 104.65	56%	21.33	869.90	61.75	$ 2.67	5.21	-	12.66	103.62
CCCT Duct Firing (Wet "F" 2x1)	570	8.59%	$ 48.98	$ 1.45	$ 0.50	$ 1.95	$ 50.93	16%	36.34	869.90	74.44	$ 0.36	6.28	-	15.26	132.68
CCCT (Wet "G" 1x1)	1,175	8.59%	$ 100.85	$ 6.13	$ 0.50	$ 6.63	$ 107.48	56%	21.91	869.90	59.89	$ 4.14	5.05	-	12.28	103.27
CCCT Duct Firing (Wet "G" 1x1)	497	8.59%	$ 42.69	$ 1.48	$ 0.50	$ 1.98	$ 44.68	16%	31.88	869.90	78.48	$ 0.33	6.62	-	16.09	133.39
CCCT Advanced (Wet)	1,297	8.59%	$ 111.36	$ 6.13	$ 0.50	$ 6.63	$ 117.99	56%	24.05	869.90	58.80	$ 4.14	4.96	-	12.06	104.01
CCCT Advanced Duct Firing (Wet)	636	8.59%	$ 54.64	$ 1.48	$ 0.50	$ 1.98	$ 56.62	16%	40.40	869.90	78.48	$ 0.33	6.62	-	16.09	141.91
Other - Renewables																
West Wind	2,612	8.72%	$ 227.59	$ 31.43	$ 27.74	$ 59.17	$ 286.76	29%	112.88	-	-	-	11.75	(20.70)	-	103.93
Biomass	3,347	8.10%	$ 271.22	$ 38.80	$ 0.50	$ 39.30	$ 310.52	91%	38.78	590.00	64.78	$ 0.96	-	(20.70)	34.16	117.97
West Side Geothermal (Green Field)	7,609	7.42%	$ 564.62	$ 221.70	$ 0.50	$ 222.20	$ 786.82	90%	99.80	-	-	$ 11.88	-	(20.70)	-	90.98
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.45	$ 1.35	$ 4.80	$ 134.21	47%	32.81	869.90	104.21	$ 5.00	8.79	-	21.37	172.18
Hydrokinetic (Wave) - 21% CF	6,000	9.69%	$ 581.58	$ 180.00	$ 6.00	$ 186.00	$ 767.58	21%	417.25	-	-	-	-	-	-	417.25
West Side Options (Sea Level)																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	869.90	63.17	$ 0.03	5.33	-	12.95	101.33
SCCT Aero	972	9.08%	$ 88.27	$ 8.59	$ 0.50	$ 9.09	$ 97.36	21%	52.93	869.90	85.02	$ 4.87	7.17	-	17.43	167.42
Intercooled Aero SCCT	908	9.08%	$ 82.43	$ 3.49	$ 0.50	$ 3.99	$ 86.43	21%	46.98	869.90	81.79	$ 2.35	6.90	-	16.77	154.78
Internal Combustion Engines	1,143	9.08%	$ 103.79	$ 12.80	$ 0.50	$ 13.30	$ 117.09	94%	14.22	869.90	73.94	$ 5.20	6.24	-	15.16	114.75
SCCT Frame (2 Frame "F")	645	8.62%	$ 55.61	$ 3.23	$ 0.50	$ 3.73	$ 59.34	21%	32.26	869.90	101.43	$ 3.87	8.56	-	20.79	166.90
CCCT (Wet "F" 1x1)	1,180	8.59%	$ 101.32	$ 11.07	$ 0.50	$ 11.57	$ 112.89	56%	23.01	869.90	63.52	$ 2.55	5.36	-	13.02	107.46
CCCT Duct Firing (Wet "F" 1x1)	482	8.59%	$ 41.35	$ 1.38	$ 0.50	$ 1.88	$ 43.23	16%	30.85	869.90	77.15	$ 0.34	6.51	-	15.82	130.66
CCCT (Wet "F" 2x1)	1,074	8.59%	$ 92.23	$ 6.73	$ 0.50	$ 7.23	$ 99.46	56%	20.27	869.90	61.75	$ 2.55	5.21	-	12.66	102.44
CCCT Duct Firing (Wet "F" 2x1)	542	8.59%	$ 46.53	$ 1.38	$ 0.50	$ 1.88	$ 48.42	16%	34.54	869.90	74.44	$ 0.34	6.28	-	15.26	130.87
CCCT (Wet "G" 1x1)	1,116	8.59%	$ 95.81	$ 5.84	$ 0.50	$ 6.34	$ 102.15	56%	20.82	869.90	59.89	$ 3.94	5.05	-	12.28	101.98
CCCT Duct Firing (Wet "G" 1x1)	472	8.59%	$ 40.56	$ 1.41	$ 0.50	$ 1.91	$ 42.47	16%	30.30	869.90	78.48	$ 0.31	6.62	-	16.09	131.80
CCCT Advanced (Wet)	1,232	8.59%	$ 105.79	$ 5.84	$ 0.50	$ 6.34	$ 112.13	56%	22.86	869.90	58.80	$ 3.94	4.96	-	12.06	102.62
CCCT Advanced Duct Firing (Wet)	605	8.59%	$ 51.91	$ 1.41	$ 0.50	$ 1.91	$ 53.82	16%	38.40	869.90	78.48	$ 0.31	6.62	-	16.22	140.03

Distributed Generation

Table 6.8 reports cost and performance attributes for small distributed standby generation, combined heat and power, and on-site solar supply-side resource options. Tables 6.9 and 6.10 present the total resource cost attributes for these resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2008 dollars. The resource costs are presented for both the \$8 and \$45 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs. Certain technologies were adjusted to reflect benefits that were identified outside of the Quantec DSM potential study and cost of emissions. Maintenance and forced outage data were taken from comparable technologies in the supply-side table. Additional explanatory notes for the tables are as follows:

- A 15-percent administrative cost (for fixed operation and maintenance) is included in the overall cost of the resources.
- The avoided transmission and distribution credit of \$23/kW-year is included in the resource costs to reflect a rough estimate of savings by avoiding transmission and distribution investments.
- Federal tax benefits are included for microturbines at \$200/kW capacity, while fuel cells receive \$500 per 0.05 kW of capacity.
- Installation costs for on-site ("micro") solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. However, capital costs are adjusted downward to reflect federal and state tax benefits. The percentages applied included an 80 percent reduction to capital cost for Oregon, 31 percent for Utah, and 25 percent for all other states. The Quantec DSM potential study included the following benefits for commercial and residential customers:
  - Utah
    - *Commercial Credits:* The federal credit is 30 percent of the investment; the state credit is 1 percent of investment
    - *Residential Credits:* The federal credit is 30 percent of the investment up to \$2,000 for Residential Energy Efficiency; Utah receives up to \$2,000
  - Oregon
    - *Commercial Credits:* The federal credit is 30 percent of the investment; the state Business Credit is 50 percent of investment up to \$20 million received over 5 years; The Energy Trust of Oregon credit is \$1.25 per watt
    - *Residential Credits:* The federal credit is 30 percent of the investment up to \$2,000 for Residential Energy Efficiency; the state credit is 5 percent of investment; the Energy Trust of Oregon credit is \$2 per watt
  - Other States
    - *Commercial Credits:* The federal credit is 30 percent of the investment
    - *Residential Credits*: The federal credit is 30 percent of the investment up to \$2,000 for Residential Energy Efficiency

- The resource cost for Industrial Biomass reflects the Company's recent avoided cost, which reflects the minimum price the Company would pay. Factoring in the income tax benefits would lower the resource cost below the Company's avoided cost.

Table 6.8 – Distributed Generation Resource Options

(2008 Dollars)

Description	Installation Location	1st Year Avail.	Unit Size MW Average Cap. (MW)	Fuel	Design Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Capital Cost $/kW	Var. O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emissions SO2	NOx	Hg	CO2
												lbs/MMBTU (Hg: lbs/Tbtu)			
Small Combined Heat & Power															
Reciprocating Engine	Utah	2008	0.6	Natural Gas	20	5,005	2%	3%	$ 1,969	-	$ 79.00	0.001	0.101	0.255	118.00
Reciprocating Engine	Wyoming	2008	0.6	Natural Gas	20	5,005	2%	3%	$ 1,969	-	$ 79.00	0.001	0.101	0.255	118.00
Reciprocating Engine	Oregon	2008	0.6	Natural Gas	20	5,005	2%	3%	$ 1,969	-	$ 79.00	0.001	0.101	0.255	118.00
Gas Turbine	Utah	2008	3.2	Natural Gas	20	6,600	2%	3%	$ 1,838	-	$ 58.00	0.001	0.050	0.255	118.00
Gas Turbine	Wyoming	2008	3.2	Natural Gas	20	6,600	2%	3%	$ 1,838	-	$ 58.00	0.001	0.050	0.255	118.00
Gas Turbine	Oregon	2008	3.2	Natural Gas	20	6,600	2%	3%	$ 1,838	-	$ 58.00	0.001	0.050	0.255	118.00
Microturbine	Utah	2008	0.2	Natural Gas	15	7,454	2%	3%	$ 2,831	-	$ 71.00	0.001	0.101	0.255	118.00
Microturbine	Wyoming	2008	0.2	Natural Gas	15	7,454	2%	3%	$ 2,831	-	$ 71.00	0.001	0.101	0.255	118.00
Microturbine	Oregon	2008	0.2	Natural Gas	15	7,454	2%	3%	$ 2,831	-	$ 71.00	0.001	0.101	0.255	118.00
Fuel Cell	Utah	2008	0.5	Natural Gas	10	5,706	2%	3%	$ 5,697	-	$ 17.00	0.001	0.003	0.255	118.00
Fuel Cell	Wyoming	2008	0.5	Natural Gas	10	5,706	2%	3%	$ 5,697	-	$ 17.00	0.001	0.003	0.255	118.00
Fuel Cell	Oregon	2008	0.5	Natural Gas	10	5,706	2%	3%	$ 5,697	-	$ 17.00	0.001	0.003	0.255	118.00
Commercial Biomass, Anaerobic Digester	Utah	2008	0.4	Biomass	15	-	10%	10%	$ 3,219	-	$ 67.00	-	-	-	-
Commercial Biomass, Anaerobic Digester	Wyoming	2008	0.4	Biomass	15	-	10%	10%	$ 3,219	-	$ 67.00	-	-	-	-
Commercial Biomass, Anaerobic Digester	Oregon	2008	0.4	Biomass	15	-	10%	10%	$ 3,219	-	$ 67.00	-	-	-	-
Industrial Biomass, Waste	Utah	2008	4.8	Biomass	15	-	5%	5%	$ 1,800	-	$ 39.00	-	-	-	-
Industrial Biomass, Waste	Wyoming	2008	4.8	Biomass	15	-	5%	5%	$ 1,800	-	$ 39.00	-	-	-	-
Industrial Biomass, Waste	Oregon	2008	4.8	Biomass	15	-	5%	5%	$ 1,800	-	$ 39.00	-	-	-	-
Solar															
Rooftop Photovoltaic	Utah	2008	0.005	Solar	25	-			$ 9,000	-	$ 100.00	-	-	-	-
Rooftop Photovoltaic	Wyoming	2008	0.005	Solar	25	-			$ 9,000	-	$ 100.00	-	-	-	-
Rooftop Photovoltaic	Oregon	2008	0.005	Solar	25	-			$ 9,000	-	$ 100.00	-	-	-	-
Water Heaters	Utah	2008	0.002	Solar	15	-			$ 3,500	-	-	-	-	-	-
Water Heaters	Wyoming	2008	0.002	Solar	15	-			$ 3,500	-	-	-	-	-	-
Water Heaters	Oregon	2008	0.002	Solar	15	-			$ 3,500	-	-	-	-	-	-
Attic Fans	Utah	2008	0.000010	Solar	10	-			$ 54,000	-	-	-	-	-	-
Attic Fans	Wyoming	2008	0.000010	Solar	10	-			$ 54,000	-	-	-	-	-	-
Attic Fans	Oregon	2008	0.000010	Solar	10	-			$ 54,000	-	-	-	-	-	-
Dispatchible Generators															
Dispatchible Standby Generators Existing	Utah	2008	1.0	Diesel	20	9,975			$ 250	-	$ 7.50	0.030	0.101	0.255	118.00
Dispatchible Standby Generators Existing	Wyoming	2008	1.0	Diesel	20	9,975			$ 250	-	$ 7.50	0.030	0.101	0.255	118.00
Dispatchible Standby Generators Existing	Oregon	2008	1.0	Diesel	20	9,975			$ 250	-	$ 7.50	0.030	0.101	0.255	118.00
Dispatchible Standby Generators New	Utah	2008	1.0	Diesel	20	9,975			$ 175	-	$ 5.00	0.030	0.101	0.255	118.00
Dispatchible Standby Generators New	Wyoming	2008	1.0	Diesel	20	9,975			$ 175	-	$ 5.00	0.030	0.101	0.255	118.00
Dispatchible Standby Generators New	Oregon	2008	1.0	Diesel	20	9,975			$ 175	-	$ 5.00	0.030	0.101	0.255	118.00

Table 6.9 – Distributed Generation Total Resource Costs, \$8 CO_2 tax

(2008 Dollars)

	Capital Cost $/kW							Fixed Cost				Convert to Mills				Variable Costs			Total
						Payment	Annual Pmt	Fixed O&M $/kW-Yr			Total Fixed	Capacity	Ttl Fixed	Levelized Fuel		mills/kWh			Resource Cost
Description	Cap Cost	Tax Benefits	Transmission & Distribution Credit	Administrative	Net Capital Costs	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Factor	Mills/kWh	¢/mmBtu	Mills/kWh	O&M	Avoided Cost	Environmental	(Mills/kWh)
Small Combined Heat & Power																			
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	699.22	35.00	-	-	1.59	$ 76.04
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	699.22	35.00	-	-	1.59	$ 76.04
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	814.00	40.74	-	-	1.59	$ 81.79
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	699.22	46.15	-	-	2.09	$ 81.06
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	699.22	46.15	-	-	2.09	$ 81.06
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	814.00	53.72	-	-	2.09	$ 88.63
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	699.22	52.12	-	-	2.36	$ 104.78
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	699.22	52.12	-	-	2.36	$ 104.78
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	814.00	60.68	-	-	2.36	$ 113.33
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	699.22	39.90	-	-	1.81	$ 140.81
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	699.22	39.90	-	-	1.81	$ 140.81
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	814.00	46.45	-	-	1.81	$ 147.36
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	46.30	-	$ 46.30
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	58.37	-	$ 58.37
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	62.33	-	$ 62.33
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	46.30	-	$ 46.30
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	58.37	-	$ 58.37
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	62.33	-	$ 62.33
Solar																			
Rooftop Photovoltaic	$ 9,000	$ (2,790)	$ (264)	$ 1,350	$ 7,296	8.72%	$ 635.85	$ 100.00	-	$ 100.00	$ 735.85	14%	600.01	-	-	-	-	-	$ 600.01
Rooftop Photovoltaic	$ 9,000	$ (2,250)	$ (264)	$ 1,350	$ 7,836	8.72%	$ 682.92	$ 100.00	-	$ 100.00	$ 782.92	14%	638.38	-	-	-	-	-	$ 638.38
Rooftop Photovoltaic	$ 9,000	$ (7,200)	$ (264)	$ 1,350	$ 2,886	8.72%	$ 251.52	$ 100.00	-	$ 100.00	$ 351.52	13%	308.68	-	-	-	-	-	$ 308.68
Water Heaters	$ 3,500	$ (980)	$ (202)	$ 525	$ 2,843	11.41%	$ 324.31	-	-	-	$ 324.31	14%	264.44	-	-	-	-	-	$ 264.44
Water Heaters	$ 3,500	$ (875)	$ (202)	$ 525	$ 2,948	11.41%	$ 336.29	-	-	-	$ 336.29	14%	274.21	-	-	-	-	-	$ 274.21
Water Heaters	$ 3,500	$ (1,330)	$ (202)	$ 525	$ 2,493	11.41%	$ 284.39	-	-	-	$ 284.39	13%	249.73	-	-	-	-	-	$ 249.73
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$9,269.64	13%	8139.83	-	-	-	-	-	$ 8,139.83
Dispatchible Generators																			
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	3.19	$ 471.26
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	3.19	$ 471.26
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	3.19	$ 471.26
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	3.19	$ 318.01
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	3.19	$ 318.01
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	3.19	$ 318.01

Table 6.10 – Distributed Generation Total Resource Cost, $45 CO_2 Tax

(2008 Dollars)

	Capital Cost $/kW							Fixed Cost				Convert to Mills				Variable Costs mills/kWh			Total
						Payment	Annual Pmt	Fixed O&M $/kW-Yr			Total Fixed	Capacity	Ttl Fixed	Levelized Fuel					Resource Cost
Description	Cap Cost	Tax Benefits	Transmission & Distribution Credit	Administrative	Net Capital Costs	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Factor	Mills/kWh	¢/mmBtu	Mills/kWh	O&M	Avoided Cost	Environmental	(Mills/kWh)
Small Combined Heat & Power																			
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	722.19	36.15	-	-	8.93	$ 84.53
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	722.19	36.15	-	-	8.93	$ 84.53
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	869.90	43.54	-	-	8.93	$ 91.92
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	722.19	47.66	-	-	11.77	$ 92.25
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	722.19	47.66	-	-	11.77	$ 92.25
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	869.90	57.41	-	-	11.77	$ 102.00
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	722.19	53.83	-	-	13.29	$ 117.42
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	722.19	53.83	-	-	13.29	$ 117.42
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	869.90	64.84	-	-	13.29	$ 128.43
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	722.19	41.21	-	-	10.18	$ 150.49
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	722.19	41.21	-	-	10.18	$ 150.49
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	869.90	49.64	-	-	10.18	$ 158.92
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	46.30	-	$ 46.30
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	58.37	-	$ 58.37
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	62.33	-	$ 62.33
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	46.30	-	$ 46.30
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	58.37	-	$ 58.37
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	62.33	-	$ 62.33
Solar																			
Rooftop Photovoltaic	$ 9,000	$ (2,790)	$ (264)	$ 1,350	$ 7,296	8.72%	$ 635.85	$ 100.00	-	$ 100.00	$ 735.85	14%	600.01	-	-	-	-	-	$ 600.01
Rooftop Photovoltaic	$ 9,000	$ (2,250)	$ (264)	$ 1,350	$ 7,836	8.72%	$ 682.92	$ 100.00	-	$ 100.00	$ 782.92	14%	638.38	-	-	-	-	-	$ 638.38
Rooftop Photovoltaic	$ 9,000	$ (7,200)	$ (264)	$ 1,350	$ 2,886	8.72%	$ 251.52	$ 100.00	-	$ 100.00	$ 351.52	13%	308.68	-	-	-	-	-	$ 308.68
Water Heaters	$ 3,500	$ (980)	$ (202)	$ 525	$ 2,843	11.41%	$ 324.31	-	-	-	$ 324.31	14%	264.44	-	-	-	-	-	$ 264.44
Water Heaters	$ 3,500	$ (875)	$ (202)	$ 525	$ 2,948	11.41%	$ 336.29	-	-	-	$ 336.29	14%	274.21	-	-	-	-	-	$ 274.21
Water Heaters	$ 3,500	$ (1,330)	$ (202)	$ 525	$ 2,493	11.41%	$ 284.39	-	-	-	$ 284.39	13%	249.73	-	-	-	-	-	$ 249.73
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$ 9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$ 9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$ 9,269.64	13%	8139.83	-	-	-	-	-	$ 8,139.83
Dispatchible Generators																			
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	17.81	$ 485.88
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	17.81	$ 485.88
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	17.81	$ 485.88
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	17.81	$ 332.63
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	17.81	$ 332.63
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	17.81	$ 332.63

Resource Option Description

Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical pulverized coal boilers (PC) and integrated gasification combined cycles (IGCC) in Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have risen by approximately 50% to 60% due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. Additionally the uncertainty of future carbon regulations and a difficulty in obtaining construction and environmental permits for coal based generation alternatives has encouraged the Company to postpone the selection of coal as a resource before 2020.

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

Carbon dioxide capture and sequestration technology represents a potential cost for new and existing coal plants if future regulations require it. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from the flue gas of conventional boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would bury the CO_2 underground for long-term storage and monitoring.

PacifiCorp and its parent Company MEHC are monitoring CO_2 capture technologies for possible retrofit opportunities at its existing coal-fired fleet, as well as applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO_2 removal becomes necessary in the future. An option to capture CO_2 at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a couple of large-scale sequestration projects in operation around the world and a number of these are in conjunction with enhanced oil recovery. Carbon capture and sequestration (CCS) is not considered a viable option before 2025 due to risk issues associated with technological maturity and underground sequestration liability.

An alternative to supercritical pulverized-coal technology for coal-based generation would be the use of IGCC technology. A significant advantage for IGCC when compared to conventional pulverized coal with amine-based carbon capture is the reduced cost of capturing carbon dioxide from the process. Gasification plants have been built and demonstrated around the world, primarily as a means of producing chemicals from coal. Only a limited number of IGCC plants have been constructed specifically for power generation. In the United States, these facilities have been demonstration projects and cost significantly more than conventional coal plants in both capital and operating costs. These projects have been constructed with significant funding from the federal government. A number of IGCC technology suppliers have teamed up with large constructor to form consortia who are now offering to build IGCC plants. A few years ago, these consortia were willing to provide IGCC plants on a lump-sum, turn-key basis. However, in today's market, the willingness of these consortia to design and construct IGCC plants on lump-sum turn key basis is in question. The costs presented in the supply-side resource options tables reflect recent studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp was selected by the Wyoming Infrastructure Authority (WIA) to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal was to develop a Section 413 project under the 2005 Energy Policy Act. PacifiCorp commissioned and managed feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Based on the results of initial feasibility studies, PacifiCorp declined to submit a proposal to the federal agencies involved in the Section 413 solicitation.

PacifiCorp is a member of the Gasification User's Association. In addition, PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables. Over the last two years PacifiCorp has help a series of public meetings as a part of an IGCC Working Group to help provide a broader level of understanding for this technology.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants (which are manifest in lower plant heat rates) are realized by (1) emphasizing continuous improvement in operations, and (2) upgrading components if economically justified. Such fuel efficiency improvements can result in a smaller emission footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units degrades gradually as components wear out over time. During operation, controllable process parameters are adjusted to optimize unit output and efficiency. Typical overhaul work that contributes to improved efficiency includes (1) steam turbine overhauls, (2) cleaning and repairing condensers, feed water heaters, and cooling towers and (3) cleaning boiler heat transfer surfaces.

When economically justified, efficiency improvements are obtained through major component upgrades. Examples include turbine upgrades using new blade and sealing technology, improved seals and heat exchange elements for boiler air heaters, cooling tower fill upgrades, and the addition of cooling tower cells. Such upgrade opportunities are analyzed on a case by case basis, and it is difficult to plan far in advance since decisions are tied to the existence of commercially-proven technology advancements available during a plant's next major overhaul cycle. PacifiCorp is taking advantage of improved upgrade technology through its "dense pack" coal plant turbine upgrade initiative. This initiative, to be completed by 2016, is factored into the 2008 IRP via a 170 MW coal plant capacity gain without a corresponding increase in fuel consumption, heat input, or emissions. Capacity expansion modeling to support the 2008 business plan indicated that this upgrade initiative was cost-effective. This resource is included in the current IRP models as a result.

Natural Gas

Natural gas generation options are numerous and a limited number of representative technologies are included in the supply-side resource options table. Simple cycle and combined cycle combustion turbines are included. A dry cooled combined cycle has been included. As with other generation technologies, the cost of natural gas generation has increased substantially from previous IRPs. Costs for gas generation have increased by 40% to 70%, depending on the option, due not only to general utility cost issues mentioned earlier, but also due to the decrease in coal-based projects thereby putting an increased demand on natural gas options that can be more easily permitted.

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

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

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of 14 machines at 10.9 megawatts. These machines are spark-ignited and have the advantages of a relatively attractive heat rate, a low emissions profile, and a high level of availability and reliability due to the number of machines. At present, fuel cells hold less promise due to high capital cost, partly attributable to the lack of production capability and continued development. Fuel cells are not ready for large scale deployment and are not considered available as a supply-side option until after 2013.

Combined cycle power plants options have been limited to 1x1 and 2x1 applications of “F” style combustion turbines and a “G” 1x1 facility. The “F” style machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the portfolio planning. Similarly, the “G” machine has been added to take advantage of the improved heat rate available from these more advanced gas turbines. The “G” machine is only presented as a 1x1 option to keep the size of the facility reasonable for selection as a portfolio option. These natural gas technologies are considered mature and installation lead times and capital costs are well known. The capital cost pressure currently being observed with constructing large coal-based generation plants is also being experienced with natural gas-fired plants.

Wind

Representation of wind projects was accomplished by developing a set of proxy wind sites composed of 100-MW blocks that could be selected as distinct resource options in the System Optimizer model. (Note that the 100-megawatt size reflects a suitable average size for modeling purposes, and does not imply that acquisitions are of this size.) Table 6.11 shows the regions in which wind resources are located and the representative capacity factors and quantity limits available to the System Optimizer model for selection. Note that these are aggregate limits for the entire modeling simulation period.

Table 6.11 – Proxy Wind Sites and Characteristics

Transmission Bubble	Location	Capacity Factor (%)	Maximum Capacity (MW)
Southwest Wyoming	Southwest Wyoming	24	1,400
		29	1,300
		35	1,300
Northeast Wyoming	Northeast Wyoming	24	1,400
		29	1,300
		35	1,300
Wyoming (Aeolus substation)	Southwest Wyoming	24	500
		29	500
		35	500
Goshen	Southeast Idaho	24	300
		29	300
Walla Walla	Southeast Washington	24	200
		29	300
		35	300
Yakima	South Central Washington	24	300
		29	200
West Main	Central Oregon	24	700
		29	500
		35	100
Mid-Columbia	Southwest Washington	24	100
		29	100
		35	100
Utah	Northern Utah	24	200
		29	200

For other wind resource attributes, the Company used multiple sources to derive attributes. Capital costs were derived from recent PacifiCorp projects and offers by developers. The EPRI TAG database was also used for certain cost figures, such as operation and maintenance costs. These costs were adjusted for current market conditions. Wheeling costs, applicable for wind projects cited in the west, and average incremental transmission costs for east-side resources needed beyond local interconnection and 230 kV step-up were included in the resources as appropriate.

Other Renewable Resources

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

Geothermal

The geothermal resources in Tables 6.2 and 6.3 represent a dual flash design with a wet cooling tower. The 35 MW values per project are suggested by engineering studies associated with a third unit at the Blundell site using technology similar to the Company's existing geothermal resources. The expansion of the Blundell site represents the best cost for geothermal energy currently available to the Company. Speculative risks associated with steam field development, as well as recent escalation in drilling costs, are not captured in the geothermal cost characterization.

The Company chose 100 MW as a reasonable upper bound for geothermal resource additions based on its experience with locating sizable quantities of geothermal generation either under development or suitable for development. Considerations included the Company's current view of realistic commercial resource opportunities given issues with project locations (development in sensitive areas and local opposition) and well performance related to temperature and resource adequacy as reported in recent geologic studies. Using the 35-MW representative size for a geothermal project yields a total of three geothermal projects as resource options, for a total of 105 MW. The Company has not yet conducted a geothermal commercial potential study looking at long-term prospects for geothermal energy utilizing both Blundell technology and other alternative geothermal technologies. One of the fundamental barriers to geothermal development is the difficulty in characterizing the type, quality, and conditions of a particular geothermal resource. This characterization requires a significant investment for well drilling and testing in order to develop a reliable and provable assessment.

Biomass and Solar

The biomass project would involve the combustion of whole trees that would be grown in a plantation setting, presumably in the Pacific Northwest. Three solar resources were defined. A concentrating photovoltaic (PV) system represents a utility scale PV resource. Optimistic performance and cost figures were used equivalent to the best reported PV efficiencies. Solar thermal projects are represented by both a solar concentrating design (trough system with natural gas backup) and a solar concentrating design (thermal tower arrangement with 6 hours of thermal storage). The system parameters for these systems were suggested by the WorleyParsons Group study and reflect current proposed projects in the desert southwest.

Energy Storage

The storage of energy is represented in the supply-side resource options table with three systems. The three systems are advanced battery applications, pumped hydro and compressed air energy storage. These technologies convert off-peak capacity to on-peak energy and thereby reduce the quantity of required overall capacity installed for peaking needs. Battery applications are typically smaller systems (less than 10 megawatts) that can have the most benefit in a smaller local area. Utility-scale demonstrations are just beginning to be conducted. Advanced battery applications are not available for selection in the modeling before 2014.

Pumped hydro is dependent on a good site combined with the ability to permit the facility, a process that can take many years to accomplish. PacifiCorp does not have any specific pumped hydro projects under development and does not consider this a viable resource before 2018 because of the necessary study and permitting issues.

Compressed air energy storage (CAES) can be an attractive means of utilizing intermittent energy. In a CAES plant, off-peak energy is used to pressurize an underground cavern. The pressurized air would then feed the power turbine portion of a combustion turbine saving the energy normally used in combustion turbine to compress air. CAES plants operate on a simple cycle basis and therefore displace peaking resources. A CAES plant could be built in conjunction with wind resources to level the production for such an intermittent resource. A CAES plant, whether associated with wind or not, would have to stand on its own for cost-effectiveness. Only two CAES plants have been built in the world. CAES is not considered practical for PacifiCorp until 2015.

Combined Heat and Power and Other Distributed Generation Alternatives

CHP are a small (ten megawatts or less) gas compressor heat recovery system using a binary cycle. These projects would be contracted at the customer site. They are labeled as Recovered Energy Generation (CHP) and utility cogeneration in the supply-side table.

A large CHP (40 to 120 megawatts) combustion turbine with significant steam based heat recovery from the flue gas has not been included in PacifiCorp’s supply side table for the eastern service territory due to a lack of large potential industrial applications. These CHP opportunities are site-specific, and the generic options presented in the supply-side resource options table are not intended to represent any particular project or opportunity.

Small distributed generation resources are unique in that they reside at the customer load. The generation can either be used to reduce the customer load, such as net metering, or sold to the utility. Distributed standby generation provides peak load reductions over a contracted number of hours from on-site generators owned by the customer but managed by the utility. Small CHP resources generate electricity and utilize waste heat for space and water heating requirements. Fuel is either natural gas or renewable biogas. On-site solar resources, also referred to as “micro solar”, include electric generation and energy-efficiency measures that use solar energy. The DG resources are up to 4.8 MW in size.

Table 6.12 shows the megawatt economic potential for distributed standby generation cited in the DSM potential study and the amount of the resource included in the IRP models. Due to the small potential in PacifiCorp’s California, Yakima, Walla Walla, and Idaho service territories, these resources were excluded as model options. For distributed CHP, Tables 6.13 and 6.14 show the economic potential and amounts included in the IRP models, respectively. PacifiCorp used screening thresholds of 5 MW by state and 8 MW by technology to exclude resources from the IRP models. Such screening for small distributed generation resources was necessary to accommodate the large number of other resource options included in the IRP models. The size screening eliminated all but the West Main (Oregon and northern California) rooftop photovoltaic system.[30]

Table 6.12 – Standby Generation Economic Potential and Modeled Capacity

Year	Distributed Standby Generation (MW)					
	Cumulative Economic Potential			IRP Model Option		
	Existing	New	Total	Existing	New	Total
2009	6.9	9.9	16.8	5.7	9.5	15.2
2010	9.3	14.9	24.2	8.0	14.2	22.2
2011	11.8	19.9	31.6	10.3	18.9	29.2
2012	16.6	24.8	41.5	14.9	23.6	38.5
2013	21.5	29.8	51.3	19.4	28.4	47.8
2014	28.8	34.8	63.6	26.3	33.1	59.4
2015	36.1	39.7	75.9	33.1	37.8	71.0
2016	43.5	44.7	88.2	40.0	42.5	82.6
2017	50.8	49.7	100.5	46.9	47.3	94.1
2018	50.8	54.6	105.4	46.9	52.0	98.9
2019	50.8	59.6	110.4	46.9	56.7	103.6
2020	50.8	64.6	115.4	46.9	61.5	108.3
2021	50.8	69.5	120.3	46.9	66.2	113.0
2022	50.8	74.5	125.3	46.9	70.9	117.8
2023	50.8	79.5	130.3	46.9	75.6	122.5
2024	50.8	84.4	135.2	46.9	80.4	127.2
2025	50.8	89.4	140.2	46.9	85.1	132.0
2026	50.8	94.4	145.2	46.9	89.8	136.7
2027	50.8	99.3	150.1	46.9	94.6	141.4
2028	50.8	99.3	150.1	46.9	99.5	146.4

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[30] As a sensitivity test, the Company allowed its capacity expansion model to select from the entire set of micro-solar resources given the input assumptions from which the 2008 IRP preferred portfolio was derived. The model did not choose any micro-solar resources. This result is due to the higher fixed costs and lower availability relative to small competing resources such as CHP and DSM.

Table 6.13 – Distributed CHP Economic Potential (MW)

Year	Economic Potential (MW)									
	Combined Heat & Power (CHP)						On-Site Solar			Total
	Reciprocating Engine	MicroTurbine	Fuel Cell	Gas Turbine	Industrial Biomass	Anaerobic Digesters	Photovoltaic (PV)	Solar Water Heaters	Solar Attic Fans	
2009	0.3	0.0	0.0	0.0	0.4	0.0	0.2	0.0	0.0	1.1
2010	1.4	0.2	0.1	0.1	1.9	0.1	0.8	0.1	0.0	4.7
2011	3.0	0.4	0.2	0.2	4.1	0.3	1.6	0.2	0.1	10.0
2012	6.2	0.8	0.4	0.4	8.3	0.5	2.9	0.3	0.1	20.0
2013	10.5	1.3	0.7	0.7	14.2	0.9	4.3	0.4	0.2	33.2
2014	14.8	1.8	1.0	1.0	20.0	1.3	5.9	0.5	0.2	46.5
2015	19.1	2.4	1.3	1.3	25.8	1.6	7.4	0.7	0.3	59.9
2016	23.5	2.9	1.6	1.6	31.6	2.0	9.1	0.8	0.3	73.4
2017	27.8	3.4	1.9	1.9	37.5	2.4	10.7	0.9	0.3	86.8
2018	32.1	4.0	2.2	2.2	43.3	2.7	12.3	1.0	0.4	100.2
2019	36.4	4.5	2.5	2.5	49.1	3.1	13.6	1.1	0.4	113.3
2020	40.7	5.0	2.8	2.8	55.0	3.4	14.7	1.2	0.4	126.1
2021	45.1	5.6	3.1	3.1	60.8	3.8	15.7	1.2	0.5	138.8
2022	49.4	6.1	3.4	3.4	66.6	4.2	16.4	1.3	0.5	151.2
2023	53.1	6.5	3.7	3.6	71.6	4.5	17.0	1.3	0.5	161.9
2024	56.2	6.9	3.9	3.8	75.8	4.8	17.6	1.3	0.5	170.8
2025	58.0	7.2	4.0	3.9	78.3	4.9	18.0	1.3	0.5	176.2
2026	59.9	7.4	4.2	4.1	80.8	5.1	18.4	1.4	0.5	181.6
2027	61.7	7.6	4.3	4.2	83.3	5.2	18.8	1.4	0.5	187.1
2028	63.6	7.8	4.4	4.3	85.9	5.4	19.2	1.4	0.5	192.6

Table 6.14 – Distributed CHP Resources Included as IRP Model Options

Year	IRP Model Options (MW)			
	Combined Heat & Power (CHP)		On-Site (“Micro”) Solar	Total
	Reciprocating Engine	Industrial Biomass	Photovoltaic (PV)	
2009	0.3	0.3	0.2	0.8
2010	1.2	1.5	0.7	3.4
2011	2.7	3.2	1.4	7.2
2012	5.4	6.6	2.5	14.5
2013	9.2	11.1	3.7	24.1
2014	13.0	15.7	5.0	33.8
2015	16.8	20.3	6.4	43.6
2016	20.6	24.9	7.9	53.4
2017	24.4	29.5	9.2	63.2
2018	28.2	34.1	10.6	73.0
2019	32.1	38.7	11.8	82.5
2020	35.9	43.3	12.7	91.8
2021	39.7	47.8	13.5	101.0
2022	43.5	52.4	14.2	110.1
2023	46.7	56.4	14.7	117.8
2024	49.4	59.6	15.2	124.3
2025	51.1	61.6	15.5	128.2
2026	52.7	63.6	15.9	132.2
2027	54.3	65.5	16.3	136.1
2028	56.0	67.6	16.6	140.2

Nuclear

An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based recent internal studies, press reports and information from a paper prepared by the Uranium Information Centre Ltd., “The Economics of Nuclear Power,” May 2008. A 1,600 MW plant is characterized utilizing advanced nuclear plant designs. Nuclear power is not considered a viable option in the PacifiCorp service territory before 2025.

DEMAND-SIDE RESOURCES

Resource Options and Attributes

Source of Demand-side Management Resource Data

Demand-side resource opportunity estimates used in the development of the 2008 IRP were derived from data provided from the “Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources” study completed in June 2007 (DSM potential study). Preliminary results from the DSM potential study were initially incorporated in the 2007 IRP Update. However, these estimates were not modeled under the prescribed supply-curve methodology until the development of the 2008 IRP. The DSM potential study provided a broad estimate of the size, type, location and cost of demand-side resources. The demand-side resource information was converted into supply-curves by type of DSM; e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves

Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and costs of resources. Supply curves incorporate a linear relationship between quantities and costs (at least up to the maximum quantity available) to help identify at any particular cost how much of a particular resource can be acquired. Resource modeling utilizing supply curves allows utilities to sort out and select the least-cost resources (products and quantities) based on each resource’s cost versus quantity in comparison against the supply curves of alternative and competing resource types.

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to demand-side supply curves include:

- Resource quantities available in year one—either megawatts or megawatt-hours— recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year
- Resource quantities available over time; for example, Class 2 energy-based resource measure lives
- Seasonal availability and hours available (Class 1 and Class 3 capacity resources)
- The shape or hourly contribution of the resource (load shape of the Class 2 energy resource)
- Levelized resource costs (dollars per megawatt per year for Class 1 and 3 capacity resources, or dollars per megawatt-hour for Class 2 energy resources)

Once developed, demand-side resource supply curves are treated like any other discrete supply-side resource in the IRP modeling environment. A complicating factor for modeling is that the DSM supply curves must be configured to meet the input specifications for two models: the System Optimizer capacity expansion optimization model, and the Planning and Risk production cost simulation model.

Class 1 DSM Capacity Supply Curves

Supply curves were created for four discrete Class 1 DSM products: residential air conditioning load control, irrigation load control, dispatchable commercial curtailment, and commercial and industrial thermal energy storage. The potentials and costs for each product were provided at the state level resulting in four products across six states, or twenty-four supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of forty Class 1 DSM supply curves were used in the 2008 IRP modeling process.

The starting point for supply curve development was DSM product information originally used for PacifiCorp's 2007 IRP. This information was further refined based on the following:

- Updated costs
- Customer surveys and acceptance data from the DSM potential study information
- Adjustments to DSM potential study results based on amended assumptions
- Another years experience delivering Class 1 DSM products
- The 2007 IRP modeling results.

In developing information on the four products and creation of supply curves, assumption changes (from those used in the DSM potential study) were made to two of the four products. The net potential for irrigation load control in the east was increased, as was the cost, to recognize the percentage of customers expected to select a dispatchable control option over a scheduled firm control option. In a second case, a new Class 1 product was created in order to incorporate the potential from a Class 3 product, commercial curtailment, for base resource consideration. The product recognizes how the Company intends to pursue, through program design, available commercial control opportunities (e.g. leverage controllable commercial loads using customer energy management systems combined with contracts for utility dispatched operation of customer distributed standby generators.)

The potential and cost of the Class 3 commercial curtailment product was used to create the new Class 1 product for three reasons. First, the potential captured in the Class 3 product was assumed to come from customer control of end-use equipment, not from any distributed standby generation capabilities. Second, the potential for distributed standby generation was included in the IRP model as a supply-side resource option. (It is already captured as a model resource). Third, the levelized cost for the Class 3 commercial curtailment product is in the same range as the levelized cost for distributed standby generation; approximately \$50-\$60 per kilowatt per year.

Other product price differences between west and east control areas were driven by resource differences in each market, such as irrigation pump sizes, types of pumping, and product performance differences (for example, residential air conditioning load control in the west is nearly twice the cost of east-side programs due to climatic differences that lead to less control per installed switch.) Pricing is also impacted by resource opportunity differences. The DSM potential study assumed the same fixed costs regardless of quantify of a particular product available. Therefore, the weighted average cost per control area for products with less opportunity in a particular state have a higher cost per kilowatt-year for that product.

The combination residential air conditioning and electric water heating dispatchable load control product was not provided to the System Optimizer model as a resource option for either control area. In the west, electric water heating control wasn't included as it adds little additional load for the cost, and electric water heating market share continues to decline each year as a result of conversions to gas. In the east, electric water heating control wasn't included because (1) the market potential is very small. (It is predominantly a gas water heating market), (2) an established program already exists that doesn't include a water heater control component, and (3) the potential identified is assumed to be located in areas where gas is not available; such as more rural and mountainous areas where direct load control paging signals are less reliable.

Tables 6.15 and 6.16 show the summary level Class 1 DSM program information, by control area, used in the development of the Class 1 resources supply curves. As previously noted, each of the products were further broken down by quantity available by state and load area in order to provide the model with location-specific details.

Table 6.15 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential Air Conditioning	Yes, with combo AC & water heating	Summer 40, not to exceed 6 hours per day	June 1 to Sept. 15	11	$165	2009
Irrigation (50% dispatchable and 50% scheduled firm)	No	Summer 40, not to exceed 6 hours per day	June 1 to Sept. 15	20	$50	2009
Commercial Curtailment (combination dispatchable product, excludes DSG in potential but will include in program to design)	Yes, with C&I Direct Load Control, Thermal Energy Storage, demand buyback, critical peak pricing, real-time pricing, and distributed standby generation	Summer and winter 40, 80 hours total. Not to exceed 6 hours per day	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	5	$61	2009
Commercial Thermal Energy Storage		Summer 40	June 1 to Sept. 15	2	$150	2009

[1] These costs are before a credit of $23/KW-year is applied for avoided transmission and distribution investment costs.

Table 6.16 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential Air Conditioning	Yes, with combo AC & WH	Summer 40, not to exceed 6 hours per day	Jun 1 to Sept. 15	47	$93	2009
Irrigation (50% dispatchable and 50% scheduled firm)	No	Summer 40, not to exceed 6 hours per day	June 1 to Sept. 15	45	$57	2009
Commercial Curtailment (combination dispatchable product, excludes DSG in potential but will include in program to design)	Yes, with C&I Direct Load Control, Thermal Energy Storage, demand buyback, critical peak pricing, real-time pricing, and distributed standby generation	Summer and winter 40, 80 hours total. Not to exceed 6 hours per day	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	38	$59	2009
Commercial Thermal Energy Storage		Summer 40	June 1 to Sept. 15	7	$153	2009

[1] These costs are before a credit of $23/KW-year is applied for avoided transmission and distribution investment costs.

To configure the supply curves for use in the System Optimizer model, there are a number of data conversions and resource attributes that are required by the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in $/kW-month. A credit of $23/kW-year for avoided transmission and distribution investment costs is also applied against the cost.[31] The following are the primary model attributes required by the model:

- The Capacity Planning Factor (CPF): This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Class 1 and 3 DSM programs, this parameter is set to 1 (100 percent).
- Additional reserves: This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.
- Daily and annual energy limits: These parameters, expressed in gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.

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[31] The Northwest Power and Conservation Council (NWPCC) and the Energy Trust of Oregon (ETO) use this value for their DSM avoided cost calculations.

- Nameplate capacity (MW) and service life (years)
- Maximum Annual Units: This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- First year and month available/last year available
- Fractional Units First Year: This parameter tells the model the first year in which a fractional quantity of the resource (as opposed to an integer quantity) can be selected. Year 2008 is entered in order to make these DSM resource options fractionally available in all years.

After the model has selected DSM resources, a program converts the resource attributes and quantities into a data format suitable for direct import into the Planning and Risk model.

Class 3 DSM Capacity Supply Curves

This DSM resource type consists of 50 distinct supply curves, reflecting a combination of products, states, and load areas. The Class 3 DSM programs modeled include the following:

- Residential time-of-use rates (Res RTP)
- Residential critical peak pricing (CPP)
- Commercial and industrial critical peak pricing (C&I CPP)
- Commercial and industrial real-time pricing (C&I RTP)
- Commercial and industrial demand buyback (C&I DBB)

In providing the data for the construction of Class 3 DSM supply curves, the Company did not net-out one product's resource potential against a competing product. As Class 3 DSM resource selections are not included as base resources for planning purposes, not taking product interactions into consideration poised no risk of over-reliance (or double counting the potential) of these resources in the final resource plan. For instance, in the development of the supply curves for residential time-of-use the program's market potential was not adjusted by the market potential or quantity available of a lesser-cost alternative, residential critical peak pricing.

Market potentials and costs for each of the five Class 3 DSM programs modeled were taken from the estimates provided in the DSM potential study and evaluated independently as if it were the only resource available targeting a particular customer segment.

Product price differences between west and east control areas were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in which it is offered regardless of quantify available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year for that product.

Tables 6.17 and 6.18 show the summary level Class 3 DSM program information, by control area, used in the development of the Class 3 resources supply curves. As previously noted, each of the products were further broken down by quantify available by state and load bubble in order to provide the model with location specific information.

Table 6.17 – Class 3 DSM Program Attributes West Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential TOU	Yes, with Res CPP and Res A/C DLC	N/A	Year around	8	$173	2009
Residential CPP	Yes, with Res TOU and Res A/C DLC	Summer 40	June 1- Sept. 15	22	$91	2009
Commercial and Industrial CPP	Yes, with C&I RTP, DBB and commercial curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	9	$33	2009
Commercial and Industrial RTP	Yes, with C&I CPP, DBB and C&I curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	1	$8	2009
Commercial and Industrial DBB	Yes, with C&I CPP and RTP and C&I curtailment	Summer and winter 25, 50 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	10	$18	2009

[1] These costs are before a credit of $23/kW-year is applied for avoided transmission and distribution investment costs.

Table 6.18 – Class 3 DSM Program Attributes East Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential TOU	Yes, with Res CPP and Res A/C DLC	N/A	Year around	11	$166	2009
Residential CPP	Yes, with Res TOU and Res A/C DLC	Summer 40	June 1- Sept. 15	30	$88	2009
Commercial and Industrial CPP	Yes, with C&I RTP, DBB and commercial curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	61	$12	2009
Commercial and Industrial RTP	Yes, with C&I CPP, DBB and C&I curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	14	$6	2009
Commercial and Industrial DBB	Yes, with C&I CPP and RTP and C&I curtailment	Summer and winter 25, 50 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	27	$18	2009

[1] These costs are before a credit of $23/kW-year is applied for avoided transmission and distribution investment costs.

System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs. The data export program converts the Class 3 DSM programs selected by the model into a data format for import into the Planning and Risk model.

Class 2 DSM, Capacity Supply Curves

The 2008 IRP represents the first time the Company has utilized the supply curve methodology in the evaluation and selection of Class 2 DSM energy products. The DSM potential study provided the information to fully assess the contribution of Class 2 DSM resources over IRP planning horizons. Class 2 DSM resource data was provided by state down to the individual measure and facility levels; e.g., specific appliances, motors, air compressors for residential buildings, small offices, etc. In all, the DSM potential study provided Class 2 DSM resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming
- **Measure:**
  - Sixty-two residential measures
  - Seventy-eight commercial measures
  - Thirteen industrial measures
  - Three irrigation measures
- **Facility type:**
  - Six residential facility types
  - Twenty four commercial facility types
  - Twenty eight industrial facility types
  - Two irrigation facility types

The DSM potential study also provided total resource costs, which included both measure cost and a 15 percent adder for administrative costs levelized over measure life at PacifiCorp's cost of capital, consistent with the treatment of supply-side resource costs.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 9.9 million MWh. The technical potential represents the total universe of possible savings before adjustments for what is cost-effective to pursue (economic), likely to be realized (achievable), and impacts of emerging codes and standards such as the 2007 Energy Policy Act, whose impact full wasn't known at the time the DSM potential study was completed.

Despite the granularity of Class 2 DSM resource information available, it was impractical to use this much information in the development of Class 2 DSM resource supply curves. The combination of measures by facility type and state resulted in 12,500 distinct measures that could be modeled using the supply curve methodology.[32] This many supply curves is impossible to handle with PacifiCorp's IRP models. To reduce the resource options for consideration, while not losing the overall resource quantity available, the decision was made to consolidate like meas-

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[32] Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

ures (by weighted-average load shapes and lives) and costs of sets of measures into bundles to reduce the number of combinations to a more manageable number.

The bundles were developed based on Class 2 DSM potential study technical potentials (all economic screens were removed). The achievable assumption was adjusted from that estimated in the DSM potential study to eighty-five percent of the technical potential to account for the practical limits on acquiring all resources in all years. The assumption is consistent with regional planning assumptions in the Northwest. Five cost bundles, across five states, over twenty years equates to 500 supply curves before allocating across the Company load areas shown in Table 6.19.

Table 6.19 – Load Area Energy Distribution by State

State	Goshen	Utah	Walla Walla	West Main	Wyoming	Yakima
CA				100%		
OR			4%	96%		
ID	42%	58%				
UT		100%				
WA			25%			75%
WY		18%			82%	

After the load areas are accounted for (with some states served in more than one load area as noted in table 6.20), the number of supply curves grew to 800, excluding Oregon.

Table 6.20 shows the Class 2 DSM cost bundles used in the 2008 IRP and the associated bundle price. The bundle price can be interpreted as the marginal levelized cost for the group of measures. These prices, adjusted for the $23/kW-year transmission/distribution investment deferral benefit, represent the Class 2 DSM price inputs for the IRP models.

Table 6.20 – Class 2 DSM Cost Bundles and Bundle Prices

Class 2 DSM Cost Bundle	Resource Cost Range	Bundle Price ($/MWh)
Cost Bundle 1	$0.01/kWh to $0.07/kWh	$70
Cost Bundle 2	$0.07/kWh to $0.09/kWh	$90
Cost Bundle 3	$0.09/kWh to $0.11/kWh	$110
Cost Bundle 4	$0.11/kWh to $0.13/kWh	$130
Cost Bundle 5	$0.13/kWh to $0.15/kWh	$150
Cost Bundle 6	$0.15/kWh to $0.18/kWh	$180

Class 2 DSM resources in Oregon are acquired on behalf of the Company through Energy Trust of Oregon programs. To avoid duplicative potential assessment efforts the scope of PacifiCorp's DSM potential study excluded the analysis and evaluation of Class 2 resource potentials in Oregon. As a result, the Company relied on resource potential information provided by the Energy Trust of Oregon. The ETO economically screened their Oregon Class 2 DSM supply curves by using values compiled from regional and utility-specific valuation data.

The ETO provided the Company one cost bundle, weighted and shaped by the end-use measure potential for each year over a twenty-year horizon. Allocating these resources over two load areas in Oregon for consistency with other modeling efforts generated an additional 40 Class 2 supply curves (one cost bundle multiplied by two load areas multiplied by twenty years).

Table 6.21 shows the peak megawatt capacity represented by the supply curves for each state.

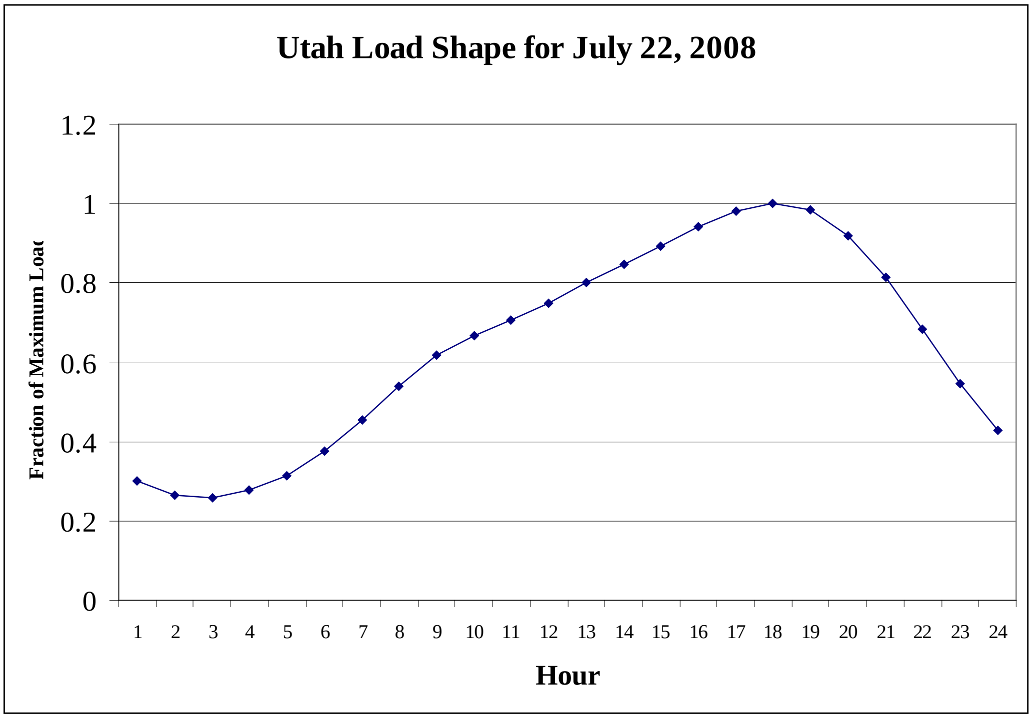
Table 6.21 – Class 2 DSM Supply Curve Capacities by State

State	Capacity (MW)
California	47
Idaho	143
Oregon	472
Utah	1,718
Washington	255
Wyoming	290
Total	2,916

In addition to the program attributes described for the Class 1 and 3 DSM resources, the Class 2 DSM supply curves also have load shapes describing the available energy savings on an hourly basis. For System Optimizer, each supply curve is associated with an annual hourly (“8760”) load shape configured to the 2008 calendar year. These load shapes are used by the model for each simulation year. In contrast, the Planning and Risk model requires for each supply curve a load shape that covers all 20 years of the simulation.

The load shape is composed of fractional values that represent each hour’s demand divided by the maximum demand in any hour for that shape. For example, the hour with maximum demand would have a value of 1.00 (100%), while an hour with half the maximum demand would have a value of 0.50 (50%). Summing the fractional values for all of the hours, and then multiplying this result by peak-hour demand, produces the annual energy savings represented by the supply curve. Figure 6.2 shows the Utah load shape for a representative day: July 22, 2008.

Figure 6.2 – Utah Load Shape



TRANSMISSION RESOURCES

While the Energy Gateway Transmission project was treated as part of the base topology for the IRP models, PacifiCorp included three transmission options that the System Optimizer could select. These options were recommended by PacifiCorp's Transmission Department as additional potential investments to supplement the Gateway project. The first option was an incremental addition to the Energy Gateway West project. This expansion option consisted of a 750 MW capacity increase from Path C in Idaho/northern Utah to the West Main load area, representing Oregon and northern California. This option was available beginning in 2015. The other two options, not associated with the Energy Gateway project, consisted of incremental 200 MW and 400 MW capacities for a Walla Walla to West Main transmission project available beginning in 2014.

MARKET PURCHASES

Resource Option Selection Criteria

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions. Table 6.22 shows the front office transaction resources included in the IRP models. Note that the Table distinguishes FOT resource assumptions made in February 2009 to support additional portfolio analysis based on termination of the 2012 Lake Side II CCCT construction contract. East-side FOT assumption changes were prompted by additional transmission availability from Mona to Utah for which the Company recently became aware.

Table 6.22 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub or Load Area	Product Type	Maximum Available Capacity (MW)	Availability
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	400	2009-2028
California Oregon Border (COB)	3rd Quarter Heavy Load Hour or Flat Annual	400	2009-2028
West Main	3rd Quarter Heavy Load Hour	50	2009-2028
Mead	3rd Quarter Heavy Load Hour	600	2017-2028
Mona	3rd Quarter Heavy Load Hour	200	2009-2028
Utah	3rd Quarter Heavy Load Hour	50	2009-2028
Modifications to Support 2012 Gas Resource Deferral Strategy			
Nevada Utah Border (NUB)	3rd Quarter Heavy Load Hour	164 1/	2012
Nevada Utah Border (NUB)	3rd Quarter Heavy Load Hour	579 2/	2013
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	400	2009-2012
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	775 (400 + 375 with 10% price premium)	2012-2013
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	400	2014-2028

1/ Supported by completion of reactive compensation installation at Camp Williams substation in Utah, and anticipated 300 MW of additional firm transmission from Mead to NUB provided by Nevada Power.

2/ Supported by completion of the Mona to Oquirrh transmission line by the end of 2012, and anticipated 300 MW of additional firm transmission from Mead to NUB provided by Nevada Power.

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

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

The temporary increase in Mid-Columbia FOT market depth, from 400 MW to 775 MW in both 2012 and 2013, is accompanied by an assumed 10 percent price premium.

PacifiCorp examined the recent Mid-Columbia transaction history for forward third-quarter heavy load hour (HLH) products to support this short-term increase.[33] For example, according to the Intercontinental Exchange (ICE), 2008 transaction volumes reached 3,725 MW for third-quarter HLH products delivered in 2009.

Resource Options and Attributes

Two front office transaction types were included for portfolio analysis: an annual flat product, and a HLH 3rd quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, 6 days per week from July through September. Because these products are assumed to be firm for this IRP, the capacity contribution of front office transactions is grossed up for purposes of meeting the planning reserve margin. For example, a 100 MW front office transaction is treated as a 112 MW contribution to meeting PacifiCorp's load obligation plus a 12 percent planning reserve margin, with the selling counterparty holding the reserves necessary to make the product firm.

Prices for front office transaction purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[34] In formulating market purchase options for the IRP models, the Company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the 2008 All-Source RFP, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP.

Resource Description

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

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[33] HLH is the daily time block, hour-ending 7 am – 10 pm, for Monday through Saturday, excluding NERC-observed holidays.

[34] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.

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

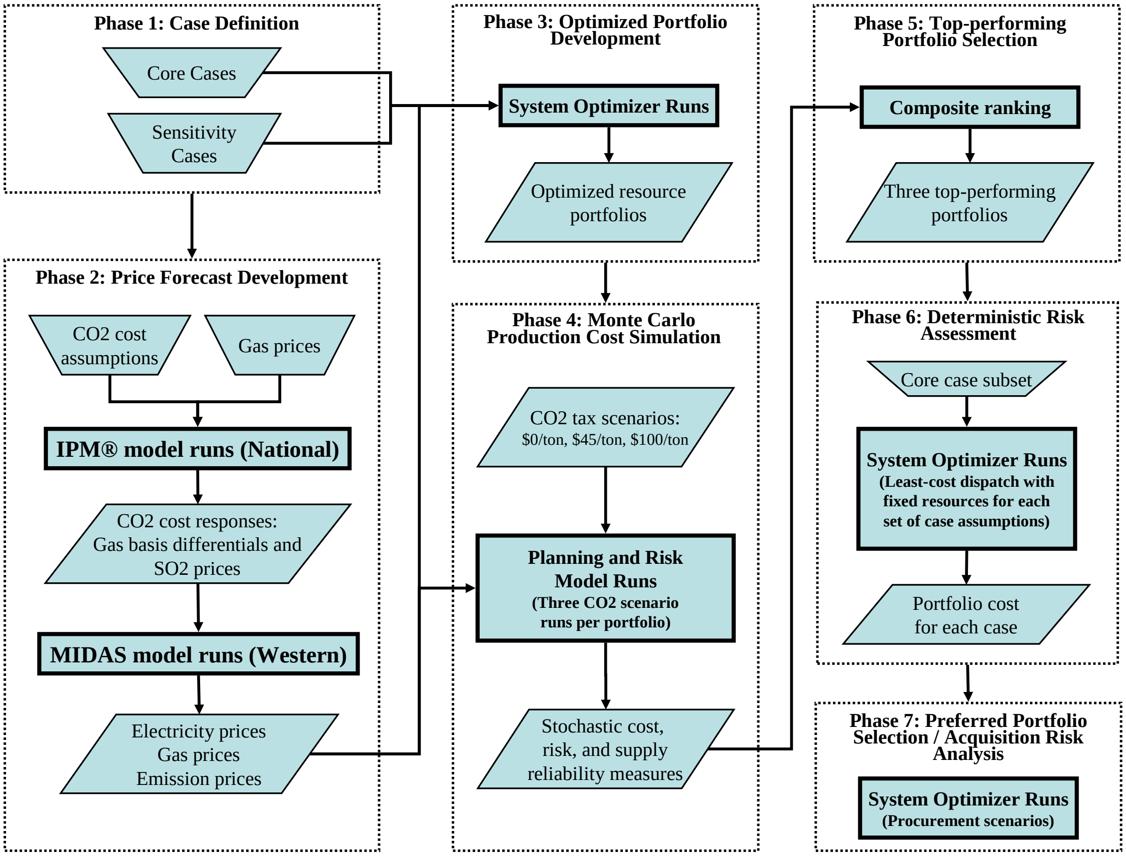
7. MODELING AND PORTFOLIO EVALUATION APPROACH

INTRODUCTION

The IRP modeling effort seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported portfolio performance evaluation. The information drawn from this process, summarized in Chapter 8, was used to help determine PacifiCorp's preferred portfolio and support the analysis of near-term resource acquisition risks.

The 2008 IRP modeling effort consists of seven phases: (1) define input scenarios—referred to as *cases*—characterized by alternative carbon dioxide costs, commodity gas prices, wholesale electricity prices, load growth trends, and other cost drivers, (2) case-specific price forecast development, (3) optimized portfolio development for each case using PacifiCorp's System Optimizer capacity expansion model, (4) Monte Carlo production cost simulation of each optimized portfolio to support stochastic risk analysis, (5) selection of top-performing portfolios using a composite ranking scheme that incorporates stochastic portfolio cost and risk assessment measures, (6) deterministic risk analysis using the System Optimizer, and (7) preferred portfolio selection, followed by acquisition risk analysis of preferred portfolio resources. Figure 7.1 presents the seven phases in flow chart form, showing the main process steps, data flows, and models involved for each phase. General modeling assumptions and price inputs are covered first in this chapter, followed by a profile of each modeling phase.

Figure 7.1 – Modeling and Risk Analysis Process



GENERAL ASSUMPTIONS AND PRICE INPUTS

Study Period and Date Conventions

PacifiCorp executes its IRP models for a 20-year period beginning January 1, 2009 and ending December 31, 2028. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year. The System Optimizer model requires in-service dates designated as the first day of a given month, while the Planning and Risk production cost simulation model allows any date.

Escalation Rates and Other Financial Parameters

Inflation Rates

Integrated resource planning model simulations and price forecasts reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. For the System Optimizer model, a single escalation rate value is used. This value, 1.9 percent, is estimated as the average of the annual corporate inflation rates for the period 2009 to 2030, using PacifiCorp's June 2008 inflation curve. For the Planning and Risk model, the full series of annual values from 2009 through 2028 is used.

Discount Factor

The rate used for discounting in financial calculations is PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2008 IRP is 7.4 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[35]

Federal and State Renewable Resource Tax Incentives

In October 2008, the U.S. Congress provided a one-year extension of the renewable Production Tax Credit (PTC) through December 31, 2009. In February 2009, Congress granted another extension through December 31, 2012. The current tax credit of $21/MWh, which applies to the first 10 years of commercial operation, is converted to a levelized net present value and added to the resource capital cost for entry into the System Optimizer model. The renewable PTC, or an equivalent federal financial incentive, is assumed to be available for all years in the study period.

The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) allows utilities to claim the 30-percent investment tax credit for solar facilities placed in service by January 1, 2017. This tax credit is factored into the capital cost for solar resource options in the System Optimizer model.

A number of state incentive programs are also included into the renewable resource capital costs for eligible facilities. These programs include the following

- **Utah** – The current production tax credit for wind, geothermal, and solar facilities located in Utah is $3.5/MWh over 4 years. There is no sunset provision for this tax credit.

- **Oregon** – Oregon's Business Energy Tax Credit (BETC) provides for an investment tax credit of 50 percent of qualifying costs for projects sited in Oregon up to $20 million for a total credit of $10 million. Projects receive up to $2 million per year over 5 years. Qualifying

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[35] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

projects include wind, solar, hydro, geothermal, and biomass. Projects are on a first come first served basis up to the Oregon's annual allocated dollars of tax benefits. There is no sunset provision for this credit, but the cap is likely to change from time to time.

- **Idaho** – 3% Investment Tax Credit (ITC) provision on tangible personal property. Credit is available to all construction projects and not unique to renewable projects.

Asset Lives

Table 7.1 lists the generation resource asset book lives assumed for levelized fixed charge calculations.

Table 7.1 – Resource Book Lives

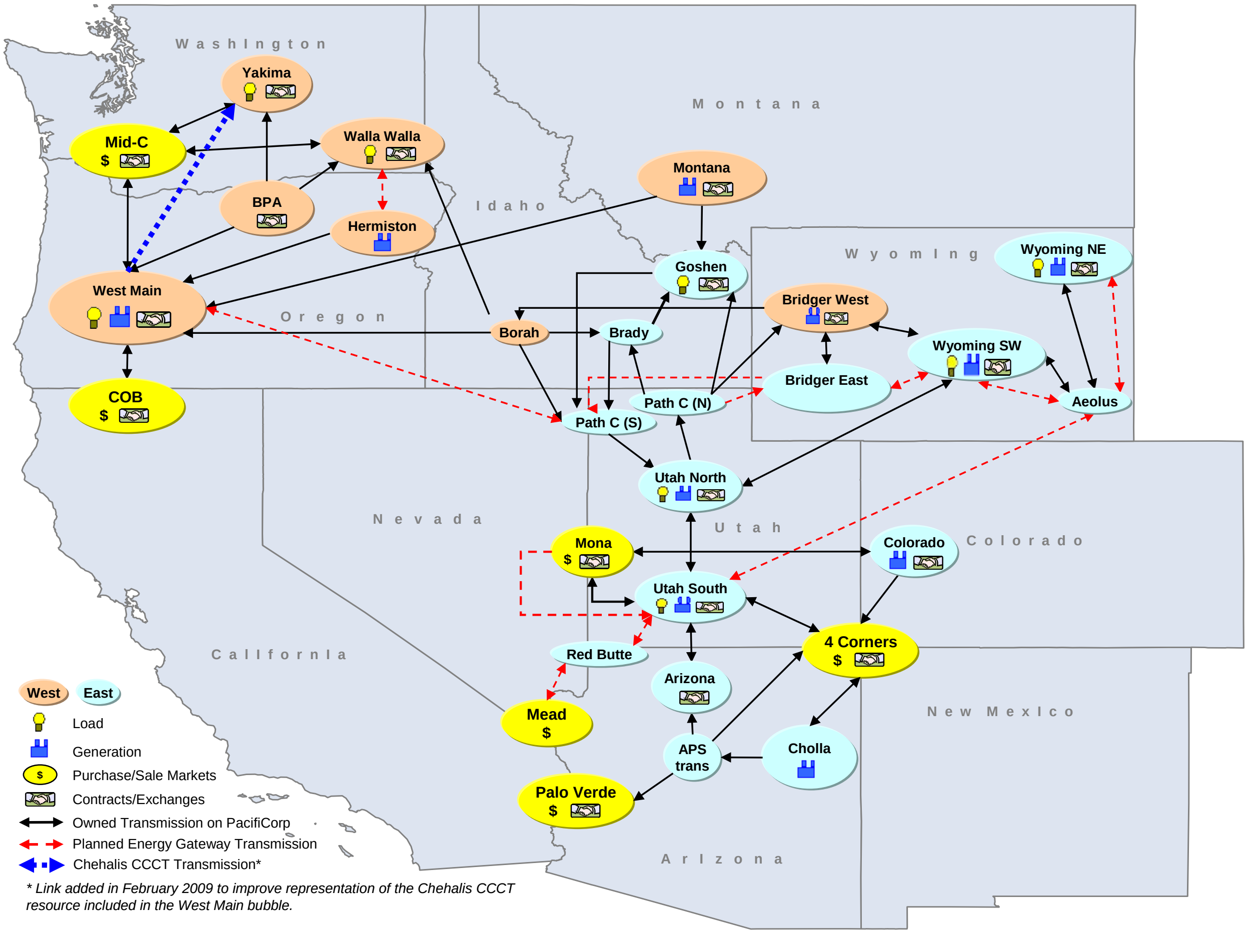
Resource	Book Life (Years)
Supercritical pulverized coal/Integrated Gasification Combined-Cycle	40
Coal plant retrofit with carbon capture and sequestration	20
Combined Cycle Combustion Turbine	40
Pumped Storage	50
Simple Cycle Combustion Turbine (SCCT) Frame	35
Geothermal	40
Solar Photovoltaic	20
Solar Thermal	30
Compressed Air Energy Storage	30
Single Cycle Combustion Turbine (SCCT) Frame	30
Intercooled Aeroderivative SCCT	30
Internal Combustion Engine	30
Fuel Cells	25
Utility-Scale Combined Heat & Power (CHP)	25
Wind	25
Battery Storage	30
Biomass	30
Hydrokinetic, Wave - Floating Buoy	20
Nuclear Plant	40
CHP-Reciprocating Engine	20
CHP - Gas Turbine	20
CHP - Microturbine	15
CHP - Fuel Cell	10
CHP - Commercial Biomass, Anaerobic Digester	15
CHP - Industrial Biomass Waste	15
Solar - Rooftop Photovoltaic	25
Solar - Water Heaters	15
Solar - Attic Fans	10
Dispatchable Standby Generators	20
Recovered Energy Generation	30
Microturbine	15

Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its Eastern Control Area and 10 bubbles in its Western Control Area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant function’s current firm rights on the transmission lines. This topology is defined for both the System Optimizer and Planning and Risk models, and was also used for IRP modeling support for PacifiCorp’s 2009 business plan.

Figure 7.2 shows the IRP transmission system model topology. Segments of the planned Energy Gateway Transmission Project are indicated with red dashed lines.

Figure 7.2 – Transmission System Model Topology



** Link added in February 2009 to improve representation of the Chehalis CCCT resource included in the West Main bubble.*

The most significant change to the model topology from the one used for the 2007 IRP Update is the expansion of the single Wyoming bubble into three bubbles: Wyoming Southwest, Wyoming Northeast, and Aeolus (substation). This disaggregation supports a more refined view of potential Wyoming resource siting in consideration of transmission constraints—represented as the TOT 4A cut plane—as well as the addition of the planned Aeolus substation that supports Energy Gateway Transmission expansion.

The other major change to the model topology is the addition of the Hermiston bubble in the Western Control Area, which supports the representation of the Walla Walla to McNary segment of the Gateway project.

In February 2009, additional changes were made to the system topology to improve representation of long-term transmission rights for the Chehalis, Washington combined-cycle plant included in the West Main bubble. One of the changes involved the addition of a uni-directional path from the West Main to Yakima bubble. This path addition is shown as a blue dashed line in Figure 7.2. Additionally, the Energy Gateway segment C path (uni-directional, Mona to Oquirrh) was added to facilitate additional market transfer capability from the Mona bubble to Utah South.

CASE DEFINITION

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations in inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values to ensure that a reasonably wide range in potential outcomes is captured.

PacifiCorp defined two types of cases: core cases and sensitivity cases. Core cases focus on broad comparability of portfolio performance results for three key variables. These variables include (1) the level of a per-ton carbon dioxide tax, (2) natural gas and wholesale electricity prices based on PacifiCorp’s forward price curves and adjusted as necessary to reflect CO_2 tax impacts, and (3) retail load growth. The Company developed 29 core cases based on a combination of input variable levels.

In contrast, sensitivity cases focus on changes to resource-specific assumptions, alternative CO_2/renewable energy regulatory policies, and planning assumptions. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 17 sensitivity cases reflecting alternative CO_2 compliance strategies, clean base load technology availability, an alternative planning reserve margin level, and inclusion of price-responsive demand-side management programs (Class 3 DSM) as resource options. Also included in the sensitivity case group are two “reference” cases reflecting the 2009 business plan resources for 2009 through 2018, resulting in a total of 19 sensitivity cases.

In developing these cases, PacifiCorp kept to a target range in terms of the total number (40 to 50) in light of the data processing and model run-time requirements involved. To keep the number of cases within this range, PacifiCorp excluded some core cases with improbable combinations of certain input levels, such as a $100 CO_2 tax and high load growth. (With a high CO_2 tax, a significant amount of demand reduction is expected to occur in the form of conservation, energy efficiency improvements, and utility load control programs.)

PacifiCorp also relied heavily on feedback from public stakeholders. The Company assembled and refined an initial set of cases during April through June 2008, and held three public meetings during May and June to solicit recommendations on their design. The focus of comments was on the number of cases that should be modeled and the appropriateness of the CO_2 tax levels selected. Additional case modifications took place from July through November, reflecting additional stakeholder feedback and input assumption updates made to support the 2009 business plan. For example, PacifiCorp augmented the cases defined with the June 2008 forward price curves as the base forecast with additional ones that used the October price curves. This expansion of cases reflected the desire to account in the IRP analysis the rapid and large price decreases experienced during the last half of 2008.

Case Specifications

Tables 7.2 and 7.3 profile the core and sensitivity/business plan case specifications, respectively. Descriptions of the case variables and explanatory remarks on specific cases follow the tables.

Table 7.2 – Core Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Core Cases										
1	CO2 tax	$0	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
2	CO2 tax	$0	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
3	CO2 tax	$0	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
4	CO2 tax	$45	Low	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
5	CO2 tax	$45	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
6	CO2 tax	$45	Low	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
7	CO2 tax	$45	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
8	CO2 tax	$45	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
9	CO2 tax	$45	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
10	CO2 tax	$45	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
11	CO2 tax	$45	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
12	CO2 tax	$45	Medium	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
13	CO2 tax	$45	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
14	CO2 tax	$45	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
15	CO2 tax	$45	High	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
16	CO2 tax	$70	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
17	CO2 tax	$70	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
18	CO2 tax	$70	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
19	CO2 tax	$70	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
20	CO2 tax	$70	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
21	CO2 tax	$70	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
22	CO2 tax	$70	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
23	CO2 tax	$100	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
24	CO2 tax	$100	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
25	CO2 tax	$100	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
26	CO2 tax	$100	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
27	CO2 tax	$100	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
28	CO2 tax	$100	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
29	CO2 tax	$100	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded

Table 7.3 – Sensitivity and Business Plan Reference Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Real CO2 Cost Escalation with Changing Load Growth										
30	CO2 tax	$45 (2013) to $163 (2028)	Medium	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
31	CO2 tax	$45 (2013) to $163 (2028)	High	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
National CO2 Cap-and-Trade Policy: Lieberman-Warner "Climate Security Act of 2008" (SB 3036, introduced May 20, 2008)										
32	Cap-and-Trade	Market	Medium	Oct-08	Medium	Base	Base	Base	12%	Excluded
High-Cost Outcome										
33	CO2 tax	$100	High	Jun-08	High	Base	Late	High	12%	Excluded
Clean Base-Load Generation Availability										
34	CO2 tax	$45	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
35	CO2 tax	$45	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
36	CO2 tax	$70	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
37	CO2 tax	$70	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
High Plant Construction Costs										
38	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	High	12%	Excluded
39	CO2 tax	$45	High	Jun-08	Medium	Base	Base	High	12%	Excluded
Oregon CO2 Reduction Targets (from HB 3543) Applied as System-wide Hard Caps										
40	Hard Cap	N/A	Medium	Jun-08	Medium	Base	Base	Base	12%	Excluded
Alternative Planning Reserve Margin Level (15%)										
41	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
42	CO2 tax	$70	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
43	CO2 tax	$100	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
Alternative renewable policy assumptions										
44	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	High	Base	Base	12%	Excluded
45	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Base/PTC expires	Base	Base	12%	Excluded
Business Plan Reference Cases										
46	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Fixed RPS-compliant wind schedule	Base	Base	12%	Excluded
47	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Optimized RPS-compliant renewables	Base	Base	12%	Excluded
Class 3 DSM For Peak Load Reduction										
48	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	12%	Included

Carbon Dioxide Compliance Strategy and Costs

Given that no single CO_2 reduction compliance approach has emerged as a consistent front-runner for adoption, the long-term planning effort undertaken through this IRP considers a wide range of carbon cost outcomes that are assessed as a direct tax on emissions (each short ton of CO_2 emitted). As mentioned above, a CO_2 tax is modeled for all the core cases. The CO_2 tax has an assumed 2013 implementation date, and increases at PacifiCorp's assumed inflation rate.

The tax is treated as a variable cost in both the System Optimizer and PaR models. In System Optimizer, the tax is accounted for in both resource investment decisions as well as the model dispatch solution. For the PaR model, the tax is accounted for in the model's unit commitment/dispatch solution.

The core cases have been specified with four tax levels: no tax, \$45/ton, \$70/ton, and \$100/ton. The \$0 tax serves to create reference portfolios from which the incremental cost of CO_2 regulations can be determined. The \$45 tax represents a reasonable intermediate value and starting point at which significant changes in resource mix over the long term can be expected to occur. This value—along with the \$70 value—are also in line with the Electric Power Research Institute's finding that for its reference CO_2 price impact modeling case for western electricity markets, "...it takes a CO_2 price of roughly \$50/ton to flatten the growth of emissions over time, and closer to \$70/ton to effect a significant reduction over time."[36] The \$100 tax then reflects a reasonable high-end value associated with an aggressive Federal emission reduction policy.

For sensitivity cases 30 and 31, PacifiCorp developed a CO_2 tax trajectory with a real cost escalation, and also assumed that the associated demand response would result in a lower load growth trend beginning in 2021. The CO_2 tax values for these cases are shown in Table 7.4.

Table 7.4 – CO_2 Tax Values

Year	CO2 Tax Level, 2008 Dollars per Ton			
	$45	$70	$100	$45, Real Escalation
2013	49.44	$76.91	$109.87	45.00
2014	50.33	$78.29	$111.84	52.86
2015	51.29	$79.78	$113.97	60.71
2016	52.31	$81.37	$116.25	68.57
2017	53.36	$83.00	$118.57	76.43
2018	54.43	$84.66	$120.95	84.29
2019	55.51	$86.36	$123.36	92.14
2020	56.62	$88.08	$125.83	100.00
2021	57.70	$89.76	$128.22	107.86
2022	58.80	$91.46	$130.66	115.71
2023	59.91	$93.20	$133.14	123.57
2024	61.05	$94.97	$135.67	131.43
2025	62.15	$96.68	$138.11	139.29
2026	63.27	$98.42	$140.60	147.14
2027	64.47	$100.29	$143.27	155.00
2028	65.70	$102.19	$145.99	162.86

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[36] Electric Power Research Institute, Slide Presentation, Collaborative EPRI Analysis of CO_2 Price Impacts on Western Power Markets, page 18, June 2008.

For sensitivity case 32, The CO_2 costs are in the form of allowance market prices resulting from implementation of a federal cap-and-trade program such as the Lieberman-Warner Climate Security Act of 2008. (This proposed legislation specified a final CO_2 emissions target of 71 percent below 2005 levels in 2050.) Due to the complexity of developing the inputs for this sensitivity case, PacifiCorp did not have time to perform this analysis before this IRP was prepared. PacifiCorp will make the results available to IRP stakeholders once the study has been completed.

Sensitivity case 40 assumes that PacifiCorp is subject to a system-wide hard CO_2 cap. A hard cap is a physical emission limit that cannot be exceeded, and is typically expressed as a declining annual value. This sensitivity case is intended to support the following Public Utility Commission of Oregon's 2007 IRP acknowledgment order requirement:

> For the 2007 IRP update and next planning cycle, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.[37]

Oregon's HB 3543 targets are to achieve greenhouse gas emission levels 10 percent below 1990 levels by 2020, and by 2050, achieve reductions of a least 75 percent below 1990 levels. With a 2012 emissions base of 56.1 million tons, these targets translate into 41.4 million tons by 2020 and 33.4 million tons by 2028. Because PacifiCorp plans on a system basis, and its IRP models are not currently capable of representing Oregon-only emission constraints in the context of such system planning, Oregon's hard cap is applied on a system level.

The CO_2 compliance strategy and cost assumptions for sensitivity cases 46 and 47 reflect those used for PacifiCorp's 2009 business plan, which is based on a Federal cap-and-trade compliance mechanism. Cap-and-trade assumptions include the following:

- Emissions peaking in 2012 (56.1 million tons) and declining to 2007 emission levels (56.5 million tons by 2025), assuming straight-line annual decreases for modeling purposes
- Straight-line annual emissions decreasing to 1990 levels by 2030
- An initial CO_2 allowance price of \$8.79/ton starting in 2013 (in 2008 dollars), and increasing at PacifiCorp's annual inflation rates
- No auctioning or banking of allowances

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[37] Public Utility Commission of Oregon, Order No. 08-232, Docket LC 42, April 24, 2008, p. 36.

Table 7.5 – CO_2 Prices for the Business Plan Reference Cases

Year	CO2 Price 2008 Dollars per Ton
2013	8.79
2014	8.95
2015	9.12
2016	9.30
2017	9.49
2018	9.68
2019	9.87
2020	10.07
2021	10.26
2022	10.45
2023	10.65
2024	10.85
2025	11.05
2026	11.25
2027	11.46
2028	11.68

Natural Gas and Electricity Prices

Due to the strong correlation between natural gas and wholesale electricity prices, these variables were linked together as low, medium, or high values for a case. Two sets of gas/electricity price scenario values were used for defining cases. The June 2008 forward price curves served as the initial base forecast for IRP modeling support for the 2009 business plan and development of IRP scenario price curves reflecting CO_2 price responses. Due to the large decline in gas prices following the spring/summer spike, PacifiCorp adopted the October 2008 forward price curves for the final business plan modeling, and incorporated these forecasts as additional cases in the IRP (cases 9, 10, 11, 18, 19, 20, 25, 26, and 27). The price forecasting methodology and resulting scenario price forecasts are presented later in this chapter.

Retail Load Growth

The low and high load growth forecasts reflect a respective one-percentage-point average annual growth rate decrease and increase relative to the growth rate for the medium (1-in-2) forecast. For cases 30 and 31, PacifiCorp combined the medium forecast for 2009 to 2020, and the low forecast for 2021 to 2028, using a smoothing algorithm to determine the data elements around the breakpoint. Figures 7.3 and 7.4 show the annual peak load and energy forecast values used for the case definitions.

Figure 7.3 – Peak Load Growth Scenarios

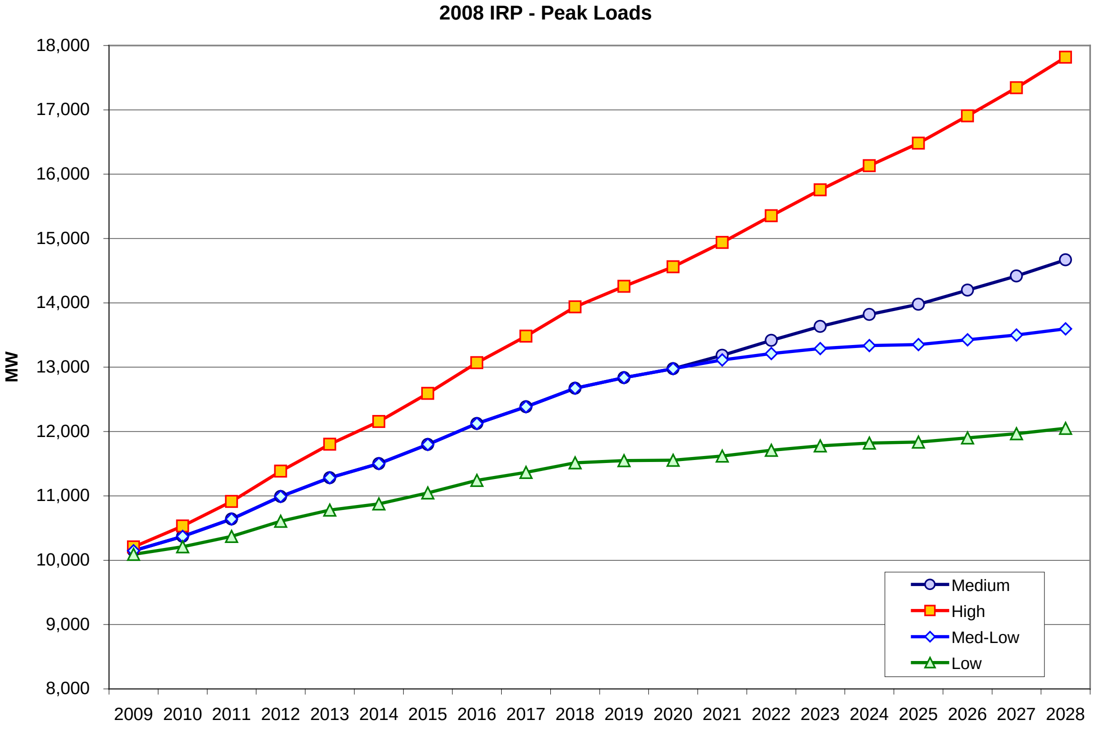
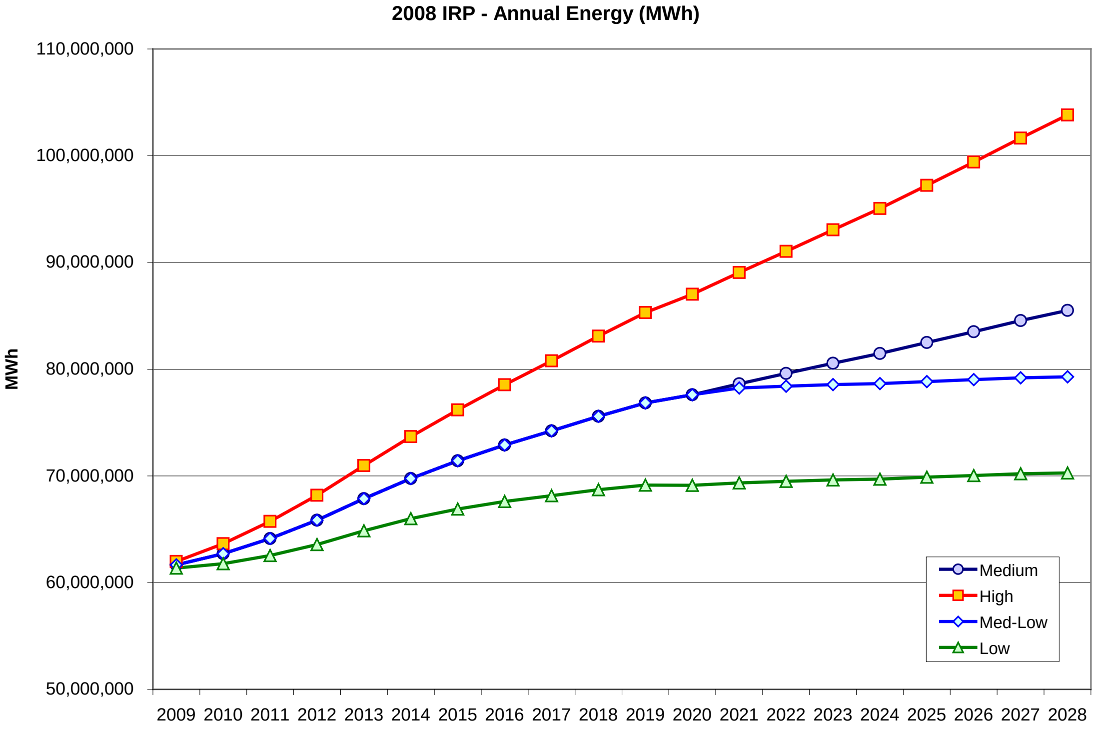


Figure 7.4 – Energy Load Growth Scenarios



Renewable Portfolio Standards

In addition to the base renewable portfolio standards modeled, sensitivity case 44 tests a scenario for which the renewable generation requirement is higher, reflecting imposition of a Federal standard or more aggressive state standards. (Modeling of renewable portfolio standards is discussed in the section on optimized portfolio development.)

For the high RPS generation requirement, PacifiCorp assumed that the current Revised Protocol under the Multi-state Process remains in place, requiring the Company to acquire sufficient system resources to meet Oregon's cost allocation share based on their RPS targets. This assumption translates into a 25-percent RPS generation requirement with respect to the forecasted system load by 2026.

Renewables Production Tax Credit Expiration

Sensitivity case 45 is intended to study how the loss of the PTC affects the timing and magnitude of renewable resource additions. For this sensitivity, the renewables PTC is assumed to fully expire in 2013.

Clean Base Load Plant Availability

Sensitivity cases 34 through 37 evaluate whether clean base load plants—IGCC and new/existing pulverized coal plant retrofits with carbon capture and sequestration—are cost-effective enough to build as early as 2020 given the \$45/ton and \$70/ton CO_2 tax levels and variation in gas prices. The assumed earliest availability for these plants is 2025.

High Plant Construction Costs

Sensitivity cases 38 and 39 are intended to determine the resource selection impact of increasing capital costs for all resources by 20 percent above their base values under medium and high gas price conditions. Capital-intensive resources will be disadvantaged under this assumption, so these sensitivities test the extent that such resources are deferred or eliminated from portfolios despite higher gas prices.

Capacity Planning Reserve Margin

Cases 41 42, and 43 are intended for development of portfolios built to meet or exceed a 15-percent capacity planning reserve margin. The resulting portfolios are compared with their counterpart portfolios built to a 12-percent planning reserve margin (cases 8, 17, and 24). These comparisons are intended to determine the resource mix impact of higher CO2 tax levels.

Business Plan Reference Cases

Cases 46 and 47 represent portfolios that have the major 2009 business plan resources fixed in the model. They were optimized with business plan assumptions, including the \$8/ton cap-and-trade program assumptions and October 2008 price forecasts. System Optimizer was allowed to select DSM and distributed generation resources up to 2018, and allowed to select any resource from 2019 onward subject to the annual quantity constraints outlined in Chapter 6. (Business plan resources only cover the period 2009 through 2018.) The difference between the two cases is that the renewable resources were fixed in case 46 for 2009-2018—reflecting the wind acquisition schedule determined by PacifiCorp's wind development team for the business plan38—whereas for case 47, the model was allowed to optimize the amount and timing of renewables subject to the annual quantity constraints.

Class 3 Demand-side Management Programs for Peak Load Reductions

For sensitivity case 48, System Optimizer is allowed to select price-responsive DSM programs. These programs, outlined in Chapter 6, include real-time pricing (for commercial and industrial customers), demand buyback, curtailment, and critical peak pricing.

SCENARIO PRICE FORECAST DEVELOPMENT

On a central tendency basis, commodity markets tend to respond to the evolution of supply and demand fundamentals over time. Due to a complex web of cross-commodity interactions, price movements in response to supply and demand fundamentals for one commodity can have implications for the supply and demand dynamics and price of other commodities. This interaction routinely occurs in markets common to the electric sector as evidenced by a strong positive correlation between natural gas prices and electricity prices.

Some relationships among commodity prices have a long historical record that have been studied extensively, and consequently, are often forecasted to persist with reasonable confidence. However, robust forecasting techniques are required to capture the effects of secondary or even tertiary conditions that have historically supported such cross-commodity relationships. For example, the strong correlation between natural gas prices and electricity prices is intrinsically tied to the increased use of natural gas-fired capacity to produce electricity. If for some reason in the future natural gas-fired capacity diminishes in favor of an alternative technology, the linkage between gas prices and electricity prices would almost certainly weaken.

PacifiCorp deploys a variety of forecasting tools and methods to capture cross-commodity interactions when projecting prices for those markets most critical to this IRP – natural gas prices, electricity prices, and emission prices. Figure 7.5 depicts a simplified representation of the framework used by PacifiCorp to develop the price forecasts for these different commodities. At the highest level, the commodity price forecast approach begins at a global scale with an assessment of natural gas market fundamentals. This global assessment of the natural gas market yields a price forecast that feeds into a national model where the influence of emission and renewable energy policies is captured. Finally, outcomes from the national model feed into a regional model where the up-stream gas prices and emission prices drive a forecast of wholesale electricity prices. In this fashion, we are able to produce an internally consistent set of price forecasts across a range of potential future outcomes at the pricing points that interface with PacifiCorp's system.

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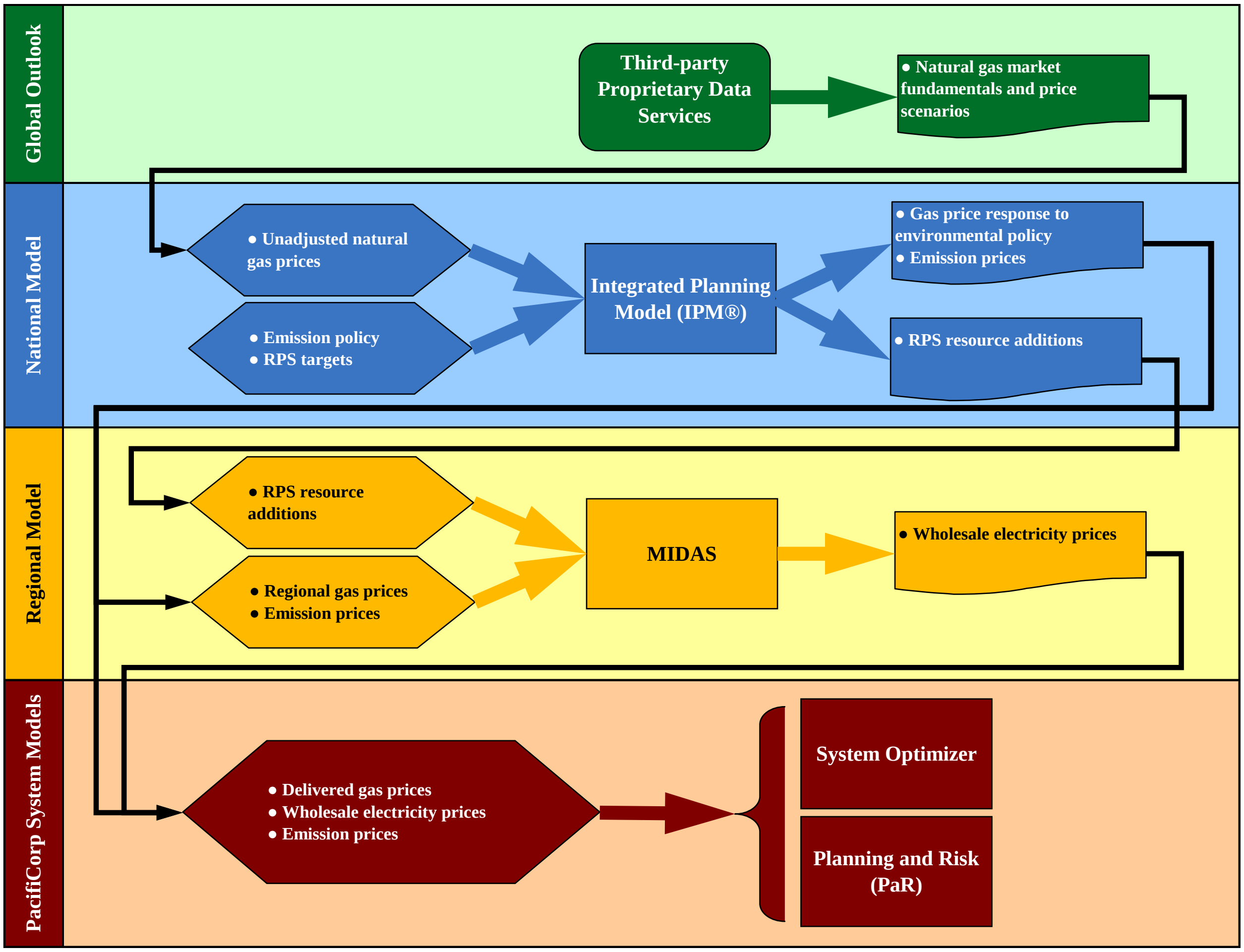
[38] This wind acquisition schedule reflects an assessment of RPS requirements, capital budget impacts, current and prospective commercial opportunities, transmission constraints and expansion considerations (i.e., the Energy Gateway Transmission Project), operational and system integration issues, locational diversity, state procurement rules, and the MEHC renewables acquisition commitment.

Figure 7.5 – Modeling Framework for Commodity Price Forecasts



The process begins with an assessment of global gas market fundamentals and an associated forecast of North American natural gas prices. In this step, PacifiCorp relies upon a number of third-party proprietary data and forecasting services to establish a range of gas price scenarios. Each price scenario reflects a specific view of how the North American natural gas market will balance supply and demand. Given the emergence of liquefied natural gas (LNG) in the global marketplace, the linkage of global gas prices to global oil prices, and the potential need for LNG imports to balance supply with domestic demand, any price forecast for the North American market requires a view of global fundamentals.

Once a natural gas price forecast is established, the integrated planning model (IPM®) is used to simulate the entire North American power system. IPM®, a linear program, determines the least cost means of meeting electric energy and capacity requirements over time, and in its quest to lower costs, ensures that all assumed emission policies and renewable portfolio standard (RPS) policies are met. Concurrently, IPM® can be configured with a dynamic natural gas price supply curve that allows natural gas prices to respond to changes in demand triggered by environmental compliance. Additional outputs from IPM® include a forecast of resource additions consistent with all specified RPS targets, electric energy and capacity prices, coal prices, electric sector fuel consumption, and emission prices for policies administered in a cap-and-trade framework.

Once emission prices and the associated gas price response are forecasted with IPM®, results are used in a regional model named Midas, to produce an accompanying wholesales electricity price forecast. Midas is an hourly chronological dispatch model configured to simulate the Western Interconnection and offers a more refined representation of western wholesale electricity markets than is possible with IPM®. Consequently, we are able to produce a more granular price projection that covers all of the markets required for the PacifiCorp system models used in the IRP. The gas, wholesale electricity, and emission price forecasts developed under this framework and used in the cases for this IRP are summarized in the sections that follow.

Gas and Electricity Price Forecasts

A total of five underlying natural gas price forecasts are used to develop the 28 unique gas price projections for the cases analyzed in this IRP. A range of fundamental assumptions affecting how the North American market will balance supply and demand defines the five underlying price forecasts. Table 7.6 shows representative prices at the Henry Hub benchmark for the five underlying natural gas price forecasts. The five forecasts serve as a point of reference and are adjusted to account for changes in natural gas demand driven by a range of environmental policy and technology assumptions specific to each IRP case.

Table 7.6 – Underlying Henry Hub Price Forecast Summary (nominal $/MMBtu)

Forecast Name	2010	2015	2020	2025	2030
High - June 2008	$18.06	$18.71	$21.21	$23.28	$25.55
High - October 2008	$11.57	$14.68	$19.98	$21.93	$24.07
Medium - June 2008	$11.23	$9.90	$12.31	$13.51	$14.83
Medium - October 2008	$7.83	$8.58	$11.07	$12.85	$14.11
Low - June 2008[39]	$5.83	$6.29	$7.09	$7.78	$8.54

Price Projections Tied to the High June 2008 Forecast

The underlying June 2008 high gas price forecast is defined by high oil prices and low LNG imports, reduced production from mature natural gas fields, disappointments in new production from frontier gas fields, and policies that hold back new coal and nuclear additions, which supports electric sector natural gas demand despite high prices. Figure 7.6 summarizes prices at the Henry Hub benchmark and Figure 7.7 summarizes the accompanying electricity prices for the forecasts developed around the high June 2008 gas price projection.

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[39] This underlying forecast serves as the reference case for development of the “low - October 2008” price forecast scenario.

Figure 7.6 – Henry Hub Natural Gas Prices from the High June 2008 Underlying Forecast

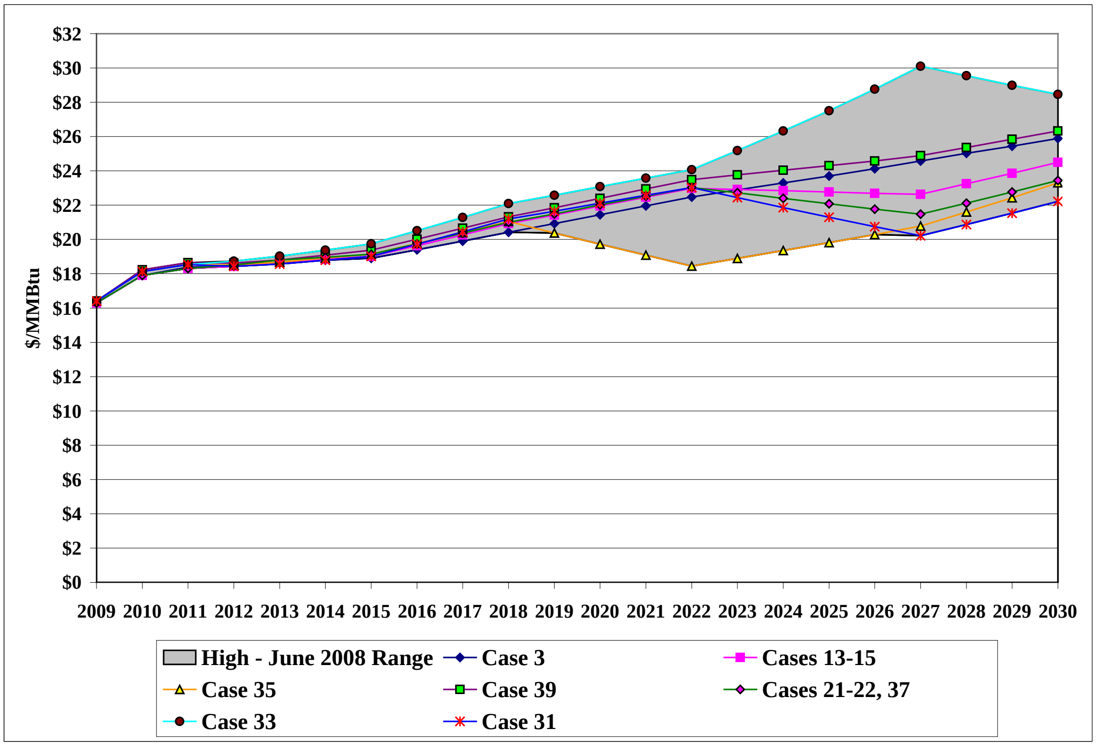
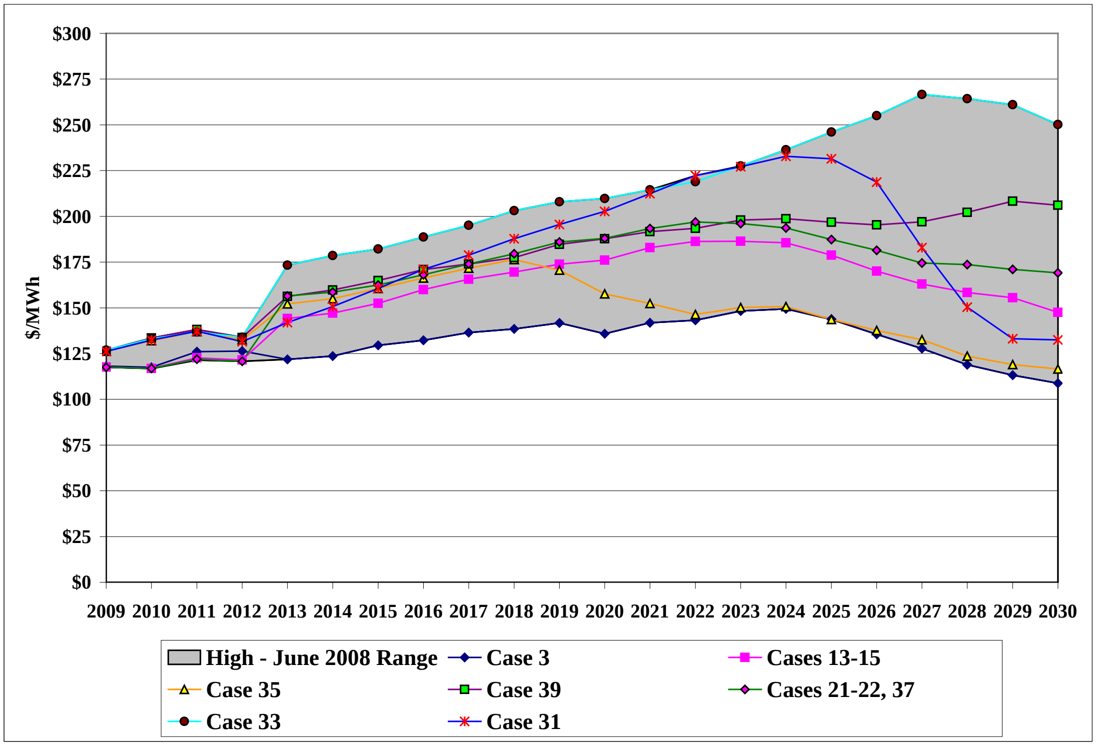


Figure 7.7 – Western Electricity Prices from the High June 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the High October 2008 Forecast

A second high gas price forecast was added in October 2008 in response to economic developments, which lowers the near-term price trajectory in response to lagging demand. Longer-term, the October 2008 high gas price forecast is lower than the June 2008 forecast due to a more optimistic outlook for domestic unconventional natural gas production. Figure 7.8 depicts Henry Hub benchmark prices and Figure 7.9 summarizes the accompanying electricity prices for the forecasts developed around the high October 2008 gas price projection.

Figure 7.8 – Henry Hub Natural Gas Prices from the High October 2008 Underlying Forecast

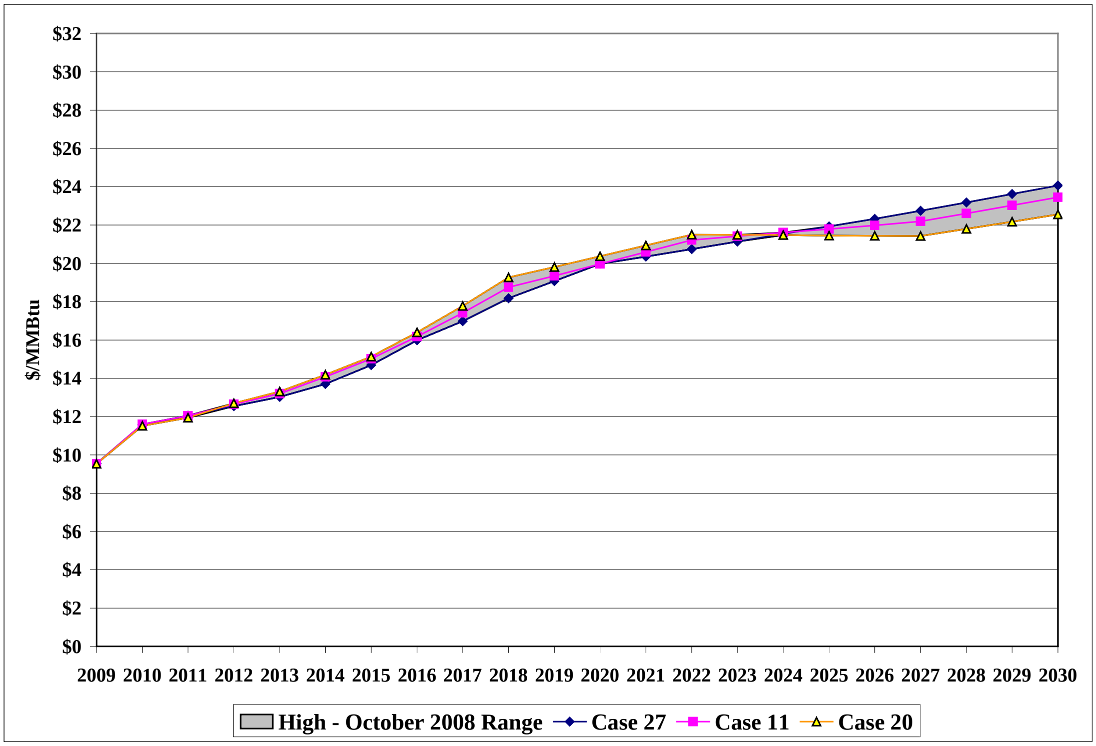
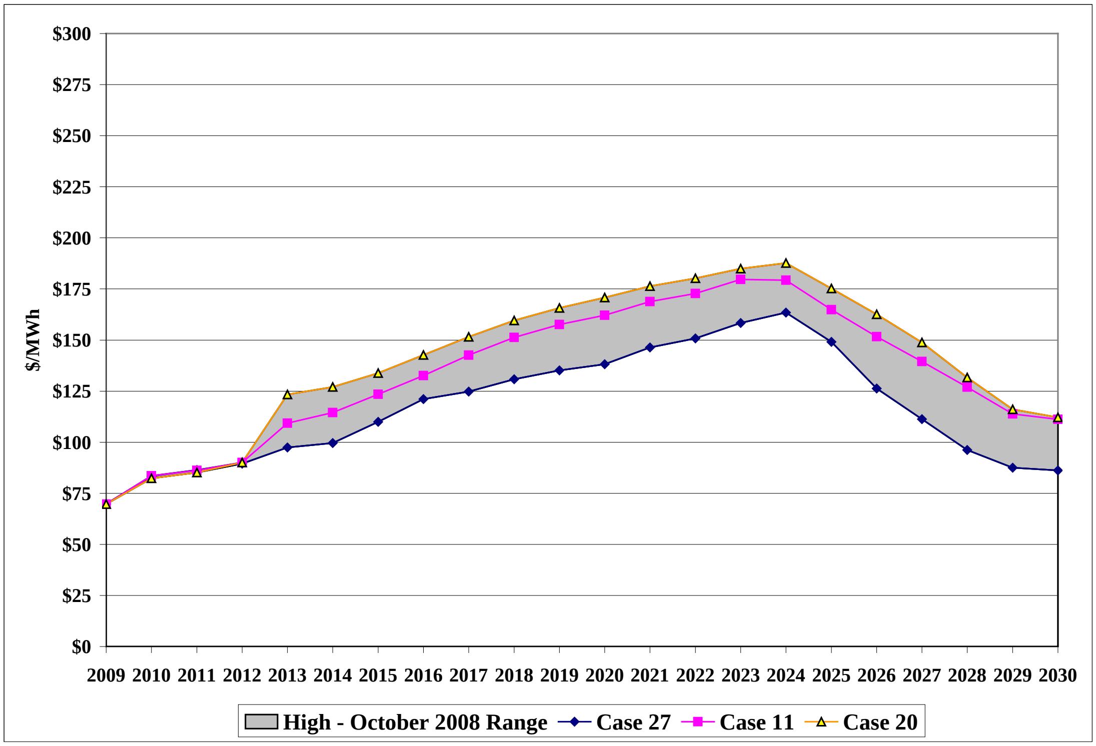


Figure 7.9 – Western Electricity Prices from the High October 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Medium June 2008 Forecast

The underlying June 2008 medium gas price forecast relies upon market forwards for the first six years and a fundamentals-based projection thereafter. For the market portion of the forecast, prices are based upon forwards as of market close on June 30, 2008. The fundamentals-based part of the forecast depicts a future in which declining LNG imports coincide with strong demand from the electric sector driven by resistance to new coal-fired and nuclear capacity. It is assumed that unconventional production will largely be able to keep pace with growing demand, but production costs are projected to be higher than what has been exhibited in the recent expansion of unconventional fields in the Rocky Mountain region and in the Barnett Shale formation. Further, global oil prices are anticipated to remain much higher than historical averages. As with the high price forecasts, a second medium price forecast was added in October 2008 in response to economic developments. Figure 7.10 shows Henry Hub benchmark prices and Figure 7.11 includes the accompanying electricity prices for the forecasts developed around the medium June 2008 gas price projection.

Figure 7.10 – Henry Hub Natural Gas Prices from the Medium June 2008 Underlying Forecast

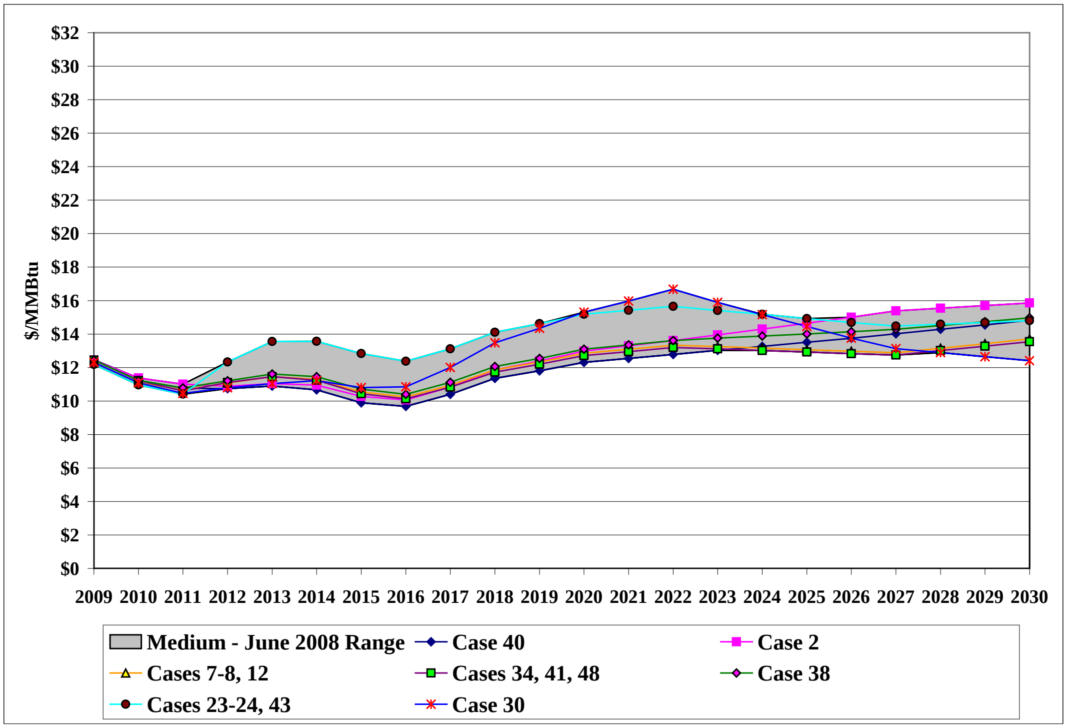
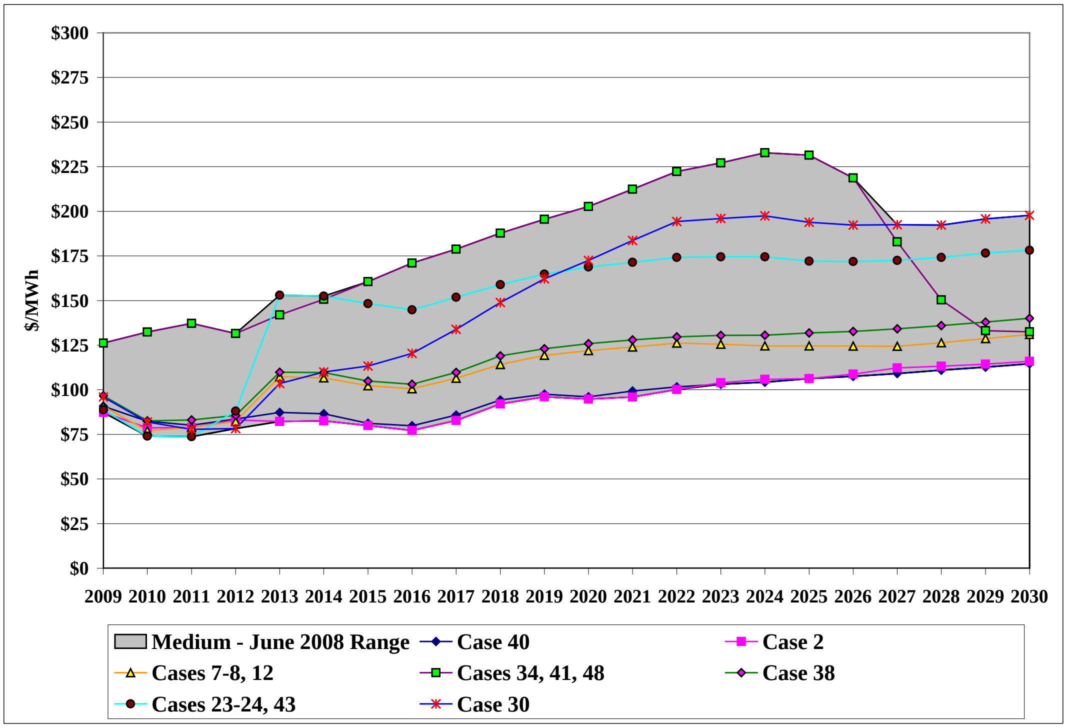


Figure 7.11 – Western Electricity Prices from the Medium June 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Medium October 2008 Forecast

As with the high price forecasts, a second underlying medium gas price forecast was added in October 2008 in response to economic developments. In this second medium price forecast, the market portion of the curve is replaced with forwards as of market close on October 20, 2008. The longer-term forecast is slightly lower than the June 2008 medium forecast, which reflects a lower long-term oil price outlook and a more optimistic view of new supply out of Alaska. Figure 7.12 shows Henry Hub benchmark prices and Figure 7.13 includes the accompanying electricity prices for the forecasts developed around the medium October 2008 gas price projection.

Figure 7.12 – Henry Hub Natural Gas Prices from the Medium October 2008 Underlying Forecast

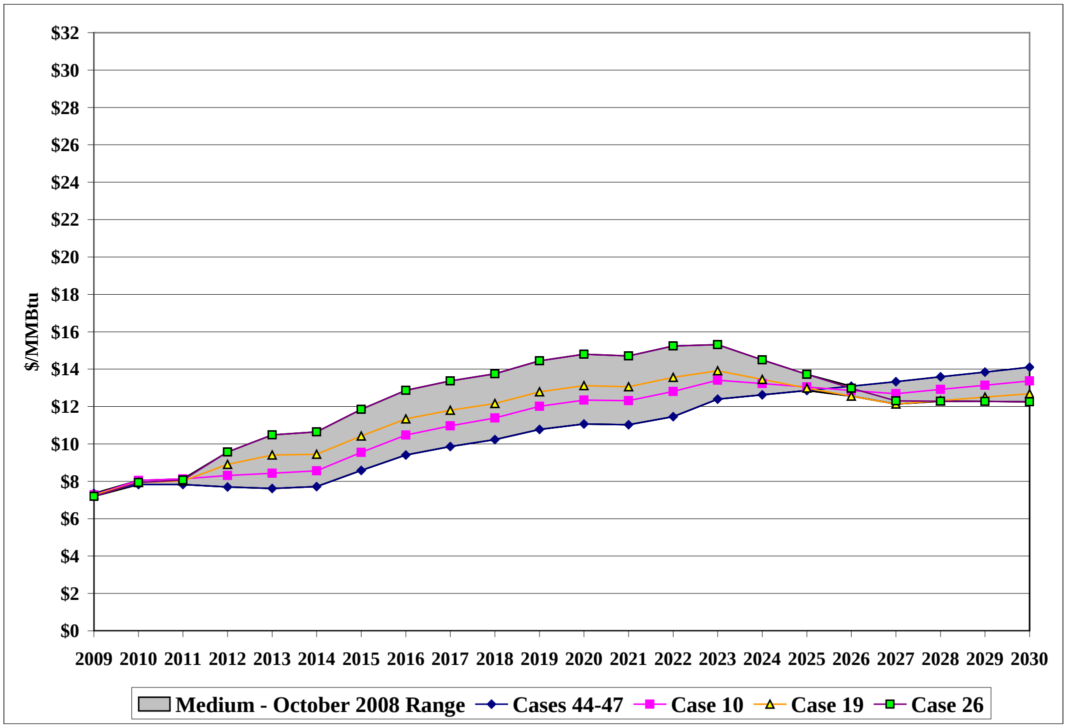
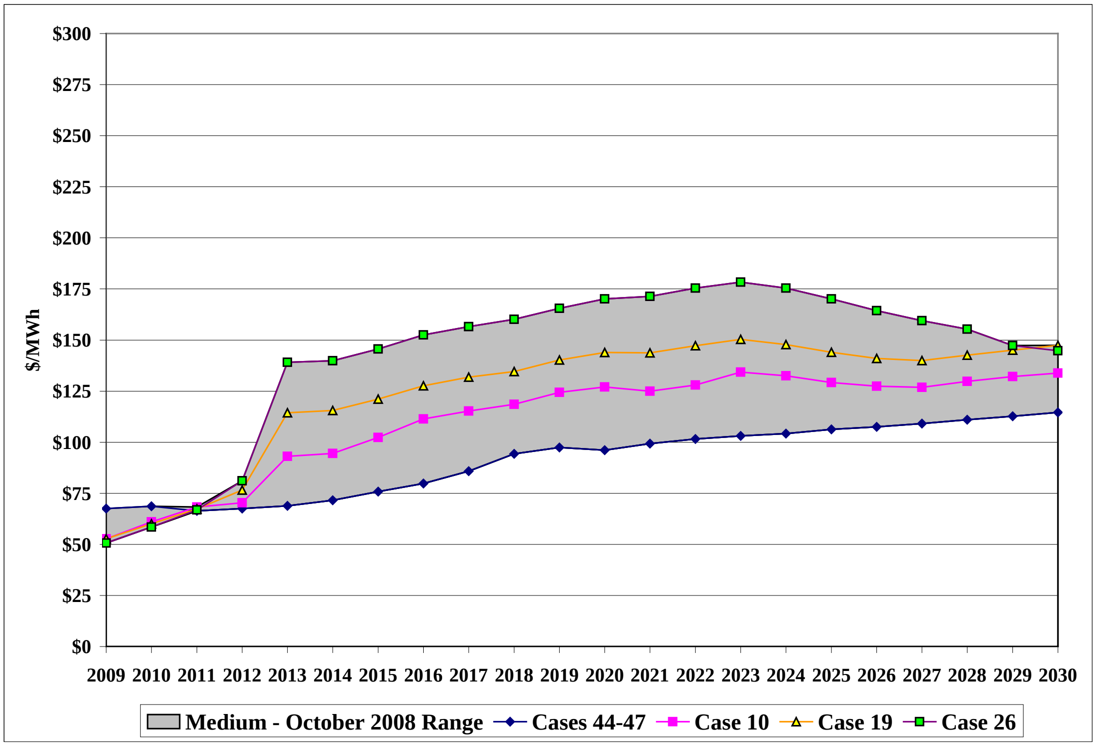


Figure 7.13 – Western Electricity Prices from the Medium June 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Low June 2008 Forecast

The underlying June 2008 low gas price forecast is defined by low oil prices and an extended period of growth from unconventional natural gas fields. Through this period of growth in unconventional production, it is assumed that knowledge transfer and technological advancements keep production costs on the decline. Concurrently, global LNG projects continue to come online while Asian markets experience growth in pipeline gas from China and India. Consequently, despite strong domestic growth from unconventional gas fields, LNG imports are diverted to the North American market. On the demand front, recent gas price spikes steer new power plant development away from gas-fired capacity, thereby keeping demand from the electric sector at bay. Given that the low price forecast is already defined by suppressed demand and an optimistic outlook for low cost supply, a second low price forecast was not added in October 2008. Figure 7.14 shows Henry Hub benchmark prices and Figure 7.15 includes the accompanying electricity prices for the forecasts developed around the low June 2008 gas price projection.

Figure 7.14 – Henry Hub Natural Gas Prices from the Low June 2008 Underlying Forecast

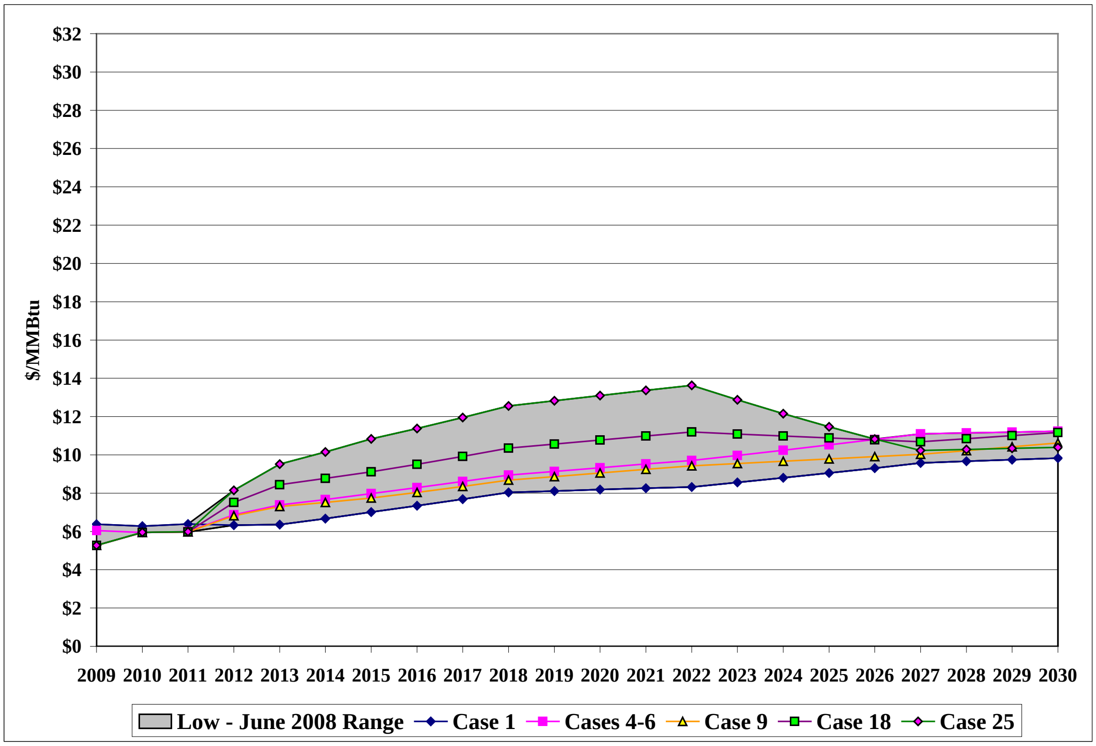
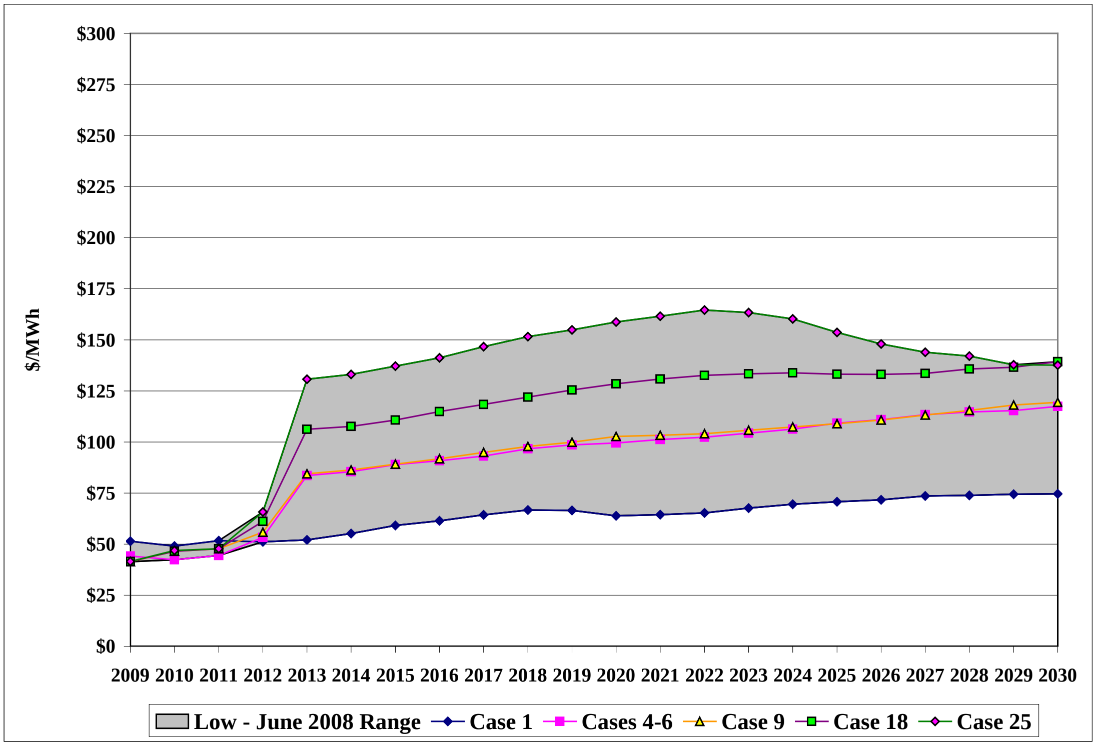


Figure 7.15 – Western Electricity Prices from the Low June 2008 Underlying Gas Price Forecast



[1] Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Emission Price Forecasts

As events unfolded in 2008, it became increasingly clear that policy uncertainty is not reserved only for greenhouse gas emissions. In February 2008, the D.C. Circuit Court of Appeals vacated the Clean Air Mercury Rule (CAMR) on the grounds that it was illegal for the Environmental Protection Agency (EPA) to de-list mercury as a hazardous pollutant. With this ruling, it became evident that a CAMR-based trading program for mercury allowances would not be implemented, and consequently, mercury allowance price forecasts are not studied in this IRP. Nonetheless, across all cases evaluated, it is assumed that all coal-fired supply side resource options are outfitted with activated carbon injection control technologies. (All fossil fuel plants are assigned a mercury emission rate, and mercury emissions for each portfolio are reported in Chapter 8.)

As with mercury, events in 2008 also introduced increased uncertainty to the sulfur dioxide (SO_2) allowance market. In July 2008, the D.C. Circuit Court of Appeals vacated the Clean Air Interstate Rule (CAIR) citing several fatal flaws and remanded it back to EPA with direction to promulgate a new rule. Once CAIR was vacated, the value of existing SO_2 allowances, which could be used for future CAIR compliance needs, dropped overnight and prices fell precipitously. The market continued to function, albeit at light trading volumes and at prices detached from long-term fundamentals.

EPA petitioned the court for rehearing in September 2008, and the court asked petitioners from the case to file briefs stating their opinion on EPA's request. In December 2008, the court reversed its previous finding and remanded the rule back to EPA without vacating the rule in its entirety. In its December decision, the court explained that its vacatur would sacrifice clear benefits to public health and the environment while EPA fixes the rule. While the latest court ruling reinstates CAIR, it only does so until EPA can promulgate a new rule that addresses the problems identified in the original finding or until legislative action is taken. Consequently, prices for existing SO_2 allowance prices remain below the likely cost of future compliance.

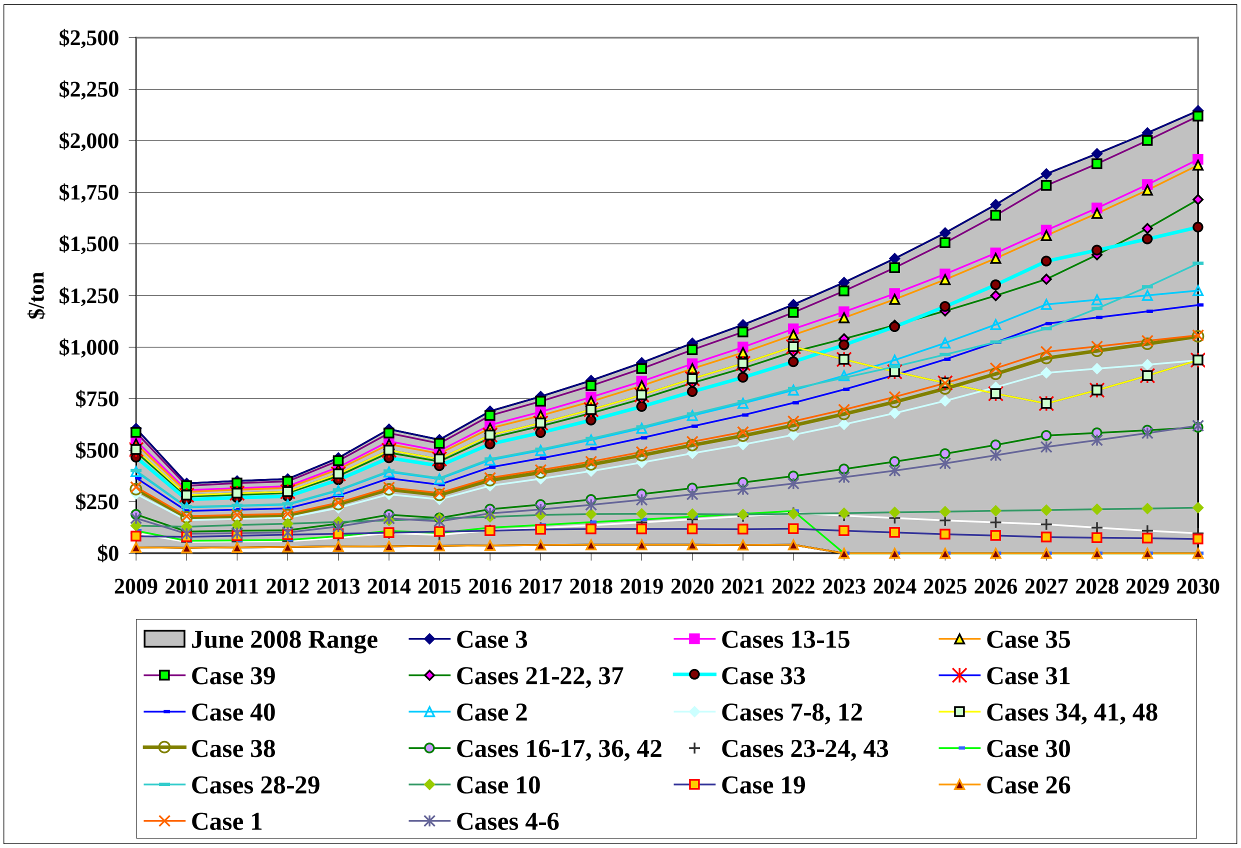
Given the tremendous uncertainty in the SO_2 allowance market and considering that current prices have departed from a fundamentals-view of future compliance costs, two sets of reference SO_2 allowance price forecasts were developed for this IRP. The two reference SO_2 allowance price forecasts are adjusted in response to the specific variables for any given case in much the same way that the underlying gas price forecasts are adjusted. As case variables are changed, IPM® is used to produce an associated SO_2 allowance price response, which in turn is used to make adjustments to the appropriate reference price forecasts. Table 7.7 summarizes SO_2 allowance prices developed for the two reference forecasts.

Table 7.7 – Reference SO_2 Allowance Price Forecast Summary (nominal $/ton)

Forecast Name	2010	2015	2020	2025	2030
June 2008	$205	$333	$616	$940	$1,204
August 2008	$157	$206	$232	$247	$271

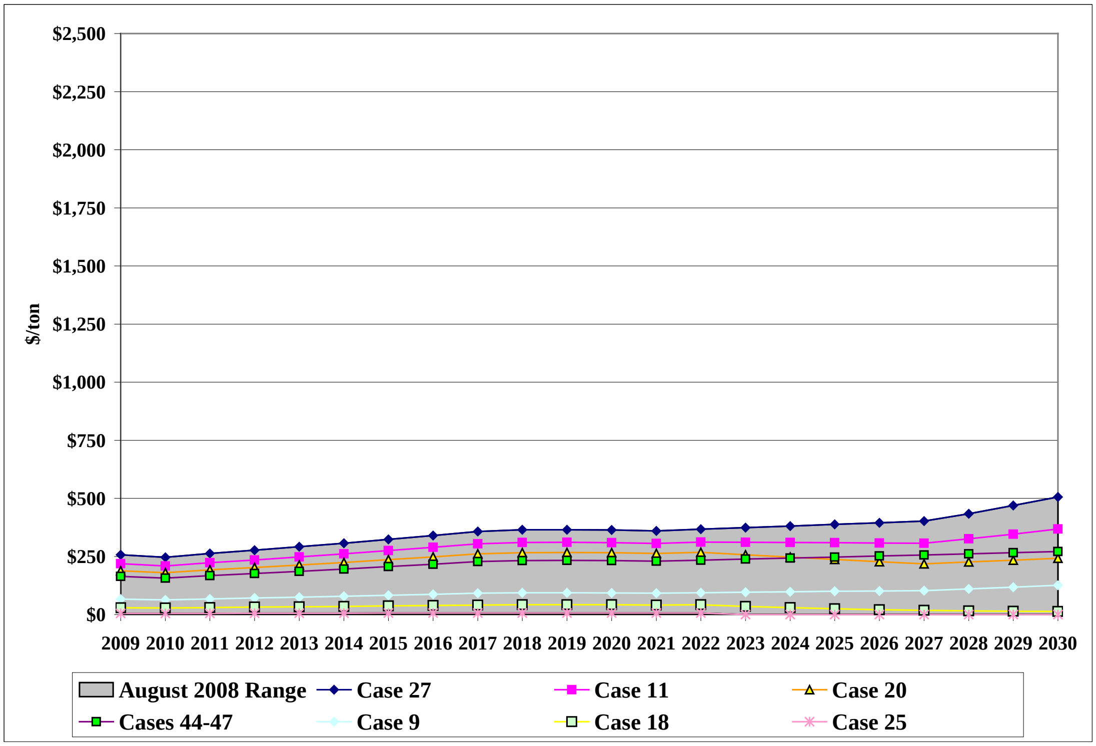
The June 2008 reference forecast reflects a combination of market forwards and a fundamentals-based price forecast. The market portion of the forecast extends through 2012 and reflects forwards as of June 20, 2008. Prices from 2013 through 2015 are derived as a gradual transition from the market forwards to the subsequent fundamentals-based forecast, which is applied starting in 2016. The fundamentals-based forecast is indicative of future compliance costs tied to the marginal cost of installing scrubbers on enough units to achieve the emission reduction targets established under CAIR. Figure 7.16 shows SO_2 allowance prices for the forecasts developed around the June 2008 reference price projection.

Figure 7.16 – SO_2 Allowance Prices Developed off of the June 2008 Reference Forecast



The August 2008 reference SO_2 allowance price forecast is based almost entirely upon market forwards as of August 7, 2008. The market is used for prices through 2021 and escalated at inflation thereafter. Under this reference price forecast, it is assumed that the uncertainties plaguing the SO_2 allowance market will continue into the foreseeable future. Figure 7.17 shows SO_2 allowance prices for the forecasts developed around the August 2008 reference price projection.

Figure 7.17 – SO_2 Allowance Prices Developed off of the August 2008 Reference Forecast



OPTIMIZED PORTFOLIO DEVELOPMENT

For Phase 3, the System Optimizer is executed for each set of case assumptions, generating an optimized investment plan and associated real levelized present value of revenue requirements (PVRR) for 2009 through 2028. System Optimizer operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the 20-year study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for each load area represented in the model).

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

For capital cost derivation, System Optimizer uses annual capital recovery factors to address end-effects issues associated with capital-intensive investments of different durations and in-service dates. PacifiCorp used the real-levelized capital costs produced by the System Optimizer for portfolio cost reporting by the PaR model.

Representation and Modeling of Renewable Portfolio Standards

PacifiCorp incorporates annual system-wide renewable generation constraints in the System Optimizer model to ensure that each optimized portfolio meets state Renewable Portfolio Standard (RPS) requirements.[40] For the base case RPS requirement, current Oregon, Utah, Washington, and California rules are followed. The resulting system generation requirement, using the state end-use energy forecasts as the starting point, reaches two percent of system load for 2011-2014, five percent for 2015-2019, six percent for 2020-2024, and 15 percent for 2025-2028. A key assumption backing the system-wide RPS representation is that all of PacifiCorp's state jurisdictions will adopt renewable energy credit (REC) trading rules through the Multi-state Process, thus enabling sales and purchase of surplus banked RECs.

RPS modeling is conducted as a two-step process. First, for each case the System Optimizer generates a portfolio without any RPS constraints applied. Determining whether the portfolio meets the RPS constraints is an off-line exercise utilizing a spreadsheet accounting model. The main components of the model include for each applicable state (1) the annual RPS requirement, (2) the annual generation from qualifying existing renewable facilities and resources selected by the System Optimizer, and (3) tracking of annual cumulative surplus REC bank balances. The qualifying generation for the all states, divided by the system load, represents the RPS compliance percentage. If this compliance percentage falls short of the generation requirement for a given year, available surplus banked RECs are applied. A portfolio is RPS-compliant if the RPS compliance percentage exceeds the RPS generation requirement for all years.

For step two, if the portfolio is not RPS-compliant then PacifiCorp re-runs the System Optimizer model with the annual RPS constraints turned on. To the extent the RPS requirement is not met, the model will add eligible resources to ensure compliance. Comparison of the costs for the RPS non-compliant and compliant portfolios indicates the incremental cost of RPS compliance with additional renewable resources.[41]

For each case, an RPS compliance report was generated. This report shows the annual system RPS requirements, REC bank balances, REC-adjusted qualifying generation, RPS compliance percentages, and the system load used in the calculations. The report also includes a line chart comparing the RPS compliance and system generation requirements percentages for both the base and high RPS scenarios. The RPS compliance reports are included in Appendix A.

Modeling Front Office Transactions and Growth Resources

Front office transactions, described in Chapter 6, are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization model-

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[40] The model currently is designed to treat RPS constraints as a generation percentage of system load. PacifiCorp is working with the model vendor on enhancements that enable representation of load-based RPS requirements for multiple jurisdictions.

[41] This two-step approach is intended to address a Utah commission 2007 IRP acknowledgment order requirement.

ing, System Optimizer engages in market purchase acquisition—both front office transactions, and for hourly energy balancing, spot market purchases—to the extent it is economic given other available resources. The model can select virtually any quantity of FOT generation up to limits imposed for each case, in any study year, independently of choices in other years. However, once a front office transaction resource is selected, it is treated as a must-run resource for the duration of the transaction period. For this IRP, front office transactions are available for all years in the study period. (In contrast, front office transactions were only modeled through 2018 in the 2007 IRP, after which the model could select only growth resources to meet load growth.)

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

Another resource type included in the IRP models is the *growth resource*. This resource is intended for capacity balancing in each load area to ensure that capacity reserve margins are met in the out years of each simulation (after 2020). The System Optimizer model can select an annual flat or third-quarter heavy load hour energy pattern priced at forward market prices appropriate for each load area. Growth resources are similar to front office transactions, except that they are not transacted at market hubs.

Modeling Wind Resources

Wind resources are modeled with an hourly generation shape that reflects average hourly wind variability. The shapes are scaled to capacity factors reflecting representative wind resource qualities across PacifiCorp's system. (See Chapter 6 for more details on wind resource options.) The hourly generation shape is repeated for each year of the simulation, and is used in both the System Optimizer and Planning and Risk models.

Because System Optimizer is not a detailed chronological unit commitment and dispatch model, the cost impacts of wind tied to unit commitment are not captured. Also, system costs and reliability effects associated with intra-hour wind variability are not captured.

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $11.75/MWh (in 2008 dollars) for portfolio modeling. The source of this value was Portland General Electric Company's wind integration study, which assumed penetration of over 1,000 MW of wind capacity with no addition of supporting flexible thermal resources. This value was selected as a reasonable proxy to use until PacifiCorp's own wind integration cost study is completed.

To reflect realistic system resource addition limits tied to transmission availability and other factors such as resource market availability and procurement constraints, System Optimizer was constrained to select up to 500 MW per year of wind prior to 2014, and 750 MW per year in 2014 and thereafter.

Modeling Fossil Fuel Efficiency Improvements

For all IRP modeling, PacifiCorp used forward-looking heat rates for existing fossil fuel plants, which account for plant efficiency improvement plans. Previously the Company used four-year historical average heat rates. This change ensures that such planned improvements are factored in the optimized portfolios and stochastic production cost simulations, in line with the goals of the PURPA fossil fuel generation efficiency standard that is part of the 2005 Energy Policy Act.

MONTE CARLO PRODUCTION COST SIMULATION

Phase 4 entails simulation of each optimized portfolios from Phase 3 using the Planning and Risk model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. Three stochastic simulations were executed for the three CO_2 tax levels: $0/ton, $45/ton, and $100/ton. These levels reflect a reasonable middle value along with bookends adopted for portfolio development. All the simulations used the October 2008 forward price curves as the expected gas and electricity price forecast values. This maintains comparability with the price forecast assumptions used for the 2009 business plan, as well as with the business plan reference cases, numbers 46 and 47.

The PaR simulation also incorporates stochastic risk in its production cost estimates by using a stochastic model and Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability for new resources. (For existing thermal units, planned maintenance schedules were used.[42]) Although wind resource generation was not varied in the same way as the other stochastic variables, the hour-to-hour generation does vary throughout the year, but the pattern is repeated identically for all study years (2009-2028) and Monte Carlo iterations.

The Stochastic Model

The stochastic model used in PaR is a two-factor (a short-run and a long-run factor) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand.

Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to market prices, the long-run factor should be understood as an expected equilibrium, with the Monte Carlo draws defining a possible forward equilibrium state. In the case of regional electricity loads, the Monte Carlo draws define possible forward paths for electricity demand.

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[42] Stochastic simulation of existing thermal unit availability is undesirable because it introduces cost variability unassociated with the evaluation of new resources, which confounds comparative portfolio analysis.

Stochastic Model Parameter Estimation

Stochastic model parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The econometric analysis uses 48 months of historical data for parameter estimation.

The long-run parameters are derived from a "random-walk with drift" regression. The standard error of the random-walk regression defines the long-run volatility for the regional electricity load variables. In the case of the natural gas and electricity market prices, the standard error of the random walk regression is interpolated with the volatilities from the Company's official forward price curves over the twenty-year IRP study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets, as well as the impacts from changes in expected regional electricity loads.

PacifiCorp's econometric analysis is performed for the following stochastic variables:

- Fuel prices (natural gas prices for the Company's western and eastern control areas),
- Electricity market prices for Mid-Columbia (Mid C), California – Oregon Border (COB), Four Corners, and Palo Verde (PV),
- Electric transmission area loads (California, Idaho, Oregon, Utah, Washington and Wyoming regions)
- Hydroelectric generation

For outage modeling, PacifiCorp relies on the PaR model's Monte Carlo simulation method to create a distributed outage pattern for new resources. PacifiCorp does not estimate stochastic parameters for plant outages.

Monte Carlo Simulation

During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are of percentage deviations from the expected forward value of the variables, and are the same for each Monte Carlo simulation. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

The PaR model is configured to conduct 100 Monte Carlo simulation runs for the 20-year study period, so that each of the 100 simulations has its own set of stochastic parameters and shocked forecast values. The end result of the Monte Carlo simulation is 100 production cost runs (iterations) reflecting a wide range of portfolio cost outcomes.

Figures 7.18 through 7.21 show the 100-iteration frequencies for market prices resulting from the Monte Carlo draws for two representative years, 2009 and 2018. Figures 7.22 through 7.26 show the annual loads by load area at different percentiles: 10th, 25th, 50th, 75th, and 90th. Figure 7.27 shows the 25th, 50th, and 75th percentiles for hydroelectric generation.

Figure 7.18 – Frequency of Western (Mid-Columbia) Electricity Market Prices for 2009 and 2018

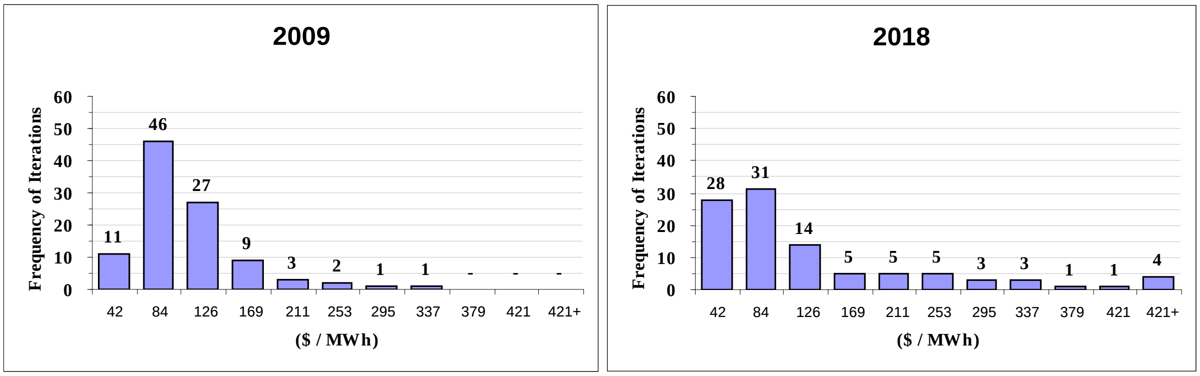


Figure 7.19 – Frequency of Eastern (Palo Verde) Electricity Market Prices, 2009 and 2018

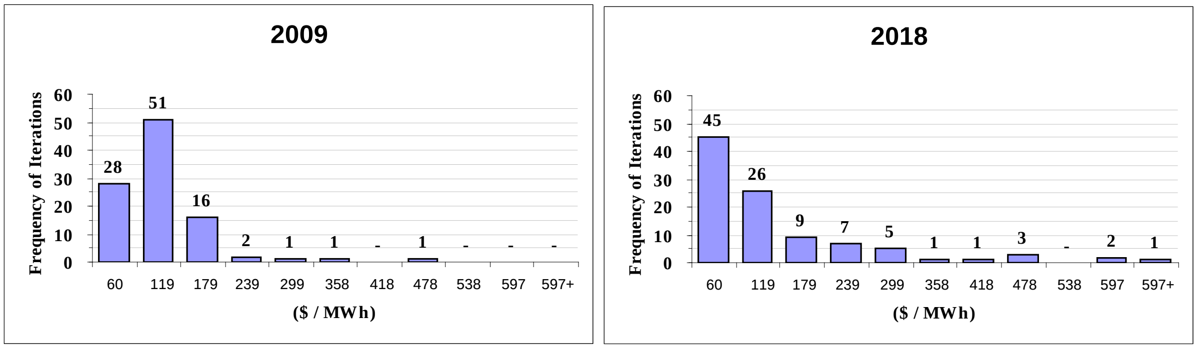


Figure 7.20 – Frequency of Western Natural Gas Market Prices, 2009 and 2018

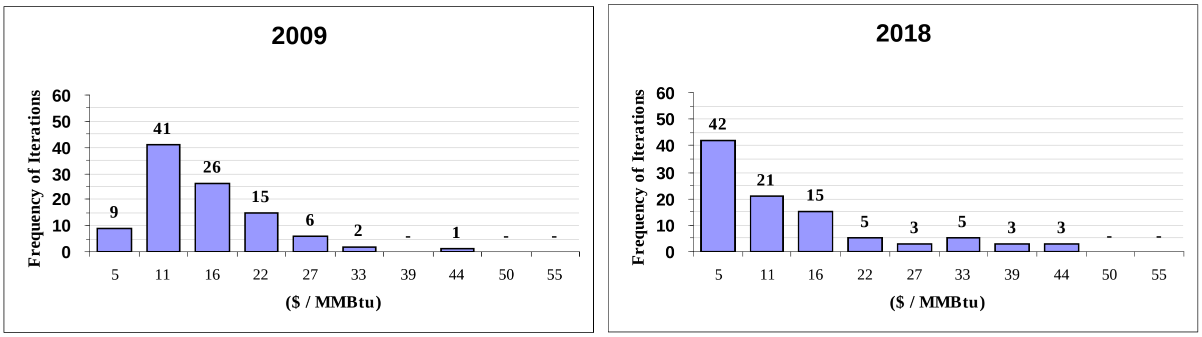


Figure 7.21 – Frequency of Eastern Natural Gas Market Prices, 2009 and 2018

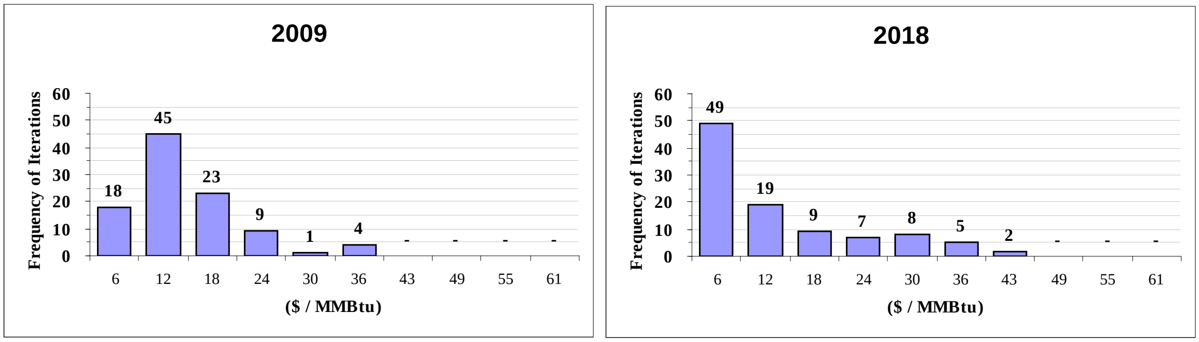


Figure 7.22 – Frequencies for Idaho (Goshen) Loads

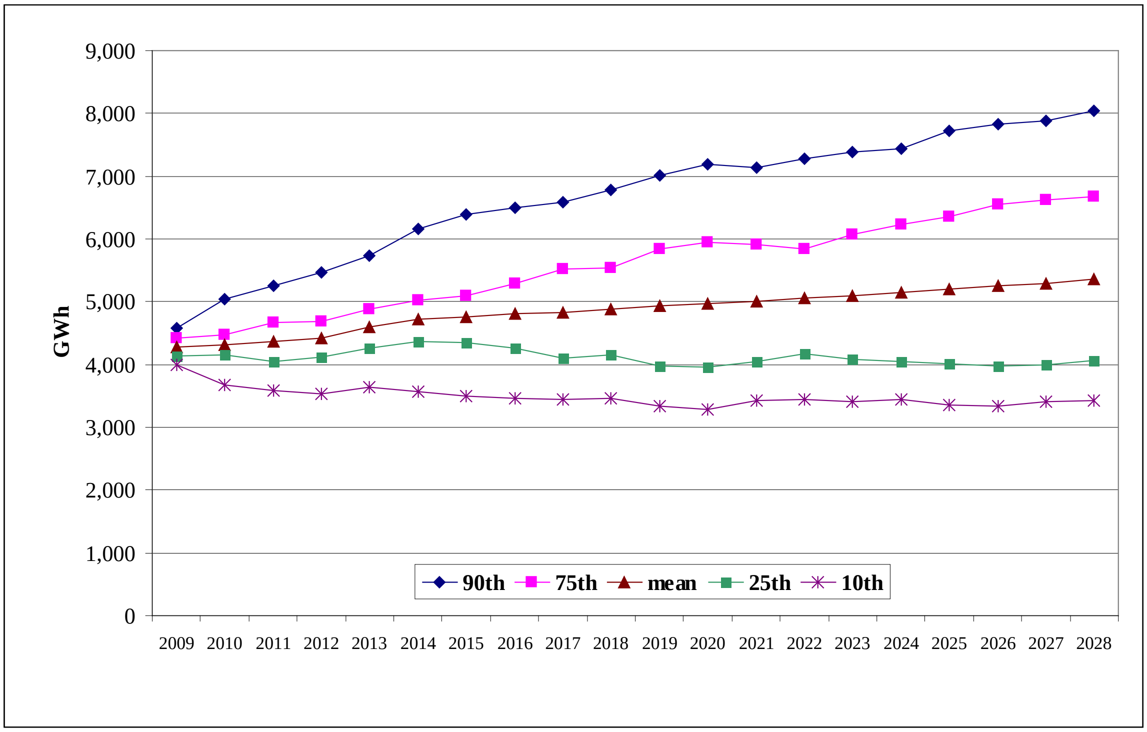


Figure 7.23 – Frequencies for Utah Loads

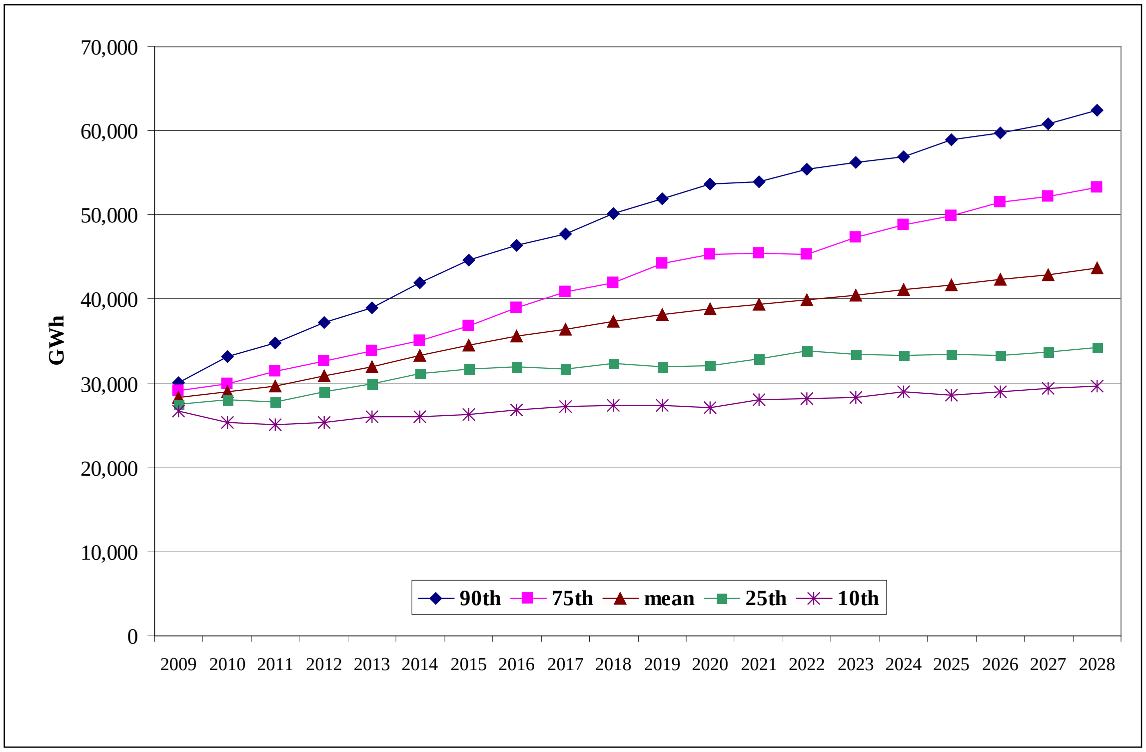


Figure 7.24 – Frequencies for Washington Loads

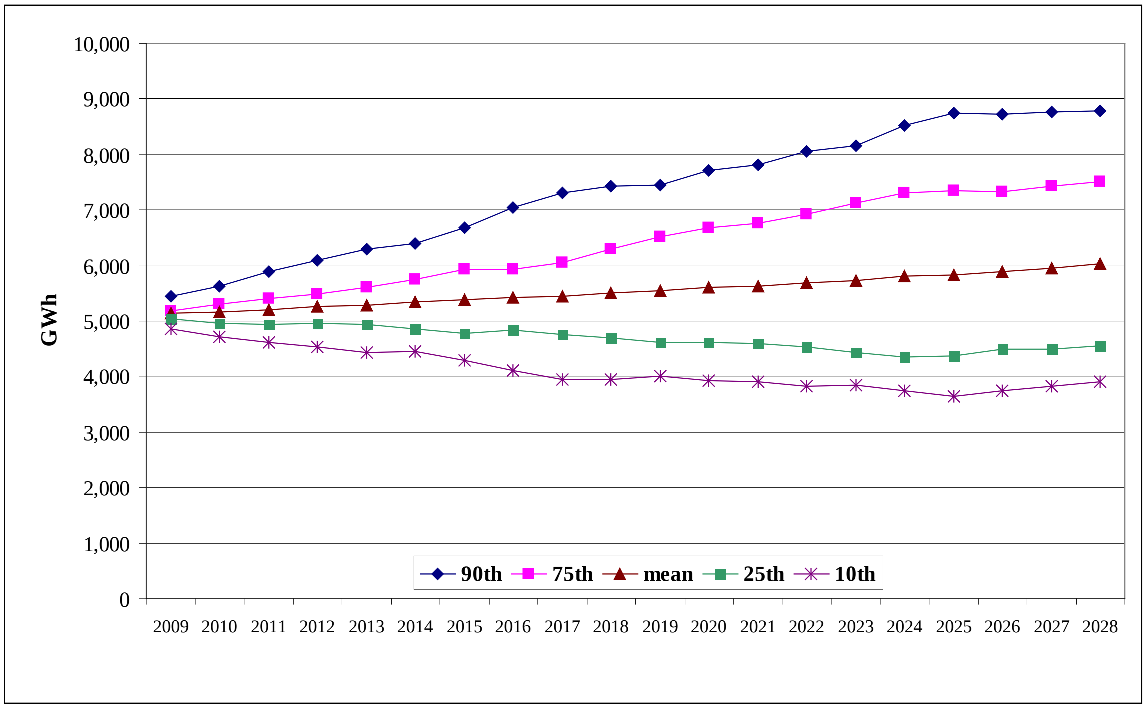


Figure 7.25 – Frequencies for West Main (California and Oregon) Loads

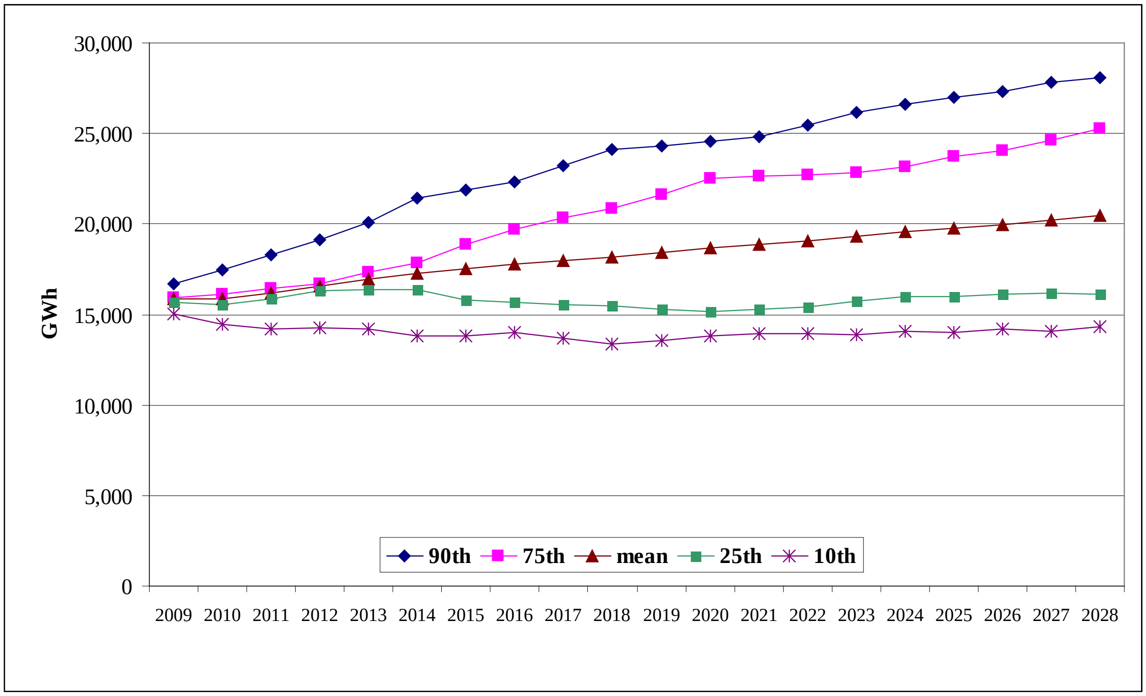


Figure 7.26 – Frequencies for Wyoming Loads

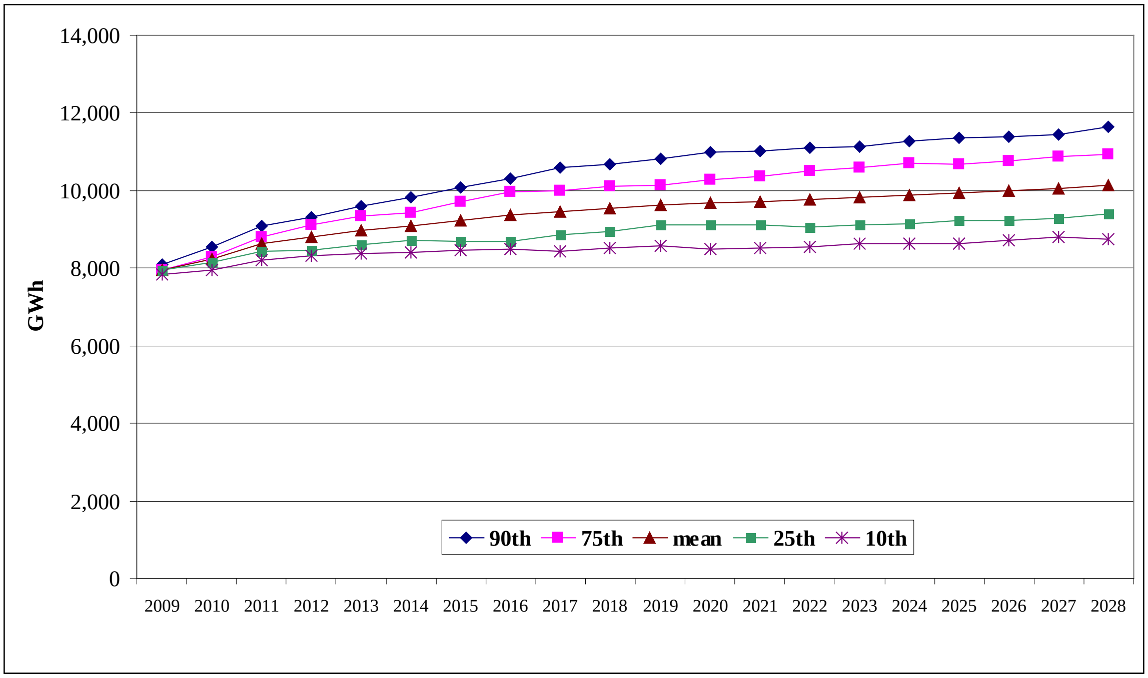
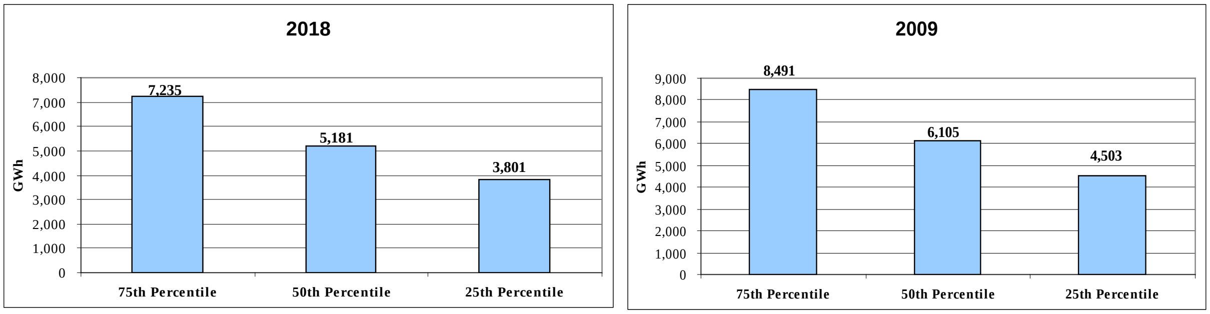


Figure 7.27 – Hydroelectric Generation Frequency, 2009 and 2018



PacifiCorp derives expected values for the Monte Carlo simulation by averaging run results across all 100 iterations. The Company also looks at subsets of the 100 iterations that signify particularly adverse cost conditions, and derives associated cost measures as indicators of high-end portfolio risk. These cost measures, and others used to rank portfolio performance, are described in the next section.

PORTFOLIO PERFORMANCE MEASURES

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

Cost

- Mean PVRR (Present Value of Revenue Requirements)
- Risk-adjusted mean PVRR
- Minimum PVRR cost exposure under CO_2 tax outcomes
- Customer rate impact
- Capital costs for the first ten years of the simulation period (2009-2018) and the total simulation (2009-2028)

Risk

- Upper-tail Mean PVRR
- 95th Percentile PVRR
- Production cost standard deviation

Supply Reliability

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

PacifiCorp reports the portfolio results for each CO_2 tax simulation, the straight average for the three CO_2 tax simulations, and multiple probability-weighted averages. The multiple probability-weighted averages reflect $5/ton increments of the expected value (EV) CO_2 tax, ranging from

\$15/ton to \$70/ton. This range is in line with long run values that have appeared in federal and state legislative proposals.[43] The average values are converted to a normalized, 1-to-10 scaled score to preserve relative differences between measure results when combining the scores for composite ranking of the portfolios.

In addition to these stochastic measures, PacifiCorp reports fuel source diversity statistics and the emission footprint of each portfolio, focusing on generator emissions.

The following sections describe in detail each of these performance measures as well as the fuel source diversity statistics.

Mean PVRR

The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs for new resources determined by the System Optimizer model. The PVRR is reported in 2009 dollars as of January 1, 2009.

The net variable cost from the PaR simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales, and costs associated with making up for generation deficiencies (Energy Not Served costs; see the section on ENS below for background on ENS and the representation of ENS costs in the PaR model.) The variable costs included are not only for new resources but existing system operations as well. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components in the stochastic mean PVRR include renewable production tax credits and emission externality costs, such as a CO_2 tax.

The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO_2 cost adders. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand-side resources as evaluated in this IRP.

Risk-adjusted Mean PVRR

This measure—risk-adjusted PVRR for short—is calculated as the stochastic mean PVRR plus the expected value, EV, of the 95th percentile PVRR, where $EV = PVRR_{95} \times 5\%$. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations conducted for each production cost run.

The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts without eliciting and applying subjective weights that express the utility of trading one cost attribute for another.

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[43] For example, see, Metcalf, G., et al, Analysis of U.S. Greenhouse Gas Tax Proposals (Massachusetts Institute of Technology, Joint Program on the Science and Policy of Global Change, Report No. 160, April 2008). As an example of a state legislative CO_2 tax proposal, the Kansas House of Representatives considered a \$37/ton CO_2 tax to be levied on the state's electric utilities.

PacifiCorp also presents scatter-plot graphs of the stochastic mean PVRR versus upper-tail mean PVRR for portfolios as a means to visualize the tradeoff between expected and high-cost outcomes.

Minimum Cost Exposure under Alternative Carbon Dioxide Tax Levels

Cost exposure is the difference between a portfolio's risk-adjusted PVRR and the risk-adjusted PVRR of the best-performing portfolio for a given CO_2 tax level modeled in the Monte Carlo simulation. Each portfolio is ranked on the basis of the size of its maximum cost exposure realized under the three CO_2 tax levels: $0/ton, $45/ton, and $100/ton.

This ranking scheme is based on the Minimax Regret decision criterion, which focuses on avoiding the worst possible consequences that could result when making a decision. In decision theory, "regret" is defined as the exposure between a course of action taken and the best course of action possible given a particular state of nature.[44] If the decision-maker selects the course of action that turns out to be the best possible one, then the regret is zero. Conversely, the maximum regret occurs if the selected course of action results in the worst outcome among the possibilities. The minimax decision rule is to select the course of action that minimizes the maximum regret across the states of nature evaluated. This is a risk-averse stance applicable to decision-making under uncertainty.

To illustrate the application of the decision rule, the following matrix shows the cost outcomes given two alternative actions and two states of nature, designated as S_1 and S_2. Under state of nature S_1, the best possible cost outcome happens under Alternative 2; under state of nature S_2, the superior cost outcome happens under Alternative 1.

	Cost (Billion $)	
Alternative	**S_1**	**S_2**
1	18.00	23.00
2	10.00	28.00
Lowest Cost	**10.00**	**23.00**

To determine the maximum regret for the two alternatives, a loss matrix is constructed:

Loss Table (Billion $)

Alternative	**S_1**	**S_2**	**Maximum Regret**
1	8.00	0.00	**8.00**
2	0.00	5.00	**5.00**

The maximum regret for alternative 1 under state of nature S_1 is $8 billion, while the maximum regret for alternative 2 under state of nature S_2 is $5 billion. By applying the minimax decision

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[44] Regret is also called "opportunity loss", or the amount that would be lost by not picking the best alternative.

rule, alternative 2 would be selected because it has the lowest maximum loss under the two states of nature.

For PacifiCorp's minimax evaluation, the states of nature are the stochastic cost outcomes given the three CO_2 tax levels modeled in the Monte Carlo simulations ($0/ton, $45/ton, and $100/ton). The alternatives are the resource portfolios developed from the 21 core cases with the medium load growth assumption.

Customer Rate Impact

PacifiCorp calculates the customer rate impact associated with each of the portfolios based on the stochastic production cost results and capital costs reported for the portfolio by the System Optimizer model. The rate impact measure is the levelized net present value of the year-to-year changes in the customer dollar-per-megawatt-hour price for the period 2009 through 2028:

$$-PMT\left(NPV_{i=\{2010\rightarrow 2028\}}\left(\frac{Cost_i - Cost_{i-1}}{Load_i}\right)\right)$$

The cost in the rate numerator consist of the stochastic mean system operating cost (fuel cost, environmental cost, and variable O&M costs of all resources), combined with the fixed O&M and capital costs of the new supply-side and transmission resources.[45] The rate denominator is the retail load.

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

Capital Cost

The total capital cost measure is the sum of the capital costs for generation resources and transmission, expressed as a net present value. The capital costs are reported by the System Optimizer for each portfolio. Capital costs for the first 10 years of the simulation period, as well as the entire simulation period, are reported. The ten-year capital cost view (for resources added in 2009-2018), is intended to indicate the relative rate impact of the portfolios attributable to resource construction costs during the period considered in PacifiCorp's business plan.

Risk Measures

For this IRP, PacifiCorp relies on four stochastic cost risk measures: upper-tail mean PVRR, 5th and 95th percentile PVRR, and the standard deviation of production costs.

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[45] New IRP resource capital costs are represented in 2008 dollars and grow with inflation, and start in the year the resource added. This method is used so resources having different lives can be evaluated on a comparable basis. The customer rate impacts will be lower in the early years and higher in the later years when compared to customer rate impacts computed under a rate-making formula.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the five highest production costs on a net present value basis. The portfolio's real levelized fixed costs are added to these five production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The fifth and ninety-fifth percentile stochastic PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles on the basis of production costs (net present value basis), respectively. These measures represent snapshot indicators of low-risk and high-risk stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted PVRR measure.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2009 through 2028.

Supply Reliability

Average and Upper-Tail Energy Not Served

Certain iterations of a PaR stochastic simulation will have "energy not served" or ENS.[46] Energy Not Served is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. This occurs when an iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour. Typically large load shocks and simultaneous unplanned plant outages are implicated in ENS events. (Deterministic PaR simulations do not experience ENS because there is no random behavior of model parameters; for example, loads increase in a smooth fashion over time.) Consequently, ENS, when averaged across all 100 iterations, serves as a measure of the stochastic reliability risk for a portfolio's resources.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2009 through 2028 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Results using the $45/ton CO_2 tax are reported, as the tax level does not have a material influence on ENS amounts.

One change from previous IRPs related to the handling of ENS is the estimation of ENS costs included in the portfolio stochastic PVRR. In previous IRPs, PacifiCorp applied a single ENS cost for the PaR model, using the FERC price cap as a reasonable cost proxy for acquiring emergency power. PacifiCorp recognizes that, in practice, the planning response to significant ENS is different for short-run versus long-run ENS expectations. In the short-run, the Company would have recourse to few remedial options, and would expect to pay a large premium for emergency power. On the other hand, the Company has more planning options with which to respond to long-term forecasted ENS growth, including acquisition of peaking resources. Consequently, a

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[46] Also referred to as Expected Unserved Energy, or EUE.

tiered pricing scheme has been applied to ENS quantities generated by the Planning and Risk model. The ENS cost is set to $400/MWh (real dollars) for the first 50 GWh/yr of ENS, $200/MWh for the next 100 GWh/yr, and $100/MWh for all quantities above 150 GWh/yr. For large forecasted ENS quantities that occur in the out years of the study period, the acquisition of peaking generation would become cost-effective, with the $100/MWh reflecting the long-run all-in cost for such generation.

Loss of Load Probability

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

Mathematically, LOLP defined as:

$$\mathbf{LOLP} = \text{Prob}(\mathbf{S} < \mathbf{L})$$

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

Traditionally LOLP was calculated for each hour of the year, converted to a measure of statistically expected outage times or number of outage events (depending on the model), and summed for the year. The annual measure estimates the generating system's reliability. A high LOLP generally indicates a resource shortage, which can be due to generator outages, insufficient installed capacity, or both. Target values for annual system LOLP depend on the utilities' degree of risk aversion, but a level equivalent of one day per ten years is typical.

For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, only events that occur at the time of the regional peak are the ones likely to have significant consequences. Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Chapter 8, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a “significant event” occurring the winter season.

Fuel Source Diversity

For assessing fuel source diversity on a summary basis for each portfolio, PacifiCorp calculated the new resource generation shares for four broad fuel-type categories as reflected in the System Optimizer expansion plan:

- Renewables and DSM (“no fuel” generation plus a small quantity of biomass fuel)
- Natural gas
- Market
- Coal, including all types of coal-based technologies selected for the expansion plan
- Nuclear

To account for the timing impact of the assumed availability of coal and nuclear resources in the portfolios, the generation shares are reported for years 2013, 2020, and 2028. Conventional supercritical coal plants are picked up in the 2020 and 2028 snapshots, while nuclear and clean coal resources are picked up in the 2028 snapshot.

Another perspective on fuel diversity is the nameplate capacity mix for the portfolios. Appendix A contains area charts for all portfolios developed that show the resource nameplate capacity mix by year. Nameplate capacity for resources selected by the System Optimizer is grouped into the following new resource categories: gas, DSM, distributed generation, wind, other renewables, clean coal, conventional coal, energy storage, other renewables, market purchases, and growth resources.

TOP-PERFORMING PORTFOLIO SELECTION

For this IRP, PacifiCorp has instituted a weighted scoring scheme that combines selected portfolio performance measures into an overall composite preference score. The cases selected for performance ranking include the core cases defined with the medium load growth assumption (to maintain cost comparability with respect to the amount of resources required) as well as cases 46 and 47 (the two business plan reference portfolios).

The measures used in the weighted scoring scheme, along with their importance weights (which sum to 1), include the following:

Table 7.8 – Measure Importance Weights for Portfolio Ranking

Cost Measures	**Weight**
Risk-adjusted PVRR	45%
Customer Rate Impact	20%
Capital Cost for 2009-2018	5%
Risk Measures	**Weight**
CO_2 Cost Exposure	15%
Production Cost Standard Deviation	5%
Average annual ENS	5%
Average Annual Probability of ENS events for July exceeding 25 GWh	5%
Total	**100%**

Risk-adjusted PVRR represents the long-run cost performance for a portfolio, accounting for the potential for a high-cost outcome and its associated cost on an expected value basis. Consequently, this criterion is given the largest weight among the performance measures. The customer rate impact measure gauges long-run retail rate variability for a portfolio; given two portfolios with equivalent long-run costs, the portfolio that has lower retail rate variability is preferred. The 10-year capital cost criterion reflects the role that near-term capital expenditures plays in determining portfolio affordability and financeability for purposes of business plan preparation.

For portfolio risk measures, cost exposure under alternative CO_2 tax levels reflects a portfolio's potential for avoiding worst-case cost outcomes given CO_2 regulatory policy uncertainty; it is a measure of CO_2 cost risk, and has been given the largest weight among risk measures included in the preference scoring process. The three other risk measures reflect variable cost variability and supply reliability attributes, and have been given a combined weight of 15 percent for preference scoring.

Table 7.9 shows a sample of the preference-scoring grid for the optimized portfolios. To determine the preference scores for the portfolios, PacifiCorp conducted the following steps:

1. Calculate the normalized (scaled from 1 to 10) rankings for the probability-weighted average stochastic cost measures (risk-adjusted PVRR, customer rate impact, CO_2 cost exposure, and the standard deviation of production costs). Rankings are determined for each of 12 expected value CO_2 tax levels, ranging from $15 to $70.
2. Calculate the normalized rankings for the 10-year capital costs, average annual ENS, and July event LOLP.
3. Populate the portfolio preference-scoring grid with the normalized rankings. The weighted ranking for each portfolio is the sum of each individual performance ranking multiplied by its importance weight. These weighted rankings are then converted to final preference scores by scaling the rankings to a 1 to 10 range.

Table 7.9 – Portfolio Preference Scoring Grid

	Cost Measures			Risk Measures					
Case [1/]	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1								0.0	0.0
2								0.0	0.0
3								0.0	0.0
5								0.0	0.0
8								0.0	0.0
9								0.0	0.0
10								0.0	0.0
11								0.0	0.0
14								0.0	0.0
17								0.0	0.0
18								0.0	0.0
19								0.0	0.0
20								0.0	0.0
22								0.0	0.0
24								0.0	0.0
25								0.0	0.0
26								0.0	0.0
27								0.0	0.0
29								0.0	0.0
46								0.0	0.0
47								0.0	0.0

Importance Weights	45%	20%	5%	15%	5%	5%	5%

The net result was a set of 12 preference-scoring grids, one for each expected value CO_2 tax level. For determining the top-performing portfolios, PacifiCorp calculated the average of the preference scores across the CO_2 tax levels, as well as inspected the variability of the scores as the CO_2 level increased.

The top three portfolios on the basis of the preference scores were selected as final preferred portfolio candidates. Three portfolios represent a manageable number in light of the data processing and model run-time requirements associated with phase 6, deterministic risk assessment of the top-performing portfolios.

SCENARIO RISK ASSESSMENT

The purpose of phase 6 is to determine the range of deterministic costs that could result given a fixed set of resources under varying gas/electricity price and CO_2 cost assumptions, the two main sources of portfolio risk. The Public Service Commission of Utah, in its acknowledgment order for PacifiCorp's 2007 IRP, directed the Company to consider this step for the 2008 IRP.

PacifiCorp used the System Optimizer to determine PVRRs for the three top-performing portfolios under a subset of the core cases (Scenario Risk Cases). For these runs, the System Optimizer dispatches the fixed set of portfolio resources as part of its least-cost portfolio solution. The PVRR comparisons thus indicate the production cost differences under the alternative cost scenarios.

As with the performance ranking process, PacifiCorp selected only those cases with the medium load growth assumption. Cases were also restricted to those using the June 2008 forward price curve. These selection rules resulted in 10 cases and total of 30 System Optimizer runs to support this analysis as shown in Table 7.10.

Table 7.10 – Cases Selected for Deterministic Risk Assessment

Case	CO_2 Tax Level (2008 dollars)	Base Gas Cost
1	$0/ton	Low
2	$0/ton	Medium
3	$0/ton	High
5	$45/ton	Low
8	$45/ton	Medium
14	$45/ton	High
17	$70/ton	Medium
22	$70/ton	High
24	$100/ton	Medium
29	$100/ton	High

In parallel with the stochastic risk analysis, PacifiCorp reports a measure of central tendency (mean PVRR) and variation (PVRR standard deviation) for the portfolio results, as well as ranked each portfolio and computed the rank sum as an overall performance indicator.

PREFERRED PORTFOLIO SELECTION AND ACQUISITION RISK ANALYSIS

The preferred portfolio is selected from the three top-performing portfolios on the basis of the portfolio preference scores, and then consideration of resource risks and fuel source diversity.

Using the preferred portfolio as the starting point, PacifiCorp conducts a next best alternative (NBA) analysis that applied a number of procurement risk scenarios to determine optimal portfolios in the event of unplanned circumstances. The focus of the NBA analysis is on key firm-planned and new resources reflected in the preferred portfolio.

8. MODELING AND PORTFOLIO SELECTION RESULTS

INTRODUCTION

This chapter reports modeling and portfolio performance evaluation results for the portfolios developed with alternate input assumptions using the System Optimizer model. The preferred portfolio is presented, along with a discussion of the relative advantages and risks associated with the top-performing portfolios.

Discussion of the portfolio evaluation results falls into the following 12 sections.
Portfolio Development Results – This section presents the System Optimizer resource portfolios, describing resource preferences as a function of the model input assumptions and profiling resource utilization patterns for each portfolio. Analysis results for several sensitivity case portfolios are also presented.

- <u>Stochastic Simulation Results - Candidate Portfolios</u> – This section reports the stochastic modeling results and cost/risk measure ranking results for each of the 21 candidate portfolios.
- <u>Load Growth Impact on Resource Choice</u> – This section compares the stochastic modeling results for portfolios developed with alternative load growth assumptions.
- <u>Capacity Planning Reserve Margin</u> – This section describes the stochastic cost and risk analysis of portfolios developed with 12 and 15 percent capacity planning reserve margins.
- <u>Probability-weighted Stochastic Cost Results</u> – This section reports the stochastic cost measures as probability-weighted averages of the results for the three CO_2 tax simulations: $0, $45, and $100/ton in 2008 dollars. These results are key inputs in the overall portfolio preference scoring process.
- <u>Fuel Source Diversity</u> – This section provides statistics on generation shares by fuel type for all the portfolios; three snap shot years are profiled: 2013, 2020, and 2028.
- <u>Emissions Footprint</u> – This section reports for each portfolio the annual emission quantities of CO_2, sulfur dioxide, nitrous oxides, and mercury for 2009-2028.
- <u>Top-performing Portfolio Selection</u> – This section describes the results of the portfolio cost/risk measure ranking and preference scoring, and identifies the four top-performing portfolios chosen as final candidates for preferred portfolio selection.
- <u>Scenario Risk Assessment</u> – This section describes the deterministic scenario analysis conducted for the three top-performing portfolios, concluding with a critique of the value of this type of analysis for the IRP.
- <u>Portfolio Impact of the 2012 Gas Resource Deferral Decision</u> – This section describes the portfolio analysis conducted to reflect the removal of the Lake Side II combined-cycle plant as a planned resource for 2012.
- Wind Resource Acquisition Schedule Development – This section discusses the model selection of wind resources and how business planning implementations must be considered.
- <u>Portfolio Impact of PacifiCorp's February 2009 Load Forecast</u> – This section presents the portfolio developed to account for a new load forecast prepared in February 2009.

- Preferred Portfolio Selection – This section compares the top-performing portfolios, profiling their relative advantages and risks and pulling in the portfolio analysis conducted for the Lake Side II construction cancellation and revised load forecast. The portfolio that is the most desirable after considering cost, risk and uncertainty is then presented.

PORTFOLIO DEVELOPMENT RESULTS

Tables 8.1 and 8.2 show the cumulative capacity additions by resource type for the portfolios for years 2009-2018 and 2009-2028, respectively. Megawatt amounts for front office transactions and growth resources represent annual averages: 20 years for FOT, and eight years for growth resources. (The detailed portfolio resource tables are included in Appendix A.)

Table 8.1 – Portfolio Capacity Additions by Resource Type, 2009 – 2018

				Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market Resources) [1/]							
Case	**PVRR**	**Gas Scenario / FPC**	**CO2 Price**	**SCPC**	**Gas**	**Wind**	**Dist. Gen**	**Market Purchases (10-yr Avg)**	**Other Renewables**	**DSM Class 1**	**DSM Class 2**
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)											
1	$20,045	Low - June 2008	$0		261		124	748		108	716
2	$21,512	Medium - June 2008	$0	600	261	140	85	646	35	2	890
3	$19,503	High - June 2008	$0	790		3,291	95	530	155	7	982
5	$40,526	Low - June 2008	$45		261	1,050	95	691	35	2	901
8	$41,372	Medium - June 2008	$45			2,400	147	663	120	7	955
9	$40,204	Low - Oct 2008	$45		261	1,280	95	690	35	2	899
10	$40,319	Medium - Oct 2008	$45			2,400	117	679	155	7	949
11	$40,559	High - Oct 2008	$45	600		4,814	103	546	155	7	1,001
14	$39,949	High - June 2008	$45	600		5,355	107	500	155	7	1,018
17	$51,207	Medium - June 2008	$70			3,900	110	613	155	7	985
18	$49,745	Low - Oct 2008	$70			3,900	110	640	155	7	954
19	$50,102	Medium - Oct 2008	$70			4,100	110	620	155	7	975
20	$50,536	High - Oct 2008	$70			5,250	104	602	155	7	1,007
22	$49,983	High - June 2008	$70	600		5,750	101	514	155	7	1,048
24	$60,693	Medium - June 2008	$100			5,739	112	565	155	7	1,009
25	$58,838	Low - Oct 2008	$100			5,250	112	742	155	7	1,000
26	$59,660	Medium - Oct 2008	$100			5,250	112	661	155	7	1,007
27	$60,484	High - Oct 2008	$100			5,750	110	648	155	7	1,045
29	$57,635	High - June 2008	$100			5,750	158	538	155	110	1,079
46	$21,532	Medium - Oct 2008	$8, C&T		174	600	136	641		19	906
47	$20,863	Medium - Oct 2008	$8, C&T		174	822	136	646		29	903
Low Load Growth Core Cases											
4	$34,612	Low - June 2008	$45			300	91	216	35		882
7	$34,582	Medium - June 2008	$45			1,800	91	172	85		920
13	$31,076	High - June 2008	$45	600		4,610	95	121	155		1,004
16	$43,523	Medium - June 2008	$70			3,599	109	116	155		962
21	$40,517	High - June 2008	$70			5,750	95	134	155		1,017
23	$51,692	Medium - June 2008	$100			5,559	111	101	155		1,005
28	$47,806	High - June 2008	$100			5,750	95	242	155		1,017
High Load Growth Core Cases											
6	$48,140	Low - June 2008	$45		1,363	904	192	755	155	126	957
12	$50,146	Medium - June 2008	$45	600	888	1,907	151	748	155	107	994
15	$50,914	High - June 2008	$45	600	261	5,750	153	771	655	114	1,079
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth											
30	$48,541	Medium - June 2008	$45 to $179			4,400	110	621	155	7	1,003
31	$47,552	High - June 2008	$45 to $179			5,750	110	533	155	7	1,072
Sensitivity Case - High Cost Outcome											
33	$69,949	High - June 2008	$100	600	577	5,750	158	662	655	126	1,113
Sensitivity Cases - Clean Base-Load Generation Availability											
34	$40,564	Medium - June 2008	$45			3,183	138	647	85	7	950
35	$39,853	High - June 2008	$45	600		5,000	97	528	120	7	1,015
36	$51,242	Medium - June 2008	$70			4,200	147	681	120	7	1,002
37	$48,949	High - June 2008	$70			5,750	95	595	120	7	1,019
Sensitivity Cases - High Plant Construction Costs											
38	$41,974	Medium - June 2008	$45			1,605	138	665	85	64	968
39	$34,791	High - June 2008	$45	600		3,182	142	493	120	109	1,020
Sensitivity Case - System-wide Oregon CO2 Reduction Targets											
40	$24,761	Medium - June 2008	Hard Cap			1,241	124	677	85	104	920
Sensitivity Cases - Planning Reserve Margin, 15%											
41	$41,542	Medium - June 2008	$45		261	1,934	151	776	155	25	954
42	$51,420	Medium - June 2008	$70		261	3,600	110	764	155		983
43	$60,905	Medium - June 2008	$100			5,750	154	713	155	105	1,036
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)											
44	$21,249	Medium - Oct 2008	$8, C&T	600		1,746	132	632	85	109	900
45	$20,875	Medium - Oct 2008	$8, C&T	600	261	721	89	654	35	2	877
Sensitivity Case - Class 3 DSM for Peak Load Reduction											
48	$41,268	Medium - June 2008	$45			2,400	107	643	85	121	945

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

Table 8.2 – Portfolio Capacity Additions by Resource Type, 2009 – 2028

				Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market and Growth Resources) [1/]											
Case	PVRR	Gas Scenario / FPC	CO2 Price	SCPC	SCPC w/ CCS	IGCC w/ CCS	Gas	Wind	Dist. Gen	Nuclear	Market Purchases (20-yr Avg)	Growth Resource (8-yr Avg, 2021-2028)	Other Renewables	DSM Class 1	DSM Class 2
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)															
1	$20,045	Low - June 2008	$0				261		130		1,102	859		108	1,537
2	$21,512	Medium - June 2008	$0	600			261	941	109		880	524	35	2	1,815
3	$19,503	High - June 2008	$0	790				4,003	95		713	437	155	7	1,992
5	$40,526	Low - June 2008	$45		346		261	1,600	110		1,089	734	35	2	1,835
8	$41,372	Medium - June 2008	$45					2,400	160		1,090	624	120	7	1,942
9	$40,204	Low - Oct 2008	$45		346		261	1,600	110		1,133	623	35	2	1,834
10	$40,319	Medium - Oct 2008	$45					2,600	129		1,124	513	155	7	1,936
11	$40,559	High - Oct 2008	$45	600				5,000	114		717	651	155	7	2,024
14	$39,949	High - June 2008	$45	600		466		6,287	120		711	272	155	7	2,066
17	$51,207	Medium - June 2008	$70		876			3,900	122		1,084	609	155	7	2,020
18	$49,745	Low - Oct 2008	$70		876			3,900	122		1,089	667	155	7	1,974
19	$50,102	Medium - Oct 2008	$70		876			4,100	122		1,094	610	155	7	2,009
20	$50,536	High - Oct 2008	$70		876			6,600	114	1,600	842	651	155	7	2,035
22	$49,983	High - June 2008	$70	600	876			7,200	101	1,600	616	161	155	7	2,115
24	$60,693	Medium - June 2008	$100		876			6,600	122	3,200	802	280	155	7	2,076
25	$58,838	Low - Oct 2008	$100		876			6,175	122		1,070	777	155	7	2,035
26	$59,660	Medium - Oct 2008	$100		876			6,600	122	3,200	783	311	155	7	2,042
27	$60,484	High - Oct 2008	$100		876			6,680	120	3,200	972	650	155	7	2,098
29	$57,635	High - June 2008	$100		876	466		7,200	167	3,200	575	450	155	110	2,183
46	$21,532	Medium - Oct 2008	$8, C&T	600			174	1,388	151		897	468		19	1,825
47	$20,863	Medium - Oct 2008	$8, C&T	600			174	1,344	151		892	469		29	1,822
Low Load Growth Core Cases															
4	$34,612	Low - June 2008	$45		346			300	110		269	125	35		1,801
7	$34,582	Medium - June 2008	$45		346			1,800	110		185	115	85		1,857
13	$31,076	High - June 2008	$45	600				4,800	95		71	81	155		2,038
16	$43,523	Medium - June 2008	$70		876			3,599	122		108	111	155		1,990
21	$40,517	High - June 2008	$70		876			6,202	95	1,600	124	70	155		2,058
23	$51,692	Medium - June 2008	$100		876			6,600	122	3,200	157	85	155		2,045
28	$47,806	High - June 2008	$100		876			5,800	95	3,200	150	67	155		2,036
High Load Growth Core Cases															
6	$48,140	Low - June 2008	$45				1,838	1,600	209		1,181	1,125	155	126	1,983
12	$50,146	Medium - June 2008	$45	600			888	2,299	169		1,186	1,125	155	126	2,082
15	$50,914	High - June 2008	$45	600		466	261	6,599	169	1,600	1,148	572	655	125	2,163
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth															
30	$48,541	Medium - June 2008	$45 to $179		876	466		7,000	122	3,200	743	126	155	7	2,091
31	$47,552	High - June 2008	$45 to $179		876			7,200	122	3,200	815	130	155	7	2,159
Sensitivity Case - High Cost Outcome															
33	$69,949	High - June 2008	$100	600			1,100	7,200	169		762	1,125	655	126	2,294
Sensitivity Cases - Clean Base-Load Generation Availability															
34	$40,564	Medium - June 2008	$45					3,900	152		1,109	539	85	7	1,937
35	$39,853	High - June 2008	$45	600				5,000	97		778	479	120	7	2,022
36	$51,242	Medium - June 2008	$70		876			4,200	169		1,127	762	120	110	2,046
37	$48,949	High - June 2008	$70		876			5,762	95	3,200	468	150	120	7	2,061
Sensitivity Cases - High Plant Construction Costs															
38	$41,974	Medium - June 2008	$45					2,118	151		1,114	535	85	64	1,970
39	$34,791	High - June 2008	$45	600				3,255	149		641	580	120	109	2,113
Sensitivity Case - System-wide Oregon CO2 Reduction Targets															
40	$24,761	Medium - June 2008	Hard Cap		876			2,200	124		999	1,000	85	104	1,880
Sensitivity Cases - Planning Reserve Margin, 15%															
41	$41,542	Medium - June 2008	$45				261	1,934	163		1,168	590	155	25	1,941
42	$51,420	Medium - June 2008	$70		876		261	3,600	122		1,160	679	155		2,017
43	$60,905	Medium - June 2008	$100		876			6,600	163	3,200	907	291	155	105	2,104
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)															
44	$21,249	Medium - Oct 2008	$8, C&T	600				5,673	149		948	161	155	109	1,811
45	$20,875	Medium - Oct 2008	$8, C&T	600			261	881	110		904	430	120	2	1,795
Sensitivity Case - Class 3 DSM for Peak Load Reduction															
48	$41,268	Medium - June 2008	$45					2,400	122		1,037	679	85	121	1,932

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

Wind Resource Selection

Wind resource selection varied considerably across the portfolios, ranging from no resources in one portfolio (case 1, with no CO_2 tax and low gas prices) to 7,200 MW in five portfolios (cases 11, 29, 30, 31, and 33—all based on high gas prices and a CO_2 tax of $70 or greater). For the $45 CO_2 tax core cases with medium load growth, the amount of wind capacity averaged over 3,200 MW. For the $70 and $100 CO_2 tax core cases with medium load growth, the amount of wind capacity averaged over 5,100 MW and 6,600 MW, respectively. System Optimizer found wind to be cost-effective for displacing gas generation under high gas price scenarios, reducing CO_2 taxes, and selling to markets during off-peak periods.

Regarding the timing of wind additions, the model generally started adding wind capacity early in the study period, from 2010 to 2012, with large and constant amounts included in response to high gas prices, high CO_2 tax values, or both. For these cases, the model often selected amounts up to the limit allowed in a year (500 MW prior to 2014, and 750 MW in 2014 and thereafter). In only a few of the cases was wind added after 2020, generally to help meet RPS requirements owing to less wind investment made earlier in the study period (for example, cases 2 and 5). The expiration of the renewable PTC in 2013 (case 45) was found to significantly impact the amount and timing of wind additions; no wind was added after 2012.

An important caveat to these results is that System Optimizer does not account for reliability impacts and associated costs from adding large amounts of wind to the system.

Gas Resource Selection

Intercooled aeroderivative (IC aero) SCCT plants were the most common gas resource included in the portfolios, occurring in cases having low gas prices combined with either the $0 or $45 CO_2 tax, or medium gas prices combined with no CO_2 tax. The SCCT plant (261 MW) was always selected in 2016.

Combined-cycle gas plants were selected infrequently, only appearing in three scenario situations: high load growth and either the low or medium gas price assumptions (cases 6 and 12), and the high-cost bookend scenario (case 33). The model chose only west-side CCCT units with a 2015 in-service date.

Class 1 Demand-side Management Resource Selection

The model selected a small amount of Class 1 DSM capacity, 2 to 7 MW, for most of the portfolios, favoring Idaho dispatchable irrigation over other programs. This capacity was added most commonly between 2016 and 2018, with the earliest additions in 2013 for portfolios with no wind capacity chosen in the early years. Additions reached over 100 MW for high load growth scenarios, while no capacity was added in any of the portfolios developed with the low load growth scenario. Of the core cases with medium load growth, only two cases—numbers 1 and 29—included more than 100 MW. For case 1, which was based on no CO_2 tax and low gas prices, Class 1 DSM appears to substitute for renewables capacity added in most other portfolios. For case 29, the selection of Class 1 DSM is driven by low utilization of gas plants stemming from the combination of the $100 CO_2 tax and high gas prices.

Class 2 Demand-side Management Resource Selection

The model selected a sizable amount of Class 2 DSM in all portfolios by 2028, ranging from 1,537 MW to 2,183 MW, and adding this DSM on a relatively constant basis for every year of the simulation period. For the medium load growth portfolios, the average amount included was 1,970 MW. The variation of the DSM among these portfolios, as measured by the standard deviation, was only about 130 MW.

Supercritical Pulverized Coal Resource Selection

The model selected supercritical coal plants in response to the following set of conditions:

- No CO_2 tax combined with medium or high gas prices (cases 2 and 3)
- The \$8 CO_2 cap-and-trade allowance price (cases 44 and 45, and business plan reference cases 46 and 47)
- The \$45 CO_2 tax combined with high gas prices (cases 11, 14, 35, and 39)
- The \$45 CO_2 tax with low load growth, combined with high gas prices (case 13)
- The \$45 CO_2 tax with high load growth, combined with either medium or high gas prices (cases 12 and 15)
- The \$70 CO_2 tax combined with high gas prices (case 22)

Only one coal plant was included in these portfolios. The plant was always selected in 2018, except for the two business plan reference cases, where it was added in 2019.

The combination of scenario inputs for which supercritical coal plants were chosen indicates that determining a CO_2 cost trigger point at which coal plants are no longer cost-effective has limited value without considering the impact of gas prices.

Geothermal Resource Selection

Geothermal was included in a large majority of the case portfolios, and generally selected in 2013—the first year of availability. The Blundell 3 project appeared in all portfolios where this resource was configured as an option, except for case 1 (defined with no CO_2 tax and low gas prices). The green-field projects in both the east and west were not cost-effective in a number of low load growth scenarios, but frequently appeared in the portfolios developed with all other combinations of scenario input values.

An interesting result of enforcing the high renewable portfolio standard requirement for case 44 was that the geothermal resources were deferred from their typical 2013 in-service dates: the Blundell 3 project was added in 2015, while the east and west green-field resources were added in 2020 and 2025, respectively. The model followed a similar deferral strategy for case 45, where the production tax credit expired in 2013. For this portfolio, Blundell 3 was deferred to 2016, while the west green-field resource was deferred to 2023.

Nuclear Resource Selection

Nuclear plants become cost-effective resource alternatives under high gas price and CO_2 tax scenarios; they are also always selected in 2025, the earliest in-service year. A 1,600 MW unit was chosen with a \$70 CO_2 tax combined with high gas prices. The model selected a 3,200 MW unit given a \$100 CO_2 tax and medium or high gas prices. There is no clear preference for nuclear resources given the level of load growth assumed.

Clean Coal Resource Selection

Clean coal technologies appear under the \$45 CO_2 tax in limited circumstances; only in combination with low gas and electricity prices. Under medium gas price scenarios, renewables, energy efficiency, and distributed generation substitute for a single pulverized coal CCS retrofit project. Only under the highest gas/electricity prices (June 2008 forward price curve) does IGCC become cost-effective with a \$45 CO_2 tax.

Multiple pulverized coal CCS retrofit units are added in all portfolios specified with the \$70 and \$100 CO_2 tax. IGCC capacity is only added under the June 2008 high gas price scenario.

Short-term Market Purchase Selection

Reliance on front office transactions varies substantially among the portfolios. They are utilized more heavily under the low and medium gas price scenarios. In contrast, portfolios with large quantities of wind or base-load coal tend to rely less on them. The portfolios do not exhibit a correlation between the CO_2 tax level and the amount of front office transactions.

Distributed Generation Selection

Distributed generation resources—CHP and standby generation—was selected in all the portfolios, and ranged from 95 MW in case 3 (medium load growth, no CO_2 tax, and high June 2008 gas price scenario) to 209 MW in case 6 (high load growth, \$45 CO_2 tax, and low June 2008 gas price scenario).

Standby generation, biomass CHP, and the Kern River Recovered Energy Generation projects were most commonly selected. Standby generation and biomass always appeared in the first year of availability (2009), while the Kern River REG units appeared between 2011 and 2015. The low biomass fuel price assumed for the CHP resource explains why it appears in all the portfolios. Quantities were typically added in constant amounts each year until 2018. Kern River REG units were not selected under low load growth scenarios, or a combination of the \$45 CO_2 tax and low gas price scenarios. Additions of reciprocating engine CHP were less common, and are sensitive to the gas prices assumed. System optimizer generally started adding this type of CHP resource in the 2012-2013 time frame, with constant amounts (typically 1 or 2 MW) appearing in each year.

There is no single factor that accounts for the amount of distributed generation capacity selected; rather, a combination of low or medium gas price scenarios and higher CO_2 tax levels appear associated with larger quantities added.

Emerging Technology Resource Selection

Emerging technologies—solar, energy storage, and fuel cells—were rarely selected by the model, and appear in no more than one portfolio. The portfolio for case 15 includes 500 MW of solar thermal with natural gas backup (250 MW in 2014 and 2015), added in response to a \$45 CO_2 tax and high load growth and gas prices. Compressed air energy storage and battery storage appear in case 12 as a response to a \$45 CO_2 tax combined with high load growth and medium gas prices. (CAES air compression is fueled by simple-cycle combustion turbines). These technologies are added late in the simulation period, after 2025. Finally, fuel cells appear in the portfolio for case 6 in 2016 (40 MW in the east side), developed with high load growth, low gas prices, and the \$45 CO_2 tax.

Transmission Option Selection

PacifiCorp included three transmission resource options in System Optimizer:

- An Energy Gateway West expansion totaling 750 MW (Path C to West Main) available in 2015
- A Walla Walla to West Main transmission project available beginning in 2014, with capacity options of 200 MW and 400 MW

System Optimizer did not these transmission options in any of the portfolios.

Incremental Resource Selection under Alternative Load Growth Scenarios

Observations concerning the incremental resources selected as load growth increases are as follows:

\$45/ton CO_2 Tax and Low Gas Prices

- Moving from low to medium load growth, System Optimizer chose front office transactions as the dominant resource for meeting load. Mead and Mona FOT were relied on heavily beginning in 2013 and 2017, respectively. Additionally, the model added an IC aero SCCT in 2016 (261 MW), a significant amount of east-side wind (750 MW by 2018, and another 450 MW by 2021), and a small quantity of east-side Class 2 DSM.
- Moving from medium to high load growth, the model added a diverse mix of resource types. Incremental resources included: combined-cycle (1,100 MW by 2018 and another CCCT plant added in 2020); 123 MW of Class 1 DSM by 2014; 131 MW of Class 2 DSM by 2028, 40 MW of fuel cell capacity by 2016, 50 MW of utility-scale biomass by 2016, and west-side front office transactions in the out-years. No incremental wind capacity was added.

\$45/ton CO_2 Tax and Medium Gas Prices

- Moving from low to medium load growth, System Optimizer relied mostly on front office transactions and wind to serve the higher loads. The incremental resource mix included 600 MW of wind, CHP, distributed standby generation, west-side geothermal, and Class 2 DSM.
- Moving from medium to high load growth, the optimal resource mix shifted to conventional thermal resources and fewer wind additions. A coal plant and IC aero SCCT plant were added in the east during the first 10 years of the study period, with a consequent reduction in east-side wind (about 500 MW), while a combined cycle plant was added in the west. A significant amount of Class 1 DSM was also added (118 MW), along with Class 2 DSM.

\$45/ton CO_2 Tax and High Gas Prices

- Moving from low to medium load growth, the model chose wind and, despite the high gas prices, front office transactions, as the primary resources needed to serve load. By 2021, the model added about 1,500 MW of wind. From 2017 through 2028, the model selected Mead front office transactions, averaging 460 MW per year. An IGCC plant was also added in 2025.

- Moving from medium to high load growth, System Optimizer added 250 MW of solar in both 2014 and 2015, and added an east-side IC Aero SCCT in 2016. Other resource additions include: front office transactions (Mead and Mid-Columbia); 84 MW of Class 1 DSM by 2020; 96 MW of Class 2 DSM by 2025; over 300 MW of wind (400 MW added in the east—accelerated by two years—along with a 100 MW reduction in the west); 47 MW of distributed standby generation, and; a 1,600 MW nuclear unit in 2015.

$70/ton CO_2 Tax and Low Gas Prices

Moving from low to medium load growth, the dominant resources for meeting the higher loads are wind and front office transactions. The model added 300 MW of wind by 2018. Selection of all available Mead and Mona front office transactions began in 2018, while use of Mid-Columbia transactions ramped up from 2013 to full utilization by 2020 and beyond. Additional Class 2 DSM was also selected, reaching 86 MW by 2023.

$70/ton CO_2 Tax and Medium Gas Prices

Moving from low to medium load growth, the model chose a conventional pulverized coal plant in 2018 and additional wind. On the east-side, it added 911 MW of wind from 2018 through 2020, and deferred west-wide wind additions to 2019 and 2020. This wind resource timing suggests that the model's strategy was to dilute the coal plant's CO_2 tax impact by adding wind.

$100/ton CO_2 Tax and Medium Gas Prices

Moving from low to medium load growth, System Optimizer relied on wind and front office transactions to address the higher load growth. Unlike the $70/ton scenario, the model did not find it cost-effective to add a conventional coal resource and offset it with wind or other renewables. In the out-years, the portfolio relied on both front office transactions (primarily Mid-Columbia) and growth resources to meet load.

$100/ton CO_2 Tax and High Gas Prices

Moving from low to medium load growth, System Optimizer depended heavily on wind resources to meet load, adding 1,351 MW in two years: 2019 and 2020. Additionally, the model increased reliance on front office transactions, although this reliance was temporary in the east side (2018 through 2020). The model also chose addition DSM, including 110 MW of Class 1 DSM and 147 MW of Class 2 DSM.

Thermal Resource Utilization

Table 8.3 shows for gas and coal resources the average annual capacity factors for each portfolio, reflecting both existing and new resources. The capacity factors are reported for the entire simulation period, as well as for the following periods: 2009-2012 (capturing plant operations before a CO_2 tax goes into effect), 2013-2020, and 2021-2028.

The impact of the CO_2 tax on plant dispatch is shown by comparing the capacity factors for the 2009-2012 and 2013-2020 periods for the various gas price scenarios. Low gas prices cause the tax burden to fall on the coal plants, which realize a typical 10-percentage-point utilization decrease under a \$45 CO_2 tax, a 20-percentage-point utilization decrease under a \$70 CO_2 tax, and a 50 percentage point decrease under the \$100 CO_2 tax. With a \$100 CO_2 tax, a number of coal plants become uneconomic to operate, dispatching with a capacity factor in the single digits.

As gas prices increase in combination with a CO_2 tax, the tax burden shifts to the gas plants, which see a large drop-off in utilization. Under a \$100 CO_2 tax and high gas price scenarios, coal plant utilization drops by 10 to 16 percentage points.

Table 8.3 – Average Annual Thermal Resource Capacity Factors by Portfolio

			Gas Plant Capacity Factors (%)				Coal Plant Capacity Factors (%)			
Case	**Gas Price Scenario / FPC**	**CO2 Price**	**Average, 2009-2012**	**Average, 2013-2020**	**Average, 2021-2028**	**Average, 2009-2028**	**Average, 2009-2012**	**Average, 2013-2020**	**Average, 2021-2028**	**Average, 2009-2028**
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)										
1	Low - June 2008	$0	33	39	61	47	86	87	88	87
2	Medium - June 2008	$0	30	30	40	34	86	87	88	87
3	High - June 2008	$0	34	17	16	20	86	87	88	87
5	Low - June 2008	$45	35	40	59	46	86	73	71	75
8	Medium - June 2008	$45	31	28	46	36	86	86	86	86
9	Low - Oct 2008	$45	42	40	64	50	86	76	73	77
10	Medium - Oct 2008	$45	57	34	57	48	85	86	87	86
11	High - Oct 2008	$45	38	14	18	21	86	86	85	86
14	High - June 2008	$45	25	11	13	15	86	86	87	86
17	Medium - June 2008	$70	30	29	48	37	86	72	68	73
18	Low - Oct 2008	$70	42	42	75	55	86	54	46	57
19	Medium - Oct 2008	$70	57	33	62	49	85	71	64	71
20	High - Oct 2008	$70	37	12	14	18	86	82	77	81
22	High - June 2008	$70	25	10	11	14	86	84	81	83
24	Medium - June 2008	$100	28	31	48	37	86	52	37	53
25	Low - Oct 2008	$100	41	43	69	53	86	34	29	42
26	Medium - Oct 2008	$100	56	36	57	48	85	49	37	51
27	High - Oct 2008	$100	36	13	10	16	86	71	60	69
29	High - June 2008	$100	20	5	6	8	86	76	57	71
46	Medium - Oct 2008	$8, C&T	35	35	58	44	86	87	88	87
47	Medium - Oct 2008	$8, C&T	35	35	58	44	86	87	88	87
Low Load Growth Core Cases										
4	Low - June 2008	$45	34	39	63	48	86	71	68	73
7	Medium - June 2008	$45	30	24	38	31	86	86	86	86
13	High - June 2008	$45	25	9	10	13	86	84	83	84
16	Medium - June 2008	$70	29	24	41	32	86	70	64	70
21	High - June 2008	$70	25	8	8	12	86	83	78	82
23	Medium - June 2008	$100	27	28	40	33	86	48	32	49
28	High - June 2008	$100	20	4	3	7	86	72	49	65
High Load Growth Core Cases										
6	Low - June 2008	$45	36	40	55	45	86	73	71	75
12	Medium - June 2008	$45	32	27	42	34	86	86	87	86
15	High - June 2008	$45	26	14	16	17	86	86	87	86
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth										
30	Medium - June 2008	$45 to $179	31	31	58	42	86	83	53	72
31	High - June 2008	$45 to $179	28	14	21	19	86	86	66	78
Sensitivity Case - High Cost Outcome										
33	High - June 2008	$100	24	8	9	11	85	85	86	85
Sensitivity Cases - Clean Base-Load Generation Availability										
34	Medium - June 2008	$45	32	27	44	35	86	85	86	86
35	High - June 2008	$45	30	17	16	19	86	86	83	85
36	Medium - June 2008	$70	19	29	48	34	86	73	67	73
37	High - June 2008	$70	25	10	6	12	86	82	73	79
Sensitivity Cases - High Plant Construction Costs										
38	Medium - June 2008	$45	33	32	48	38	86	87	88	87
39	High - June 2008	$45	24	10	11	13	85	80	84	82
Sensitivity Case - System-wide Oregon CO2 Reduction Targets										
40	Medium - June 2008	Hard Cap	30	11	10	15	86	77	67	75
Sensitivity Cases - Planning Reserve Margin, 15%										
41	Medium - June 2008	$45	31	26	41	33	86	86	86	86
42	Medium - June 2008	$70	29	27	43	34	86	72	68	73
43	Medium - June 2008	$100	28	31	48	37	86	52	36	52
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)										
44	Medium - Oct 2008	$8, C&T	35	33	49	40	86	87	88	87
45	Medium - Oct 2008	$8, C&T	34	33	58	43	85	86	88	87
Sensitivity Case - Class 3 DSM for Peak Load Reduction										
48	Medium - June 2008	$45	32	29	47	37	86	86	86	86

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

Sensitivity Case Results

CO2 Tax Real Cost Escalation and Demand Response

Cases 30 and 31 were designed to test a real escalating CO_2 tax and assumed decrease in load growth attributable to the price response. The CO_2 tax begins in 2013 and is increased at a real straight-line escalation rate resulting in $7.86/ton increases per year starting in 2014. Load growth is maintained at a medium level through 2020, after which the growth converts to a low forecast for the remainder of the simulation period.

For the two cases, all factors were held constant with the exception of the gas price forecast used: case 30 was based on the June 2008 medium gas price while case 31 was based on the June 2008 high gas price forecast. The case 30 portfolio included 5,498 MW of wind added by 2028, a nuclear plant in 2025, and four carbon capture and sequestration plants in 2025, including an IGCC resource. The case 31 portfolio included more wind and front office transactions, but excluded the IGCC resource.

The PVRR for case 31 was $989 million lower than case 30, an unintuitive result. Several factors contributed to this PVRR difference:

- The 466 MW Utah IGCC with CCS unit added in the case 30 portfolio was not included in case 31. Instead, higher on-peak spot purchases and DSM programs costs were incurred in case 31.
- Case 31 included 750 MW more wind than case 30 in the first ten years. As a result of the additional wind, existing station fuel costs in case 31 were $1.1 billion lower than in case 30.
- While the capital costs for case 31 were $2.4 billion higher than in case 30, the difference was offset by higher spot market sales in case 31.

Normally the System Optimizer model will build to the 12% planning reserve margin level; however, it may exceed that if it is economic to add extra capacity and sell excess energy to the market. For example, in cases 30 and 31, the model added resources in excess of the planning reserve margin in 2025 through 2028 with the addition of a 3,200 MW nuclear plant. Significant excess energy is sold to market, contributing to $27.6 and $30.0 billion PVRR reductions for cases 30 and 31, respectively

Early Clean Base-load Resource Availability

Cases 34 through 37 were designed to test early availability of clean base-load generation resources by allowing System Optimizer to select such resources as early as 2020 rather than 2025 as specified for all other case definitions. Cases 34 and 35 were specified with a $45/ton CO_2 tax and varying gas price forecasts (medium and high June 2008), while cases 36 and 37 were based on a $70 CO_2 tax with the same gas price forecasts.

For cases 34 and 35, no clean base-load technology was selected; however, the high gas price forecast used in case 35 caused the model to select about 1,000 MW of additional wind in the west and a 600 MW pulverized coal plant in Utah. Case 34 favored front office transactions.

For cases 36 and 37 (both with the \$70 CO_2 tax), three clean coal resources were selected in 2020. For case 37, the model also selected a 3,200 MW nuclear station in 2020 as an alternative to market purchases in the out years. The PVRR for case 37 is about \$2.3 billion lower than case 36, and this cost relationship exists between cases 34 and 35 as well. As indicated above, the cost difference is attributable to the model selling excess energy to the market.

High Construction Costs

For cases 38 and 39, resource construction costs were uniformly increased by 20 percent. Both were based on a \$45 CO_2 tax, medium load growth, and medium and high gas price forecasts, respectively.

Comparing case 38 to case 8 (which used the same input assumptions except for construction costs) indicates that the uniform percentage cost increase caused the model to select additional DSM programs along with dispatching existing units more often. Similarly, a comparison between cases 39 and 14 indicate that the construction cost increase, combined with a higher gas price forecast, caused the model to build about 3,000 MW less wind in case 39 than for case 14. The reduced wind build in case 39 was a major contributor to the lower PVRR relative to that for case 14 (a \$5.16 billion difference). In addition, the Utah IGCC unit picked in case 14 was not chosen in case 39. For case 39, the model preferred to buy from the market and relied more heavily on growth resources in the out years. In case 39, units were not dispatched as often as in case 14 and there was consequently less power to sell to the market.

Carbon Dioxide Emissions Hard Cap

Case 40 was designed to determine the optimal resource mix given a system-wide CO_2 emissions hard cap patterned after the Oregon CO_2 reduction targets from House Bill 3543 (10 percent below 1990 levels by 2020, and at least 75% below 1990 levels by 2050). The specific allowances per year reflected in the System Optimizer model are reported in Table 8.4. The cap is assumed to go into effect beginning in 2013. With these system emission constraints in place, the model optimizes the resource mix such that the system-wide average emissions stay at or below the annual caps.

Table 8.4 – Hard Cap CO_2 Emission Allowances

Year	Hard Cap CO2 Allowances (Million Short Tons)
2009	53.484
2010	53.484
2011	55.192
2012	56.077
2013	54.244
2014	52.412
2015	50.579
2016	48.746
2017	46.913
2018	45.081
2019	43.248
2020	41.415
2021	40.418
2022	39.421
2023	38.424

Year	Hard Cap CO2 Allowances (Million Short Tons)
2024	37.427
2025	36.430
2026	35.433
2027	34.436
2028	33.439

For this sensitivity study, front office transactions and growth resources were assigned a proxy CO_2 emission rate. The rate is that for a Utah combined-cycle gas plant (F type 2x1), reflecting a presumed long term reduction in the WECC CO_2 footprint attributable to the penetration of gas, wind and other renewable resources in the resource stack. Additionally, the June 2008 $0 CO_2 tax forward price forecasts were used to ensure that the model's capacity expansion solution was constrained by the hard cap only, and not impacted by CO_2 costs reflected in market prices.

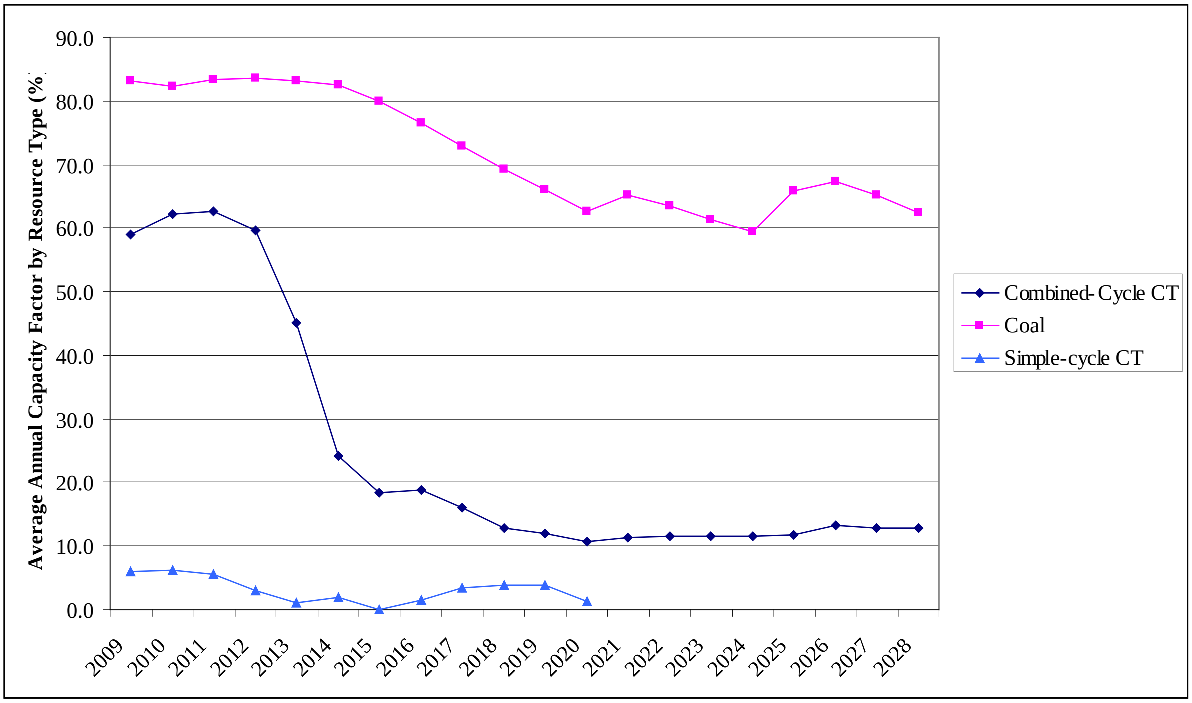
Table 8.5 compares the total emissions generated in case 40 to the three core cases with medium load, medium gas forecasts (Case 8, 17, and 24). The results indicate that the hard cap portfolio is most comparable to the $70 CO_2 tax portfolio, having total cumulative emissions of 896 and 931 million tons, respectively.

Table 8.5 – Portfolio Comparison, System Optimizer Total CO_2 Emissions by Year

Year	CO2 emissions (Millions Short Tons)			
	Case 40	Case 8	Case 17	Case 24
	System Hard Cap	$45/ton CO2 tax	$70/ton CO2 Tax	$100/ton CO2 Tax
2009	54.0	54.5	54.4	54.4
2010	53.7	54.0	53.8	53.6
2011	54.5	54.1	54.0	53.6
2012	56.1	54.2	53.6	52.5
2013	54.2	54.1	51.5	46.3
2014	52.4	53.4	49.3	43.9
2015	50.6	54.3	47.8	38.3
2016	48.7	54.2	44.5	33.7
2017	46.9	55.3	47.6	35.7
2018	45.1	55.3	50.0	37.7
2019	43.2	55.7	50.5	37.7
2020	41.4	55.6	50.9	37.9
2021	40.4	54.1	50.0	37.6
2022	39.4	54.1	49.2	36.3
2023	38.4	54.0	47.9	32.6
2024	37.4	54.0	45.8	27.1
2025	36.4	53.6	36.2	12.3
2026	35.4	52.7	33.0	11.9
2027	34.4	52.3	30.8	11.3
2028	33.4	51.9	29.8	10.8
Cumulative Total	896.4	1081.3	930.6	705.4

With the combination of medium June 2008 market prices and the hard cap, a significant reduction in combined-cycle gas plant capacity factors happens from 2013 through 2015, followed by a gradual decrease through 2020. Figure 8.1 compares the average annual capacity factors for combined-cycle, coal, and simple-cycle combustion turbine resources reflected in the model. Capacity factors for certain coal plants begin to drop off in 2015, while others are unaffected, reflecting the relative dispatch cost differences among the plants. As noted earlier in the chapter, the impact of CO_2 costs on plant dispatch cannot be assessed in isolation from fuel prices; utilization of thermal resource types in response to CO_2 costs will vary considerably based on the fuel price forecasts used for the simulations.

Figure 8.1 – Average Annual Capacity Factors by Resource Type, CO_2 Hard Cap Portfolio



A number of current IRP model limitations come into play for analyzing a hard cap scenario. First, the System Optimizer model does not allow emission rates to be assigned to spot market balancing transactions. This limitation is being addressed in an enhanced version of the model being developed for PacifiCorp by the model vendor. Second, the Planning and Risk model is limited in that hard caps cannot be directly enforced. To simulate the effect of a hard cap, the shadow cost for the last ton of incremental emissions calculated from System Optimizer can be entered into the Planning and Risk model. PacifiCorp is in the process of experimenting and validating this work-around approach. The test simulation resulted in annual CO_2 emissions that were consistently below the hard cap. The stochastic costs results for the test simulation are as follows: mean PVRR of $41.0 billion, upper-tail mean PVRR of $76.4 billion, and production cost standard deviation of $11.7 billion.

Alternative Renewable Policy Assumptions

Case 44 is designed with a System Optimizer constraint that imposes a system-wide renewable generation requirement that reaches 25 percent of system load by 2028. Case 44 parallels case 8 in terms of other input assumptions; i.e., an \$8 CO_2 tax and medium June 2008 gas and electricity prices.

In order to satisfy the higher RPS requirement, the model selected a large amount of wind and some geothermal resources, especially in the mid and later years of the simulation period. With nearly 6,000 MW of wind resources built, this scenario attributes a relatively small PVRR to sales of clean energy to markets.[47]

The second alternative renewable policy scenario was established to determine the best resource mix without the renewable production tax credit after 2012. Case 45 was created from case 44 with the base case RPS requirement, but the costs of resources qualifying for the PTC were adjusted to remove the incentive after 2012. Without the PTC, the model selected:

- No wind resources after 2012
- A west geothermal resource in 2023
- An IC Aero SCCT in 2016 instead of wind resources
- More growth resource capacity in the out years

STOCHASTIC SIMULATION RESULTS - CANDIDATE PORTFOLIOS

This section presents stochastic cost, stochastic supply reliability risk, and capital cost performance results for the 21 portfolios that constitute the group from which the preferred portfolio was selected. For the stochastic cost measures, results are first shown for the three individual CO_2 tax simulations, along with the straight average across the CO_2 tax results. The section concludes with tables that show the stochastic cost results as probability-weighted values. These values reflect \$5/ton increments of the expected value (EV) CO_2 tax, ranging from \$20/ton to \$70/ton.

Stochastic Mean PVRR

Table 8.6 reports the stochastic mean PVRR for each of the candidate portfolios by CO_2 tax level, along with average values and associated rankings. Cases 8, 5, and 9 rank the highest based on the average of the CO2 tax results.

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[47] The cost results presume a regulatory world with both a \$45/ton CO_2 tax and an aggressive RPS requirement. In this situation, the markets would be flooded with excess clean energy, driving market prices down. This dynamic is not captured in the scenario. Also, the reliability impacts and costs of such large amounts of wind being added to the system are not factored into the IRP simulations.

Table 8.6 – Stochastic Mean PVRR by Candidate Portfolio

	CO2 Tax Level, Million Dollars (2009$)				
Case	**$0/ton**	**$45/ton**	**$100/ton**	**Average**	**Rank**
1	21,873	39,893	61,299	41,022	10
2	21,642	39,542	60,098	40,427	4
3	24,844	40,745	57,781	41,123	11
5	22,417	39,289	58,700	40,136	2
8	23,092	39,244	57,311	39,882	1
9	22,532	39,398	58,800	40,244	3
10	23,723	39,872	58,198	40,598	6
11	25,664	41,035	57,496	41,398	12
14	27,620	42,481	57,954	42,685	16
17	25,267	40,134	56,369	40,590	5
18	25,092	40,185	56,822	40,700	7
19	25,600	40,513	56,870	40,994	9
20	28,412	42,127	56,620	42,386	15
22	29,751	43,576	57,813	43,713	20
24	30,393	43,496	57,094	43,661	19
25	27,178	41,317	56,419	41,638	13
26	30,056	43,417	57,485	43,653	18
27	30,367	43,477	57,105	43,650	17
29	32,601	45,626	59,042	45,757	21
46	23,336	40,975	61,146	41,819	14
47	22,345	40,058	60,378	40,927	8

Table 8.7 reports the incremental mean PVRR associated with imposing the $45/ton and $100/ton CO_2 taxes, as well as the average cost for the two tax levels. Table 8.8 reports the net power cost (variable cost less market sales revenue) and fixed cost by portfolio for the three CO_2 tax simulations.

Table 8.7 – Incremental Mean PVRR by CO_2 Tax Level

	Incremental Mean PVRR (Million $)		
Case	**$45/ton**	**$100/ton**	**Average**
1	18,019	39,426	28,723
2	17,900	38,456	28,178
3	15,901	32,937	24,419
5	16,872	36,284	26,578
8	16,152	34,219	25,186
9	16,866	36,268	26,567
10	16,149	34,476	25,312
11	15,371	31,831	23,601
14	14,861	30,334	22,597
17	14,867	31,102	22,984
18	15,093	31,730	23,411
19	14,913	31,270	23,092
20	13,715	28,208	20,962
22	13,825	28,062	20,943

Case	Incremental Mean PVRR (Million $)		
	$45/ton	$100/ton	Average
24	13,103	26,700	19,902
25	14,139	29,241	21,690
26	13,361	27,429	20,395
27	13,110	26,738	19,924
29	13,025	26,440	19,733
46	17,639	37,811	27,725
47	17,713	38,032	27,873

Table 8.8 – PVRR Net Power Costs and Fixed Costs by CO_2 Tax Level

Case	$0/ton CO2 Tax				$45/ton CO2 Tax				$100/ton CO2 Tax			
	Net Power Cost (Bil$)	Rank	Fixed Cost (Bil$)	Rank	Net Power Cost (Bil$)	Rank	Fixed Cost (Bil$)	Rank	Net Power Cost (Bil$)	Rank	Fixed Cost (Bil$)	Rank
1	20.0	21	1.8	1	38.1	21	1.8	1	59.5	21	1.8	1
2	18.3	18	3.4	2	36.2	20	3.4	2	56.7	20	3.4	2
3	14.1	9	10.7	12	30.0	10	10.7	12	47.1	11	10.7	12
5	18.3	20	4.1	3	35.2	17	4.1	3	54.6	17	4.1	3
8	16.8	14	6.3	7	33.0	14	6.3	7	51.0	14	6.3	7
9	18.3	19	4.2	5	35.2	16	4.2	5	54.6	16	4.2	5
10	17.4	15	6.4	8	33.5	15	6.4	8	51.8	15	6.4	8
11	13.9	8	11.8	13	29.2	9	11.8	13	45.7	9	11.8	13
14	12.7	5	14.9	15	27.6	7	14.9	15	43.0	7	14.9	15
17	15.7	11	9.6	10	30.5	11	9.6	10	46.8	10	9.6	10
18	16.1	13	9.0	9	31.2	13	9.0	9	47.8	13	9.0	9
19	15.8	12	9.8	11	30.7	12	9.8	11	47.1	12	9.8	11
20	13.2	7	15.2	16	26.9	6	15.2	16	41.4	6	15.2	16
22	12.1	1	17.6	18	25.9	4	17.6	18	40.2	4	17.6	18
24	12.4	4	18.0	20	25.5	3	18.0	20	39.1	2	18.0	20
25	14.1	10	13.0	14	28.3	8	13.0	14	43.4	8	13.0	14
26	13.1	6	17.0	17	26.4	5	17.0	17	40.5	5	17.0	17
27	12.4	3	18.0	19	25.5	2	18.0	19	39.1	3	18.0	19
29	12.2	2	20.4	21	25.3	1	20.4	21	38.7	1	20.4	21
46	17.9	16	5.4	6	35.6	18	5.4	6	55.7	18	5.4	6
47	18.2	17	4.1	4	35.9	19	4.1	4	56.2	19	4.1	4

Risk-adjusted PVRR

As discussed in Chapter 7, risk-adjusted PVRR is calculated as the stochastic mean PVRR plus five percent of the 95th percentile PVRR, with the latter term representing a cost premium reflecting the tail risk for the portfolio. This measure constitutes 45 percent of the overall composite portfolio preference score for each candidate portfolio.

Table 8.9 reports the risk-adjusted PVRR values for each of the portfolios by CO_2 tax level, along with average values and associated rankings. Cases 8, 5, and 9 rank the highest in line with the stochastic mean PVRR values reported in Table 8.3. Figure 8.2 shows the range of risk-adjusted PVRRs for each portfolio by CO_2 tax level, matched up with the amount of incremental wind capacity included. It is apparent from the chart that the variation in risk-adjusted PVRR across the CO_2 tax levels generally decreases as the amount of portfolio wind capacity increases.

Figures 8.3 through 8.7 show capacity by resource type for each portfolio, ranked by risk-adjusted PVRR averaged across the CO_2 tax simulations. The resource types include wind, energy efficiency, average annual front office transactions, clean base load coal, and IC aero SCCT resources. These charts indicate the correlation between the amount of primary resource type added to the portfolios and the risk-adjusted cost. As can be seen from Figure 8.3, the positive correlation between risk-adjusted PVRR and amount of wind capacity added is clearly evident. Similarly the negative correlation between risk-adjusted PVRR and the volume of front office transactions is evident in Figure 8.4.

Table 8.9 – Risk-adjusted PVRR by Portfolio

Case	CO2 Tax Level, Million Dollars (2009$)			Average	Rank
	$0/Ton	$45/Ton	$100/Ton		
1	23,992	43,093	66,090	44,392	12
2	23,506	42,492	64,586	43,528	4
3	26,610	43,555	61,952	44,039	9
5	24,365	42,270	63,154	43,263	2
8	24,942	42,138	61,628	42,903	1
9	24,489	42,387	63,261	43,379	3
10	25,676	42,815	62,585	43,692	6
11	27,472	43,856	61,646	44,324	11
14	29,422	45,340	62,046	45,603	16
17	27,173	43,021	60,574	43,589	5
18	27,009	43,093	61,077	43,726	7
19	27,533	43,427	61,111	44,024	8
20	30,314	44,957	60,666	45,312	15
22	31,599	46,442	61,886	46,642	20
24	32,292	46,363	61,088	46,581	18
25	29,107	44,193	60,544	44,615	13
26	31,986	46,290	61,528	46,602	19
27	32,251	46,338	61,087	46,559	17
29	34,596	48,571	63,133	48,767	21
46	25,255	43,973	65,681	44,970	14
47	24,233	43,022	64,885	44,047	10

Figure 8.2 – Risk-adjusted PVRR Range and Wind Nameplate Capacity by Portfolio

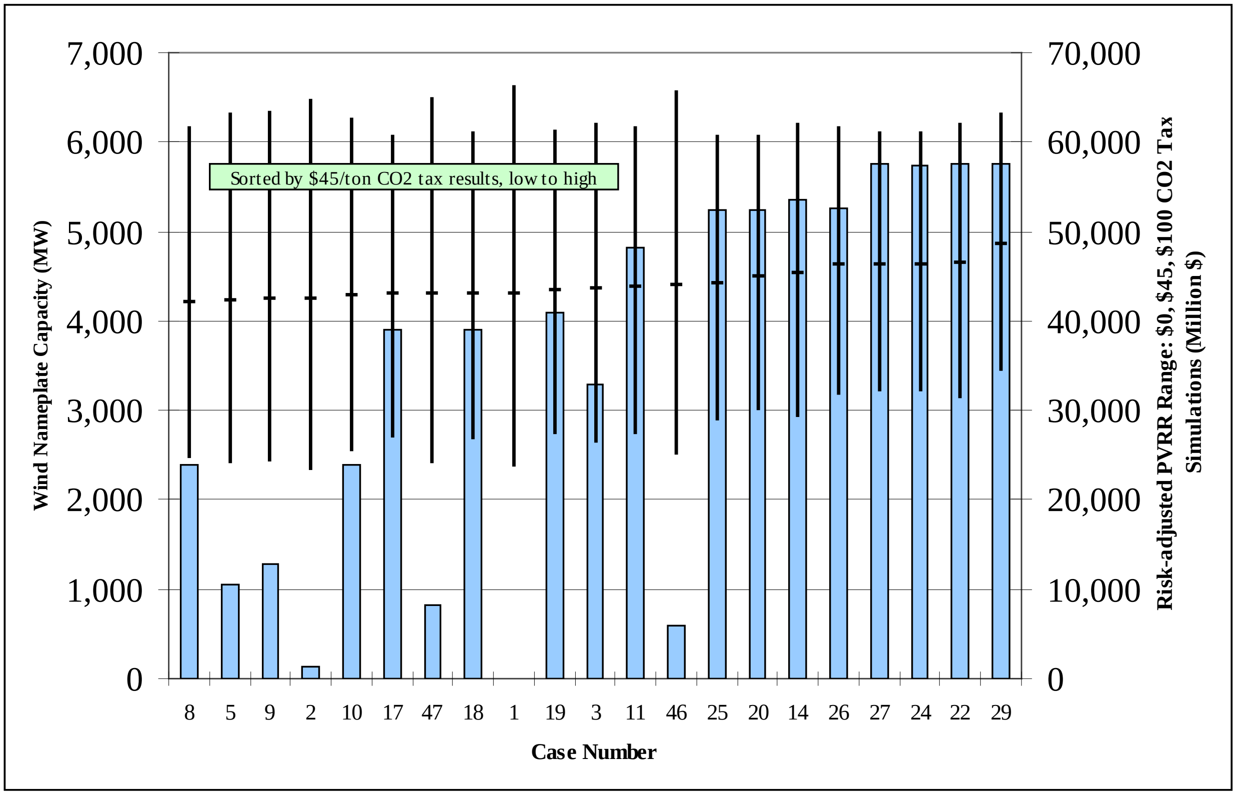


Figure 8.3 – Wind Capacity for Portfolios Ranked by Risk-adjusted PVRR

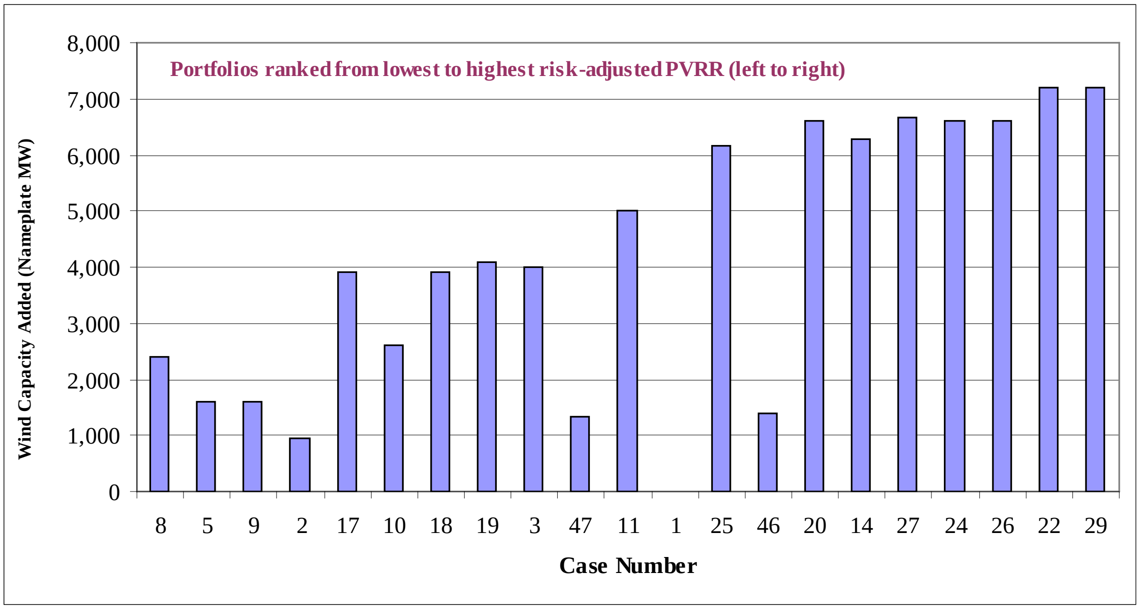


Figure 8.4 – Energy Efficiency Capacity for Portfolios Ranked by Risk-adjusted PVRR

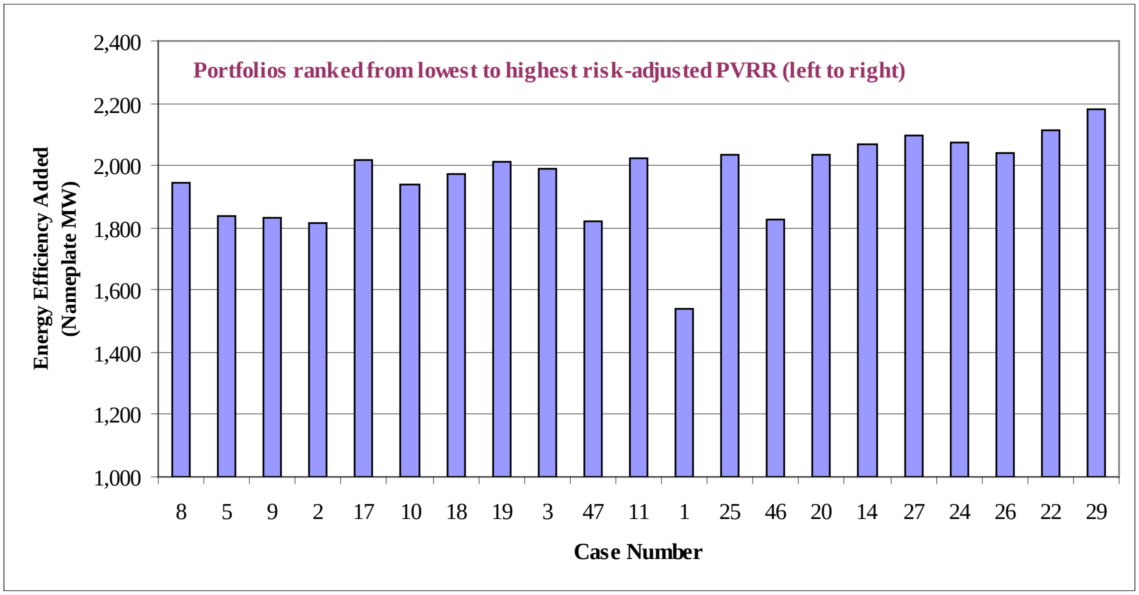


Figure 8.5 – Annual Average Front Office Transaction Capacity for Portfolios Ranked by Risk-adjusted PVRR

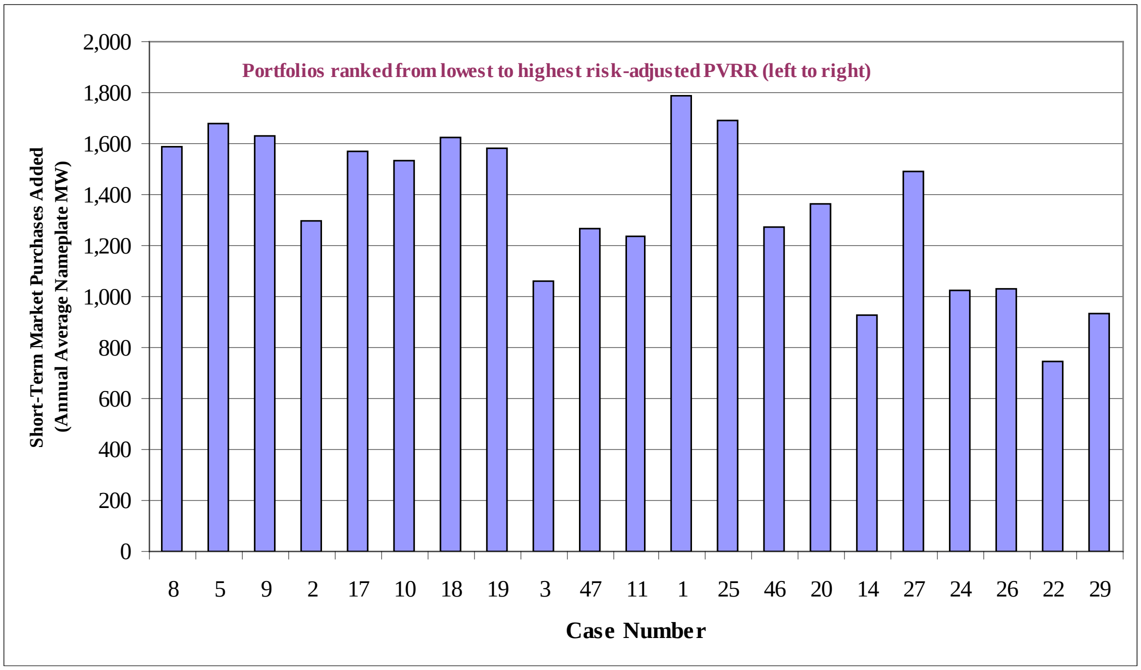


Figure 8.6 – Clean Base Load Coal Capacity for Portfolios Ranked by Risk-adjusted PVRR

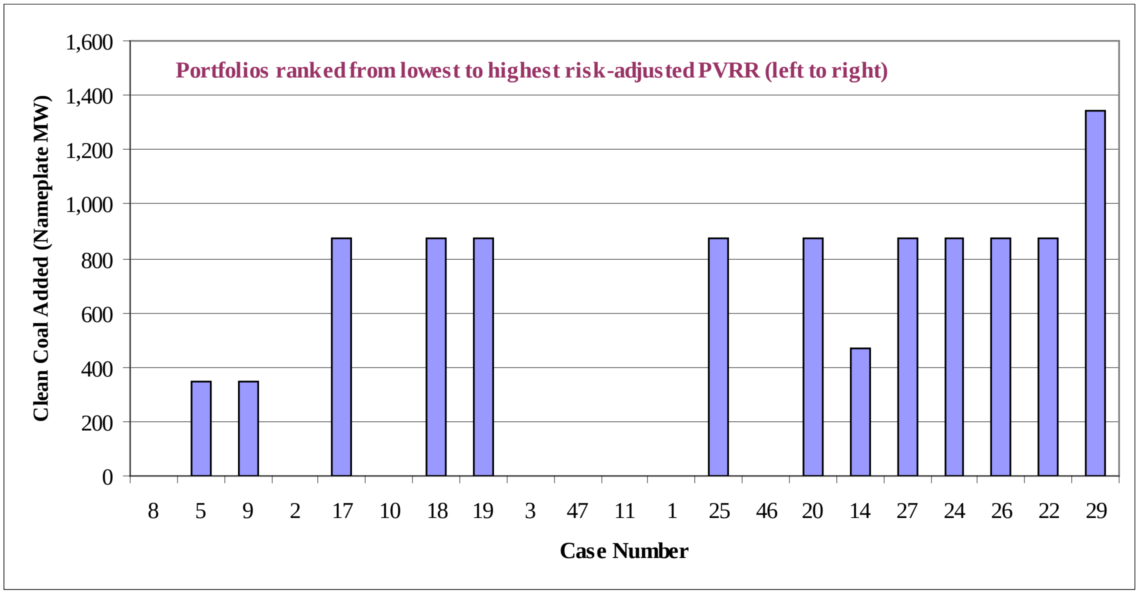
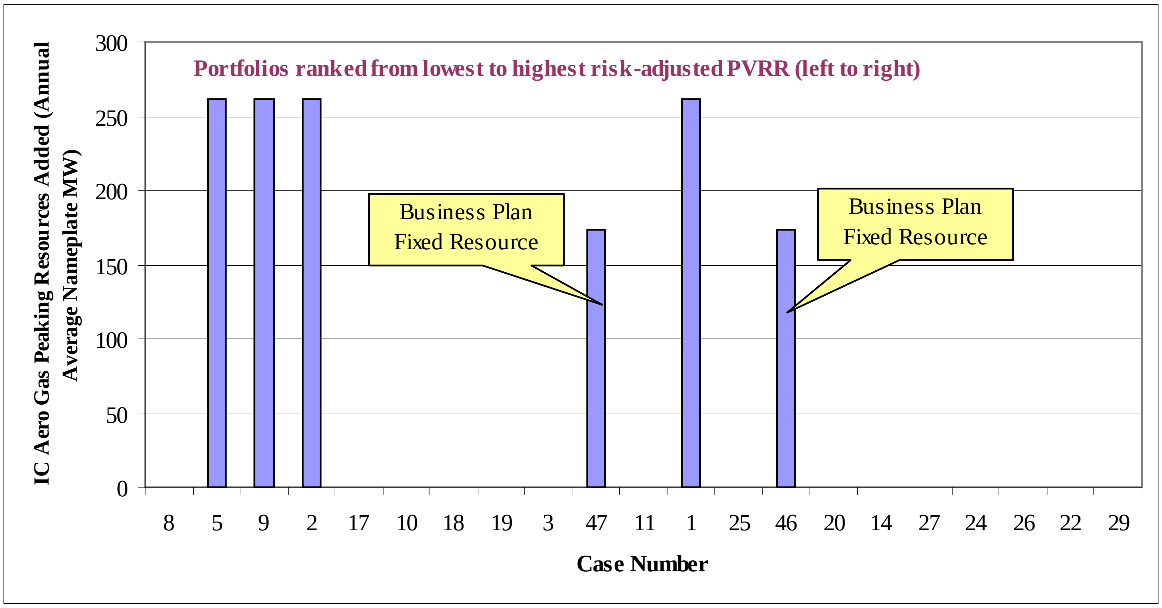


Figure 8.7 – IC Aeroderivative SCCT Capacity for Portfolios Ranked by Risk-adjusted PVRR



Customer Rate Impact

The portfolio customer rate impacts for each CO_2 tax simulation, and averaged across the simulations, are reported in Table 8.10. This measure is given a 20 percent weight for determining the overall portfolio preference scores.

With no CO_2 tax, the portfolios for cases 1 and 2 perform the best due to the lack of wind investment. Case 1, which has the lowest rate impact, has no wind additions other than the firm planned resources in 2009 and 2010. Case 2, which ranked second, has only 338 MW of wind added by 2018, but includes a 600 MW super-critical coal plant in 2018. Under the $45 CO_2 tax, the top performers are the portfolios for cases 9 and 5. Case 9 has slightly more wind resources than case 5 (by 230 MW) and less front office transactions. Under the $100 CO_2 tax, the top performers are cases 20 and 17. Case 20 relies on a nuclear plant in 2025 and more wind than for case 17.

When averaging the results across the CO_2 tax levels, cases 9 and 5 fare the best; they rank first and second, respectively.

Table 8.10 – Customer Rate Impacts by Portfolio

Case	CO_2 Tax Level (2009$)			Average	Rank
	$0/ton	$45/ton	$100/ton		
1	2.82	6.28	10.16	6.42	8
2	2.89	6.31	10.06	6.42	7
3	3.49	6.58	9.74	6.61	14
5	2.95	6.11	9.54	6.20	2
8	3.08	6.19	9.48	6.25	5
9	2.93	6.09	9.52	6.18	1
10	3.24	6.31	9.64	6.40	6
11	3.34	6.22	9.11	6.22	3
14	4.09	6.97	9.80	6.95	16
17	3.48	6.22	9.03	6.24	4
18	3.61	6.41	9.33	6.45	9
19	3.66	6.43	9.28	6.46	10
20	4.24	6.62	8.92	6.59	13
22	4.78	7.30	9.70	7.26	18
24	5.22	7.51	9.70	7.48	20
25	3.95	6.57	9.20	6.58	12
26	5.09	7.41	9.66	7.39	19
27	4.99	7.19	9.27	7.15	17
29	5.71	7.96	10.07	7.91	21
46	3.16	6.55	10.22	6.64	15
47	2.99	6.39	10.09	6.49	11

Cost Exposure under Alternative Carbon Dioxide Tax Levels

As discussed in Chapter 7, cost exposure is the difference between a portfolio's risk-adjusted PVRR and the risk-adjusted PVRR of the best-performing portfolio for a given CO_2 tax level. Portfolio performance under this measure is gauged by the size of the worst loss that could be realized under the three CO_2 tax levels if the chosen portfolio turns out to not be the optimal one based on risk-adjusted PVRR. This measure was assigned a 15 percent weight for determining the overall portfolio preference scores.

Table 8.11 presents the cost exposure results for the CO_2 tax simulations, with no probability weights applied. As indicated in the table, the potential cost exposure is large for portfolios built in response to an extreme CO_2 tax value, and where the realized CO_2 tax turns out to be at the other extreme. The cost exposures range from $30 million for case 17 under a realized $100/ton tax, to $11 billion for case 29 given no CO_2 tax. (Note that portfolios with no cost exposure value reported have the lowest cost at that CO_2 tax level.)

To be consistent with the probability-weighted approach used to rank portfolio performance, the maximum loss values are probability-weighted as well.

Table 8.11 – Portfolio Cost Exposures for Carbon Dioxide Tax Outcomes

Case	CO2 Tax Level, Million Dollars (2009$)				Rank
	$0/ton	$45/ton	$100/ton	Maximum Loss	
1	486	956	5,546	5,546	13
2	-	354	4,042	4,042	10
3	3,104	1,417	1,408	3,104	5
5	859	132	2,610	2,610	3
8	1,436	-	1,084	1,436	1
9	983	249	2,717	2,717	4
10	2,170	678	2,040	2,170	2
11	3,965	1,718	1,102	3,965	8
14	5,916	3,202	1,502	5,916	15
17	3,667	883	30	3,667	7
18	3,503	955	533	3,503	6
19	4,026	1,290	566	4,026	9
20	6,808	2,819	122	6,808	16
22	8,093	4,304	1,342	8,093	17
24	8,786	4,225	543	8,786	20
25	5,601	2,055	-	5,601	14
26	8,480	4,152	984	8,480	18
27	8,745	4,200	543	8,745	19
29	11,090	6,433	2,588	11,090	21
46	1,749	1,835	5,137	5,137	12
47	727	885	4,341	4,341	11

Portfolio Capital Costs

Figures 8.8 and 8.9 show the capital costs for each portfolio, expressed on a net present value basis for costs accrued for 2009-2018 and 2009-2028, respectively. (The 2009-2018 capital cost measure was assigned a five percent weight for determining the portfolio preference scores.)

The portfolios with the lowest capital costs are for cases 1, 2, and 5. Case 1, with a capital cost of $0.5 billion, relies more heavily on market purchases, distributed generation, and Class 1 DSM than the other low capital cost portfolios, and reflects no incremental wind investment past 2010.

In contrast, the high-cost portfolios—such as cases 29, 22, 27, and 24—reflect large investments in wind, clean coal, and nuclear plants to mitigate the CO_2 tax liabilities.

Figure 8.8 – Portfolio Capital Costs, 2009-2018

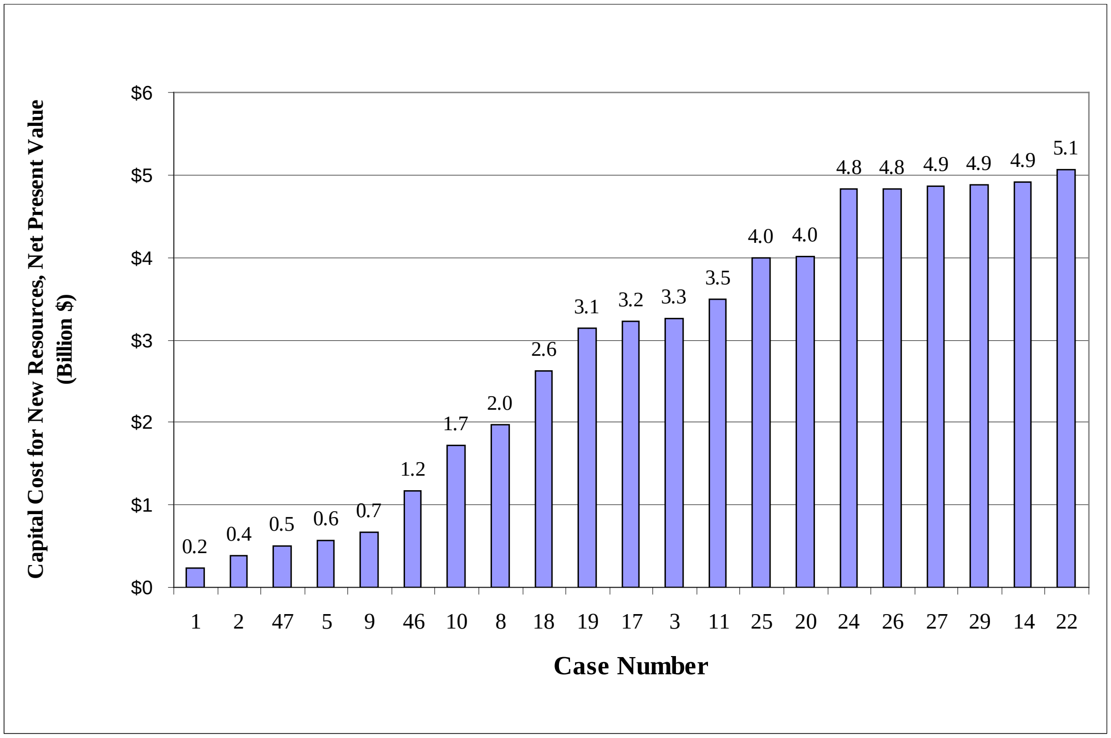
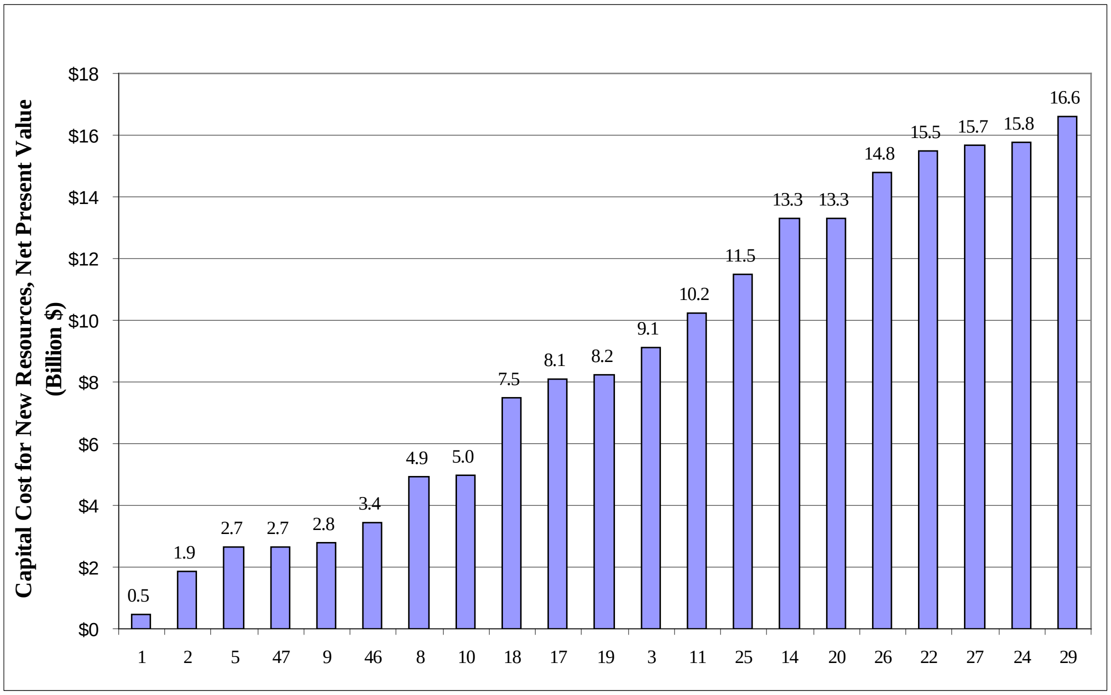
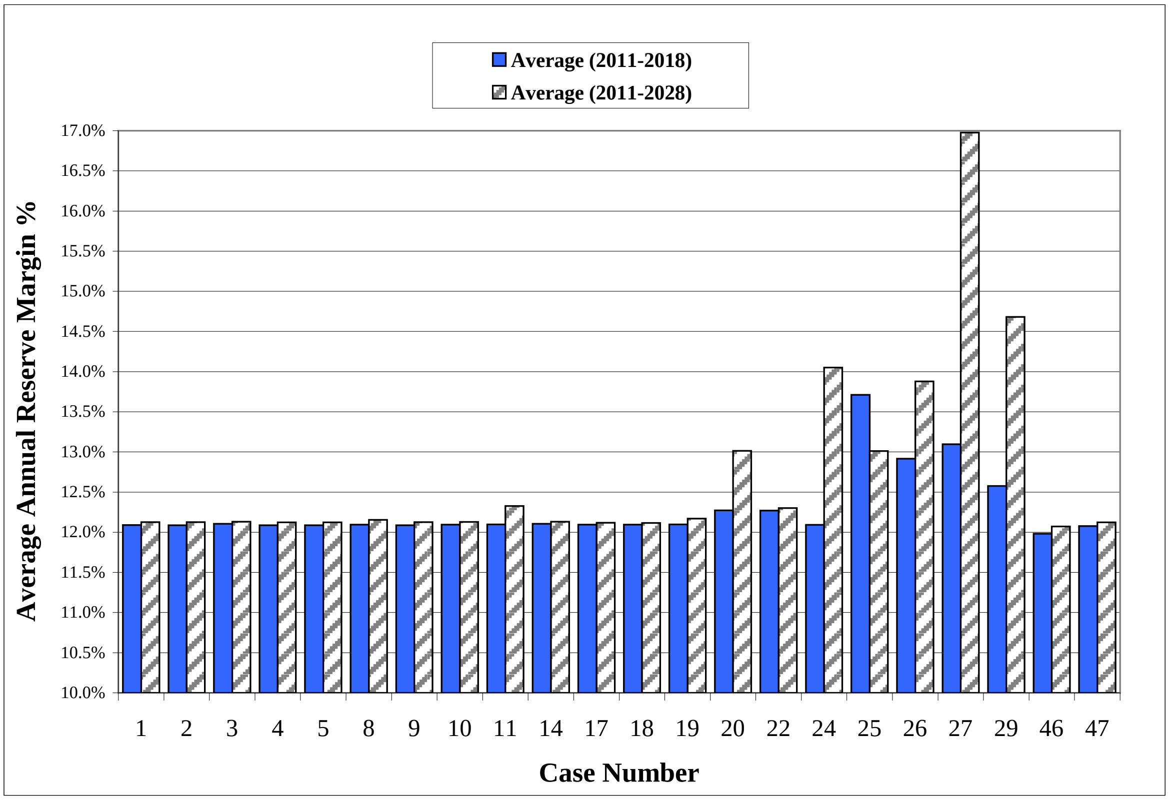


Figure 8.9 – Portfolio Capital Costs, 2009-2028



The impact of such investments on capacity planning reserve margins, particularly in the out years, is indicated in Figure 8.10. This figure shows average annual reserve margins for 2011 to 2018 (reflecting the start of the system capacity short position) as well as for 2011 to 2028. The association between extensive clean generation investment and excess planning reserve margins is clearly seen with margins far exceeding the 12 percent requirement reflected in the model.[48]

Figure 8.10 – Average Annual Planning Reserve Margins



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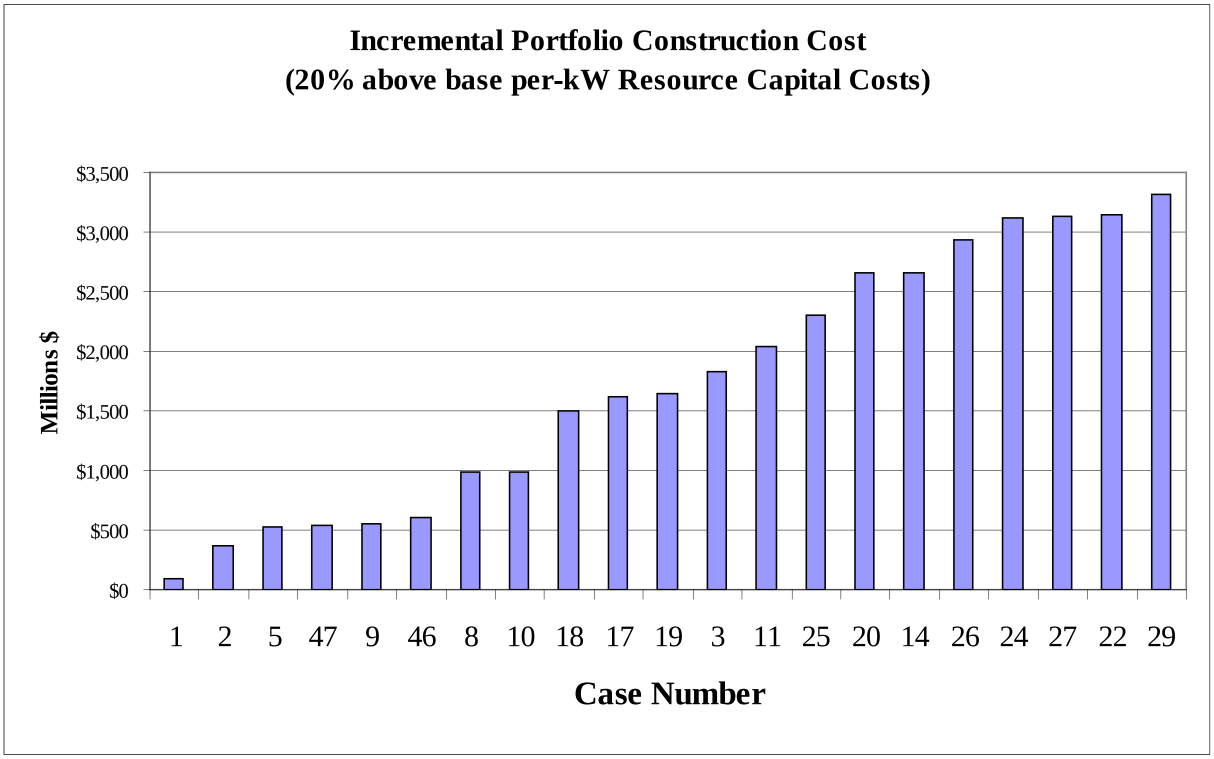
[48] The 2011-2028 average annual planning reserve margins for case 11, which was based on a $45/ton CO_2 tax, is higher than for the other core cases with this tax level. Unlike the other $45 tax cases, case 11 was modeled with high gas prices. This case experienced greater west-east transfers than the other cases for 2026-2028, supported by a relatively larger amount of growth resources and front office transactions on the west side.

Figure 8.11 shows the impact on portfolio capital costs given a 20 percent increase in the per-kilowatt capital cost for all resources.

Figure 8.11 – Incremental Portfolio Capital Costs (20% increase from Base per-kW values)



Upper-tail Mean PVRR

Table 8.12 reports the upper-tail mean PVRR results for the individual CO_2 tax simulations and the average.

Cases 22 and 14 perform the best. Case 22 includes both pulverized coal and nuclear plants in response to a $70/ton CO_2 tax and high gas/electricity prices. Case 14 also includes pulverized coal as well as an IGCC plant in 2025. Both portfolios feature heavy reliance on wind resources (7,200 MW for case 22 and 6,300 MW for case 14), and consequently rely on less front office transactions and gas plant dispatch.

Table 8.12 – Upper-tail Mean PVRR by Portfolio

	CO2 Tax Level, Million Dollars (2009$)				
Case	**$0/ton**	**$45/ton**	**$100/ton**	**Average**	**Rank**
1	57,487	80,005	114,973	84,155	21
2	51,169	73,646	107,193	77,336	16
3	44,084	65,519	94,991	68,198	5

	CO2 Tax Level, Million Dollars (2009$)				
Case	**$0/ton**	**$45/ton**	**$100/ton**	**Average**	**Rank**
5	53,047	74,487	106,969	78,168	19
8	49,843	70,581	101,048	73,824	14
9	53,347	74,736	107,163	78,415	20
10	52,335	72,023	102,956	75,771	15
11	44,638	65,642	94,453	68,244	6
14	44,778	65,453	93,021	67,751	2
17	49,328	68,766	96,941	71,678	11
18	50,209	69,834	98,591	72,878	13
19	50,320	69,705	98,022	72,682	12
20	46,767	66,084	92,486	68,446	7
22	45,569	65,404	91,170	67,381	1
24	46,980	65,939	91,142	68,020	4
25	48,112	66,967	94,182	69,754	10
26	47,587	66,665	92,520	68,924	8
27	46,732	65,701	90,907	67,780	3
29	48,734	67,670	92,365	69,590	9
46	52,224	74,442	107,516	78,061	18
47	51,559	73,905	107,252	77,572	17

The following charts present the megawatt capacities for the portfolios ranked by upper-tail mean PVRR, focusing on the resource types most consequential for determining upper-tail cost risk. Figures 8.12 and 8.13 show the portfolio wind and energy efficiency capacities, indicating that upper-tail cost risk is inversely proportional to the amount of these resources added. Figures 8.14 and 8.15 show the front office transactions (on an average annual basis) and peaking gas capacities, respectively. Portfolios with more of these resource types tend to exhibit higher upper-tail cost risk.

Figure 8.12 – Wind Capacity for Portfolios Ranked by Upper-tail Mean PVRR

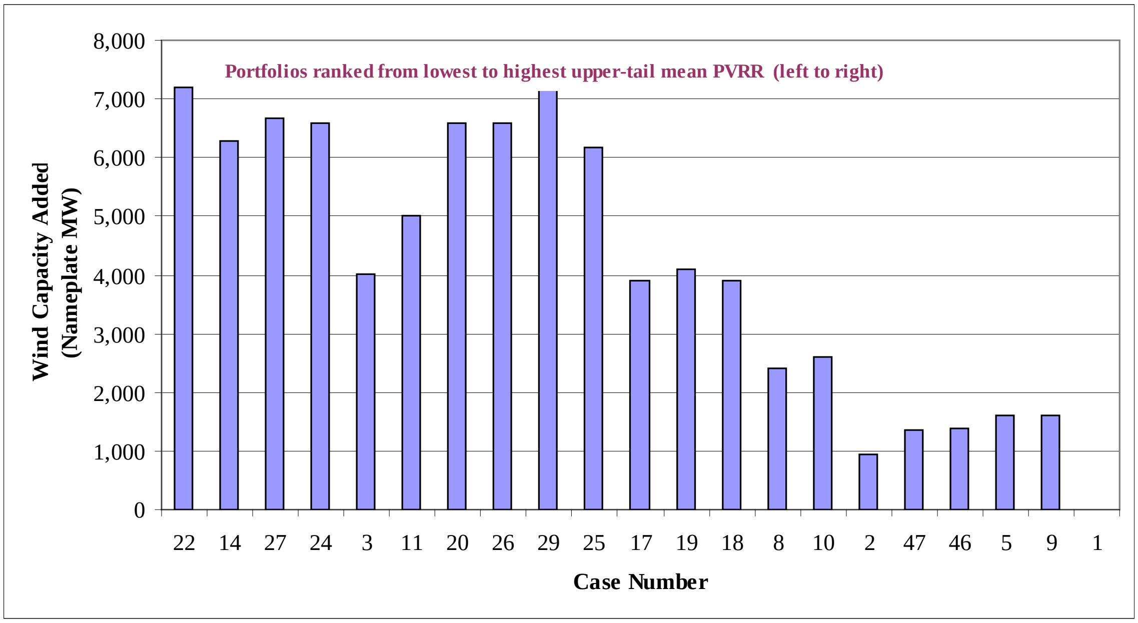


Figure 8.13 – Energy Efficiency Capacity for Portfolios Ranked by Upper-tail Mean PVRR

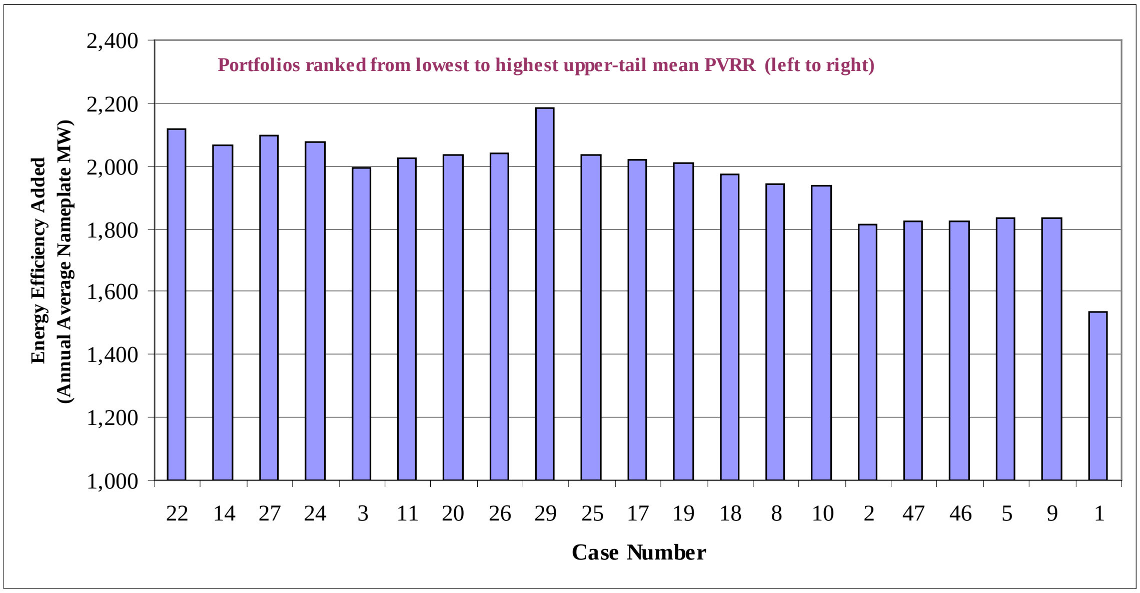


Figure 8.14 – Front Office Transaction Capacity for Portfolios Ranked by Upper-tail Mean PVRR

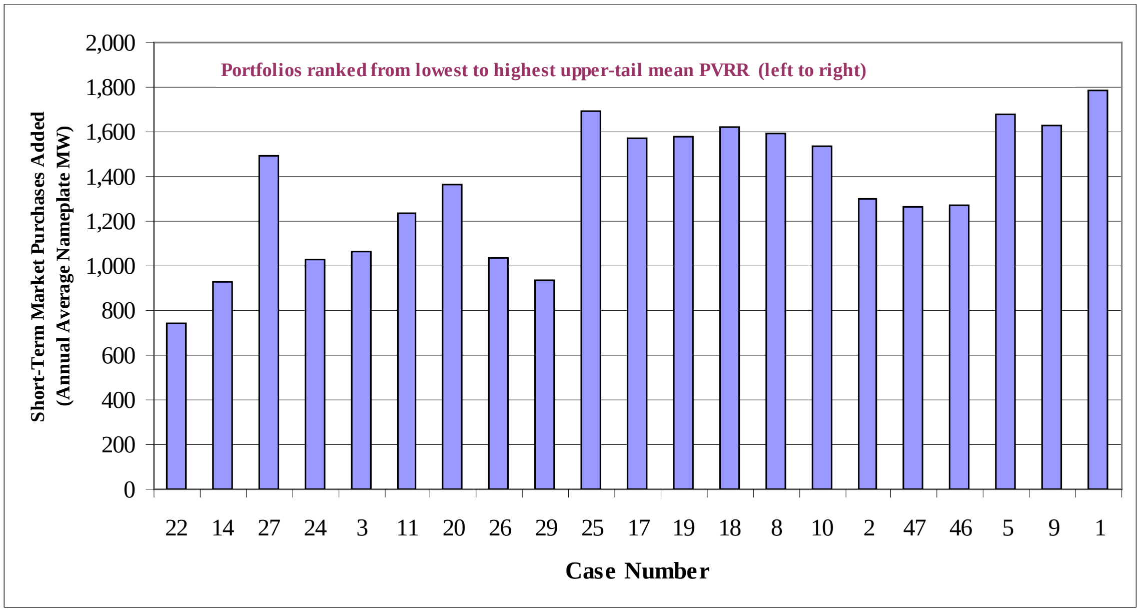
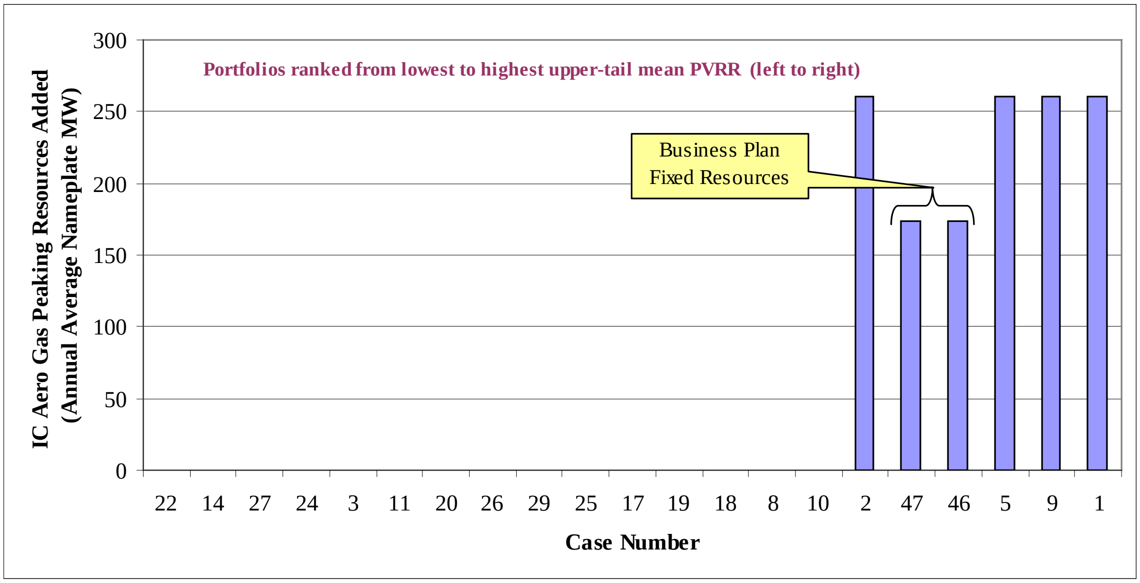


Figure 8.15 – Intercooled Aeroderivative SCCT Capacity for Portfolios Ranked by Upper-tail Mean PVRR



Mean/Upper-Tail Cost Scatter Plots

Figures 8.16 through 8.18 are scatter plots of portfolio cost (mean PVRR) versus high-end cost risk as represented by the upper-tail mean PVRR. These scatter plots show the trade-off between cost and risk at the different CO_2 tax levels.

Across the CO_2 tax levels, there are no portfolios that dominate all others for both mean PVRR and upper-tail mean PVRR. For the $0/ton tax, the case 2 and 3 portfolios dominate all others for mean PVRR and upper-tail mean PVRR, respectively. For the $45/ton tax, the dominant (or nearly dominant) portfolios are represented by cases 8 and 5 for mean PVRR, and cases 22, 14, and 3 for the upper-tail mean. For the $100/ton tax, the dominating portfolios include cases 17 and 25 for mean PVRR, and 27, 22, and 24 for upper-tail mean PVRR.

Figure 8.19 is the scatter plot for the cost and risk measures expressed as averages across the CO_2 tax simulations. Cases 8 and 5 dominate on mean PVRR, while cases 22, 27, and 14 dominate on upper-tail mean PVRR.

Figure 8.16 – Stochastic Cost versus Upper-tail Risk, $0 CO_2 Tax

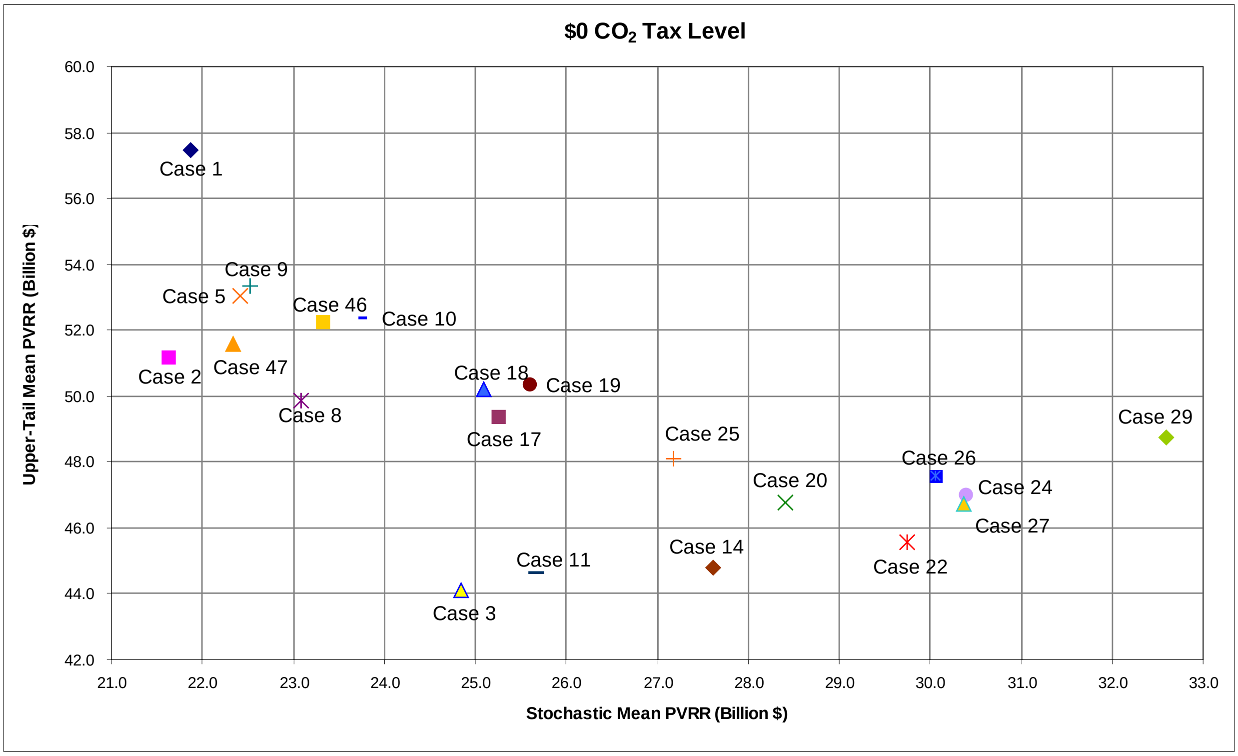


Figure 8.17 – Stochastic Cost versus Upper-tail Risk, $45 CO_2 Tax

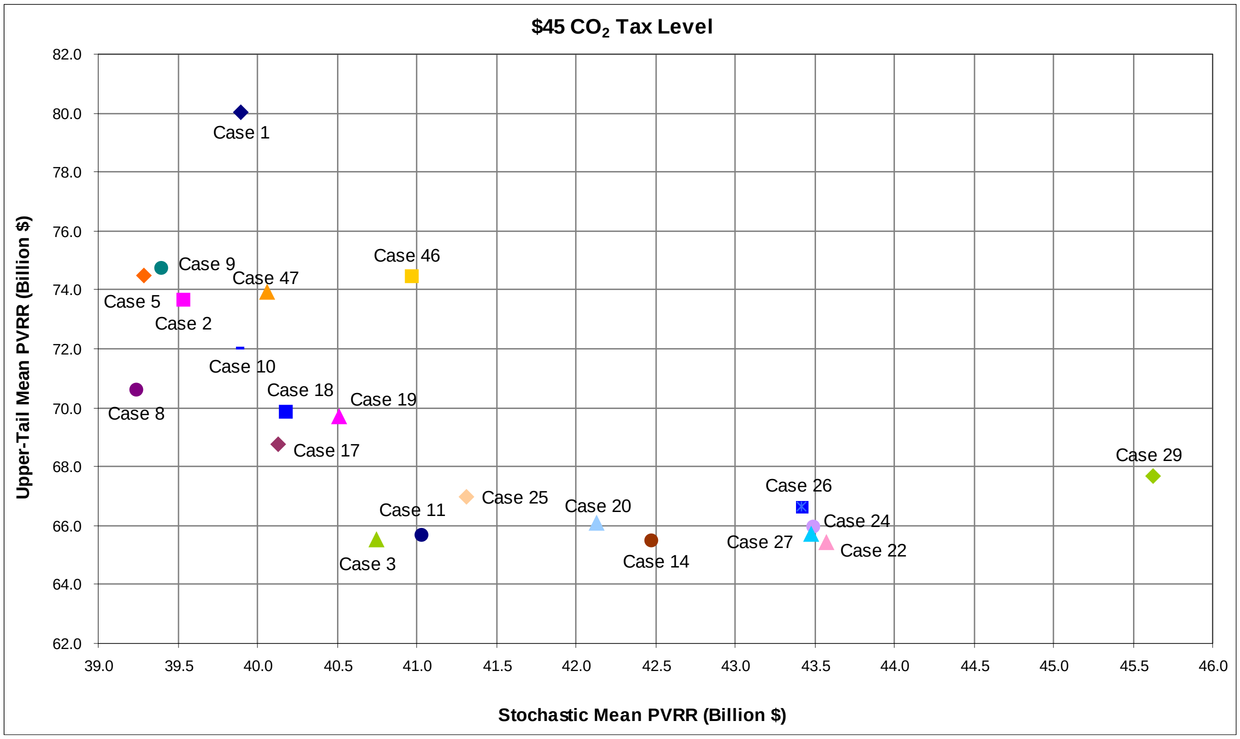


Figure 8.18 – Stochastic Cost versus Upper-tail Risk, $100 CO_2 Tax

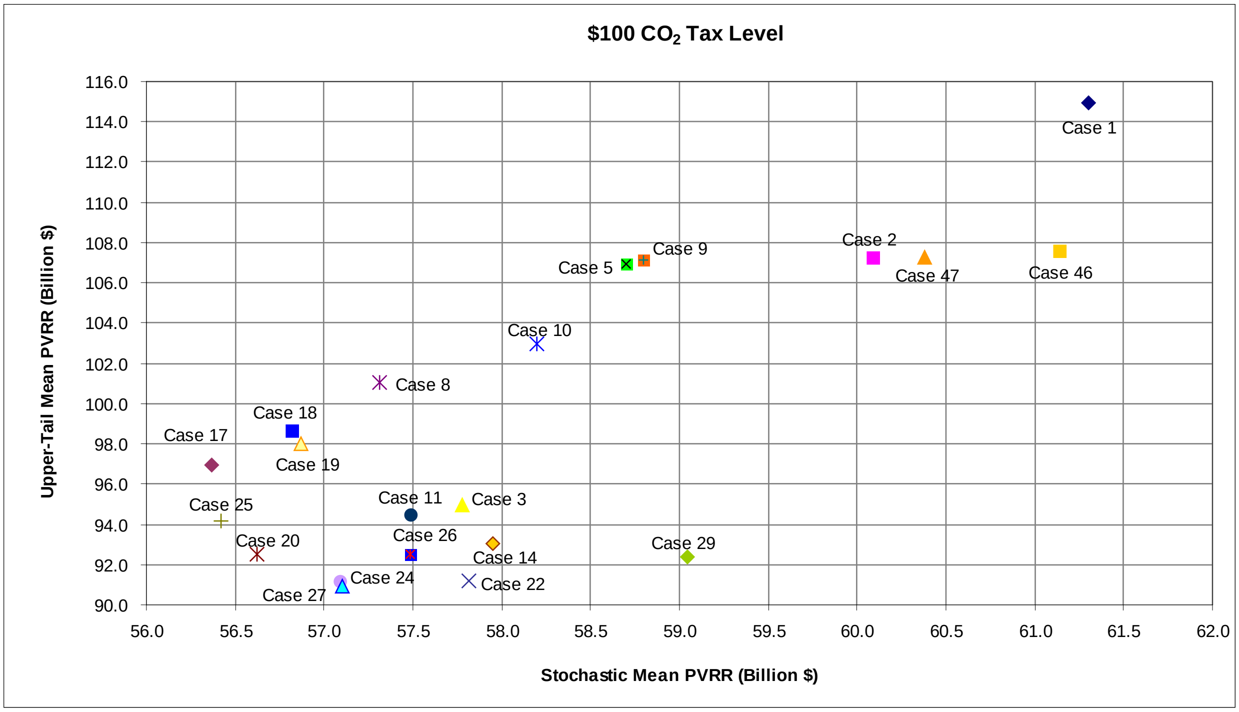
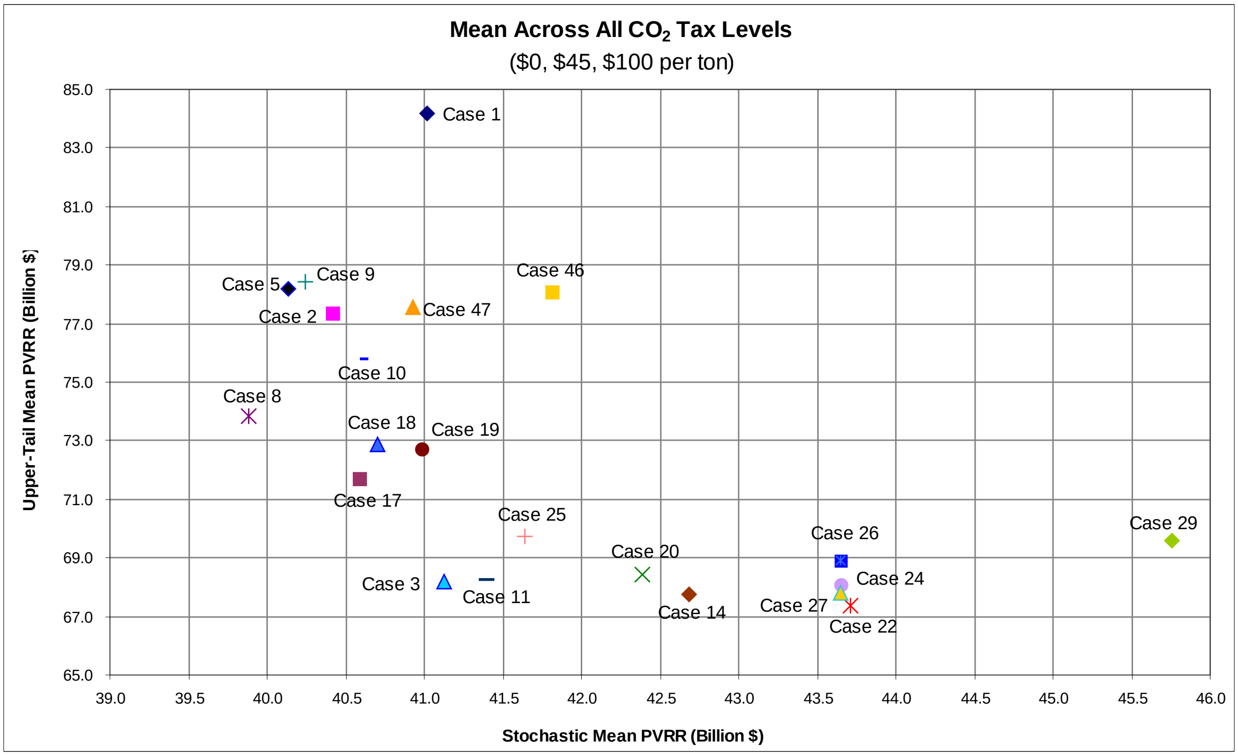


Figure 8.19 – Stochastic Cost versus Upper-tail Risk, Average for CO_2 Tax Levels



Fifth and Ninety-Fifth Percentile PVRR

Table 8.13 reports the 5th and 95th percentile PVRR results for each of the CO_2 tax simulations. Straight averages across the simulations are also shown. The 95th percentile PVRRs are incorporated into the risk-adjusted PVRR results shown above.

Table 8.13 – 5th and 95th Percentile PVRR by Portfolio

	CO2 Tax Level, Million Dollars (2009$)						Average 5th Percentile	Average 95th Percentile
	$0/ton		$45/ton		$100/ton			
Case	5th Percentile	95th Percentile	5th Percentile	95th Percentile	5th Percentile	95th Percentile		
1	12,783	42,378	25,788	64,012	37,447	95,821	25,339	67,404
2	13,242	37,288	26,367	58,989	38,006	89,768	25,872	62,015
3	16,195	35,313	28,995	56,205	39,187	83,429	28,126	58,316
5	13,824	38,965	26,143	59,619	36,667	89,078	25,544	62,554
8	15,227	37,008	25,594	57,877	36,925	86,354	25,916	60,413
9	13,845	39,135	26,254	59,775	36,833	89,222	25,644	62,711
10	15,530	39,069	26,786	58,877	37,377	87,726	26,564	61,890
11	16,042	36,143	29,664	56,410	38,989	83,010	28,232	58,521
14	18,323	36,047	31,913	57,172	39,748	81,853	29,995	58,357
17	17,939	38,113	27,689	57,738	37,331	84,101	27,653	59,984
18	17,497	38,334	27,366	58,161	37,552	85,095	27,472	60,530
19	18,038	38,656	27,945	58,283	37,923	84,818	27,968	60,586
20	19,002	38,039	31,958	56,595	38,589	80,918	29,849	58,518
22	20,516	36,950	32,172	57,320	39,783	81,455	30,823	58,575

Case	CO2 Tax Level, Million Dollars (2009$)						Average 5th Percentile	Average 95th Percentile
	$0/ton		$45/ton		$100/ton			
	5th Percentile	95th Percentile	5th Percentile	95th Percentile	5th Percentile	95th Percentile		
24	21,323	37,971	33,686	57,338	39,783	79,882	31,597	58,397
25	18,385	38,596	29,912	57,527	38,267	82,511	28,855	59,545
26	21,408	38,599	33,688	57,464	40,050	80,862	31,715	58,975
27	21,363	37,689	33,220	57,212	40,064	79,636	31,549	58,179
29	23,269	39,889	34,029	58,893	42,020	81,822	33,106	60,201
46	15,085	38,385	27,953	59,954	39,326	90,703	27,455	63,014
47	14,048	37,753	26,881	59,283	38,290	90,150	26,406	62,395

Production Cost Standard Deviation

The standard deviation of stochastic production costs for each portfolio and the average is shown in table 8.14. (Probability-weighted average values based on alternative expected value CO_2 tax levels are reported in Table 8.27.) This risk measure was assigned a five percent weight for determination of the portfolio preference scores.

As expected, portfolios that rely on coal, wind, and nuclear resources exhibit the lowest levels of production cost variability.

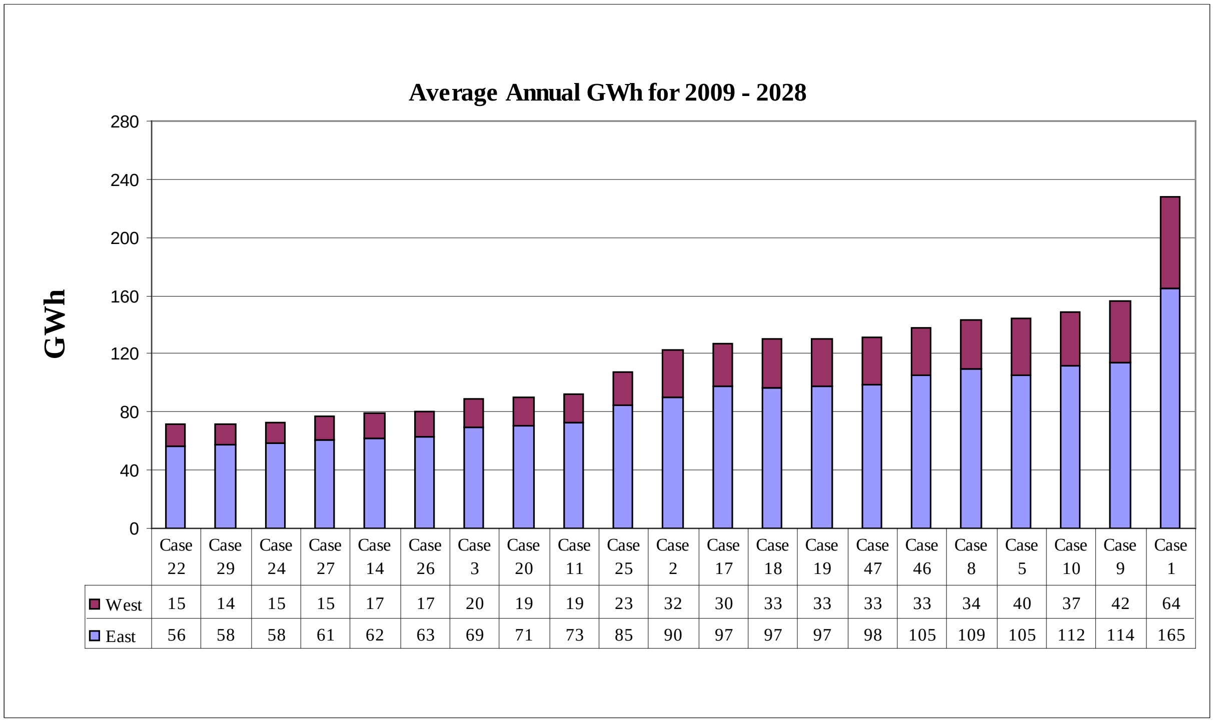
Table 8.14 – Production Cost Standard Deviation

Case	CO2 Tax Level, Million Dollars (2009$)				Rank
	$0/ton	$45/ton	$100/ton	Average	
1	10,486	12,939	18,966	14,130	21
2	8,795	11,312	17,234	12,447	18
3	6,484	8,845	14,129	9,819	9
5	9,067	11,549	17,422	12,679	19
8	8,083	10,534	16,156	11,591	14
9	9,104	11,565	17,412	12,694	20
10	8,552	10,733	16,424	11,903	15
11	6,499	8,778	13,958	9,745	8
14	6,106	8,256	13,205	9,189	6
17	7,438	9,799	15,133	10,790	11
18	7,655	10,033	15,439	11,042	13
19	7,566	9,906	15,238	10,904	12
20	6,336	8,460	13,255	9,350	7
22	5,860	7,854	12,459	8,724	2
24	5,904	7,955	12,530	8,796	4
25	6,808	9,041	14,090	9,980	10
26	6,094	8,201	12,880	9,058	5
27	5,893	7,909	12,434	8,745	3
29	5,920	7,844	12,242	8,669	1
46	8,628	11,142	17,029	12,266	16
47	8,708	11,251	17,188	12,382	17

Energy Not Served (ENS)

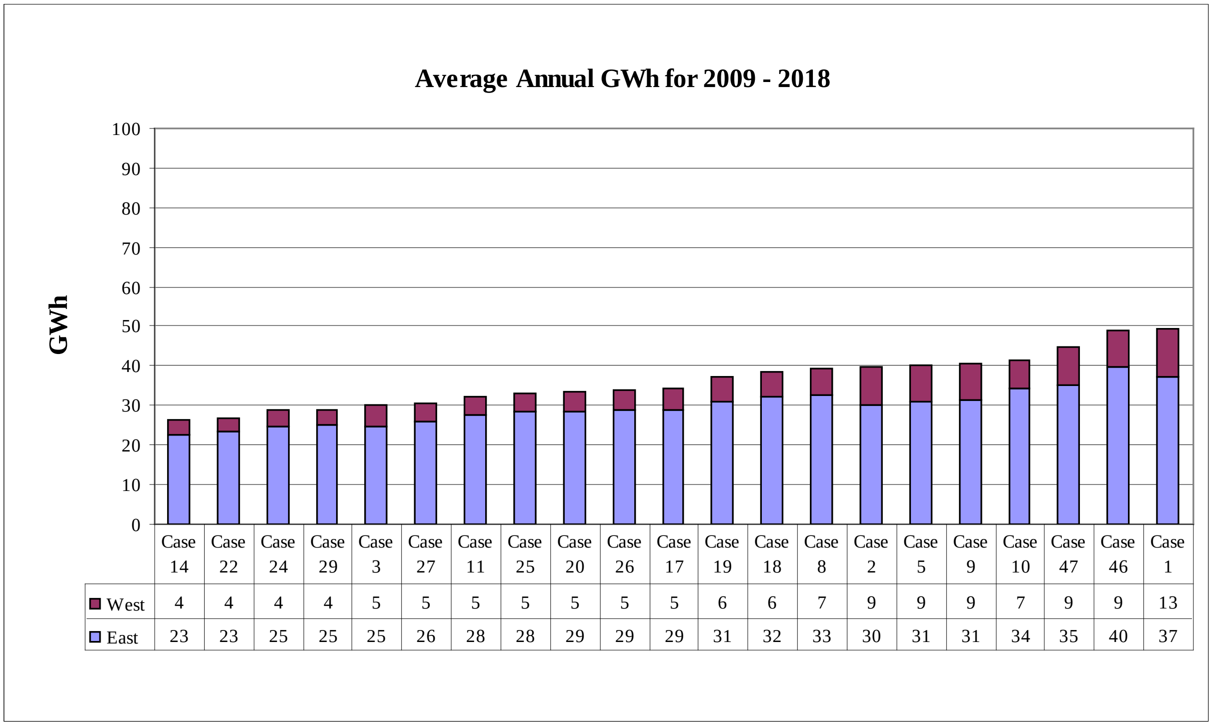
Figures 8.20 and 8.21 below show, respectively, the average annual amount of Energy Not Served (ENS) for the periods 2009-2028 and 2009-2018. Figure 8.22 shows the upper-tail mean ENS by portfolio. As explained in Chapter 7, these are measures of high-end supply reliability risk. Portfolios with low ENS include coal and nuclear, as well as relatively large quantities of wind. Portfolios with relatively high amounts of ENS rely to a greater degree on front office transactions, and in the out-years, growth resources.

Figure 8.20 – Average Annual Energy Not Served, 2009-2028 ($45 CO_2 Tax)



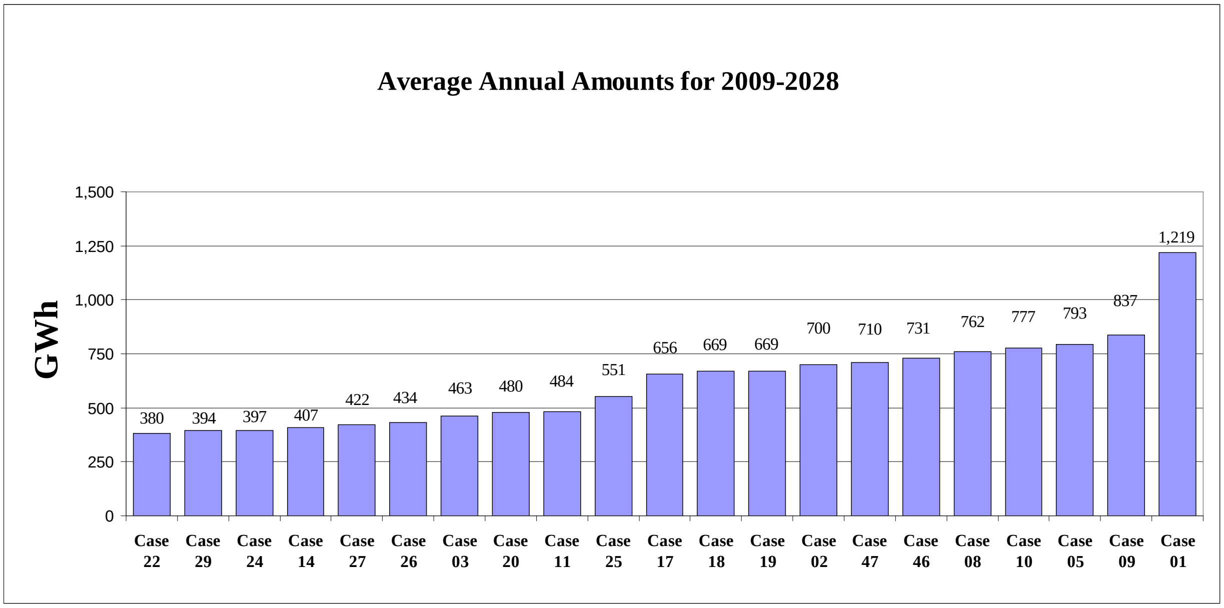
	Case 22	Case 29	Case 24	Case 27	Case 14	Case 26	Case 3	Case 20	Case 11	Case 25	Case 2	Case 17	Case 18	Case 19	Case 47	Case 46	Case 8	Case 5	Case 10	Case 9	Case 1
■ West	15	14	15	15	17	17	20	19	19	23	32	30	33	33	33	33	34	40	37	42	64
□ East	56	58	58	61	62	63	69	71	73	85	90	97	97	97	98	105	109	105	112	114	165

Figure 8.21 – Average Annual Energy Not Served, 2009-2018 ($45 CO_2 Tax)



	Case 14	Case 22	Case 24	Case 29	Case 3	Case 27	Case 11	Case 25	Case 20	Case 26	Case 17	Case 19	Case 18	Case 8	Case 2	Case 5	Case 9	Case 10	Case 47	Case 46	Case 1
■ West	4	4	4	4	5	5	5	5	5	5	5	6	6	7	9	9	9	7	9	9	13
□ East	23	23	25	25	25	26	28	28	29	29	29	31	32	33	30	31	31	34	35	40	37

Figure 8.22 – Upper-tail Energy Not Served, $45 CO_2 Tax



Loss of Load Probability

As discussed in Chapter 7, Loss of Load Probability (LOLP) is represented by the probability of an occurrence of Energy Not Served. Table 8.15 displays the average LOLP for each of the candidate portfolios during the summer peak at various ENS event thresholds, modeled using the \$45 CO_2 tax assumption. The first block of data is the average LOLP for the first ten years of the study period. The second block of data shows the same information calculated for the entire 20 years. The LOLP values in the second block are significantly higher than the first because the variability of the random draws for the stochastic variable draws increases over time, causing greater extremes in the out-years of the study period.

Table 8.16 displays the year-by-year results for the threshold value of 25,000 MWh. For each year, the LOLP value represents the proportion of the 100 simulation iterations where the July ENS was greater than 25,000 MWh. This is the equivalent of 2,500 megawatts for 10 hours. The annual average LOLPs from Table 8.16 constitute one of the supply reliability risk measures used for overall portfolio preference scoring, and is given a five percent weight for this purpose.

Table 8.15 – Average Loss of Load Probability by Event Size During Summer Peak

Average for operating years 2009 through 2018										
Event Size (MWh)	**Case Number**									
	1	**2**	**3**	**5**	**8**	**9**	**10**	**11**	**14**	**17**
> 0	40%	39%	38%	39%	42%	39%	42%	39%	36%	41%
> 1,000	32%	32%	30%	32%	35%	31%	34%	33%	29%	34%
> 10,000	19%	18%	16%	18%	20%	18%	20%	18%	15%	18%
> 25,000	13%	11%	10%	12%	13%	12%	13%	11%	9%	12%
> 50,000	8%	7%	6%	7%	8%	7%	8%	7%	6%	7%
> 100,000	5%	4%	4%	5%	5%	5%	5%	4%	3%	4%
> 500,000	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2009 through 2028										
Event Size (MWh)	**Case Number**									
	1	**2**	**3**	**5**	**8**	**9**	**10**	**11**	**14**	**17**
> 0	42%	39%	42%	39%	45%	41%	45%	43%	41%	44%
> 1,000	37%	33%	35%	34%	38%	35%	38%	36%	34%	37%
> 10,000	26%	21%	23%	22%	25%	23%	27%	24%	22%	25%
> 25,000	21%	16%	16%	17%	19%	18%	20%	16%	15%	19%
> 50,000	16%	12%	12%	13%	14%	14%	15%	12%	11%	14%
> 100,000	12%	9%	8%	10%	10%	11%	11%	8%	7%	10%
> 500,000	4%	3%	2%	3%	3%	3%	3%	2%	2%	3%
> 1,000,000	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Average for operating years 2009 through 2018											
Event Size (MWh)	**Case Number**										
	18	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
> 0	42%	41%	39%	37%	37%	40%	40%	37%	37%	44%	42%
> 1,000	34%	34%	33%	30%	30%	33%	33%	30%	30%	37%	35%
> 10,000	20%	19%	18%	16%	16%	18%	18%	16%	16%	23%	21%
> 25,000	13%	12%	11%	10%	10%	11%	11%	10%	10%	14%	13%
> 50,000	8%	8%	7%	6%	6%	7%	7%	7%	6%	9%	8%
> 100,000	4%	4%	4%	3%	3%	4%	4%	3%	3%	6%	5%
> 500,000	1%	1%	1%	0%	1%	0%	1%	0%	0%	1%	1%

Average for operating years 2009 through 2018											
Event Size (MWh)	**Case Number**										
	18	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2009 through 2028											
Event Size (MWh)	**Case Number**										
	18	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
> 0	45%	45%	43%	42%	42%	43%	43%	42%	42%	47%	45%
> 1,000	38%	38%	37%	35%	35%	37%	37%	35%	35%	41%	38%
> 10,000	26%	26%	24%	22%	22%	24%	24%	23%	23%	27%	26%
> 25,000	19%	19%	17%	15%	15%	18%	17%	16%	16%	20%	19%
> 50,000	14%	14%	12%	11%	11%	13%	12%	11%	11%	14%	14%
> 100,000	10%	10%	8%	7%	7%	9%	8%	7%	7%	11%	10%
> 500,000	3%	3%	2%	2%	1%	3%	2%	2%	2%	3%	3%
> 1,000,000	1%	1%	1%	0%	0%	1%	0%	0%	0%	1%	1%

Table 8.16 – Year-by-Year Loss of Load Probability

Probability of ENS Event > 25,000 MWh in July

	Case Number									
Year	**1**	**2**	**3**	**5**	**8**	**9**	**10**	**11**	**14**	**17**
2009	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
2010	14%	12%	10%	12%	12%	12%	12%	11%	9%	11%
2011	9%	9%	8%	9%	9%	9%	9%	9%	8%	9%
2012	7%	7%	5%	7%	7%	7%	7%	7%	5%	7%
2013	17%	14%	10%	14%	12%	17%	16%	13%	10%	12%
2014	18%	17%	8%	17%	17%	19%	17%	10%	8%	16%
2015	17%	15%	10%	15%	15%	15%	15%	10%	10%	10%
2016	11%	11%	13%	11%	15%	11%	15%	13%	11%	13%
2017	8%	6%	12%	6%	14%	6%	14%	11%	11%	14%
2018	23%	19%	19%	20%	23%	20%	23%	19%	17%	21%
2019	21%	12%	16%	15%	18%	15%	18%	15%	15%	17%
2020	22%	15%	19%	19%	23%	19%	23%	19%	19%	22%
2021	24%	17%	22%	19%	20%	21%	24%	22%	22%	23%
2022	26%	12%	15%	17%	16%	17%	22%	16%	15%	21%
2023	30%	25%	25%	25%	30%	28%	30%	25%	24%	30%
2024	30%	23%	21%	22%	23%	25%	27%	23%	21%	24%
2025	39%	27%	27%	36%	39%	36%	35%	30%	27%	36%
2026	30%	25%	25%	27%	29%	26%	29%	26%	25%	29%
2027	26%	21%	22%	25%	27%	25%	27%	23%	22%	23%
2028	35%	25%	25%	26%	29%	29%	31%	20%	23%	28%

	Case Number										
Year	**18**	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
2009	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
2010	12%	12%	11%	9%	9%	11%	11%	11%	10%	12%	12%
2011	9%	9%	9%	8%	8%	9%	9%	8%	8%	9%	9%
2012	7%	7%	7%	5%	5%	7%	7%	5%	5%	7%	7%
2013	17%	14%	12%	10%	10%	13%	13%	10%	10%	12%	12%

	Case Number										
Year	**18**	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
2014	18%	18%	13%	8%	8%	13%	13%	10%	9%	17%	17%
2015	15%	10%	10%	10%	10%	10%	10%	10%	10%	15%	15%
2016	13%	13%	13%	13%	13%	13%	13%	13%	13%	16%	15%
2017	14%	14%	13%	11%	11%	12%	13%	12%	12%	21%	14%
2018	21%	21%	21%	17%	20%	20%	21%	21%	19%	26%	23%
2019	17%	17%	16%	15%	15%	15%	16%	16%	15%	21%	18%
2020	22%	22%	21%	19%	21%	21%	21%	21%	21%	24%	23%
2021	23%	23%	23%	22%	23%	23%	23%	23%	23%	25%	23%
2022	20%	21%	17%	15%	16%	19%	17%	18%	17%	20%	18%
2023	30%	30%	28%	25%	25%	28%	29%	30%	27%	31%	29%
2024	25%	24%	24%	21%	21%	22%	22%	24%	21%	24%	24%
2025	36%	36%	29%	23%	24%	33%	24%	24%	23%	34%	33%
2026	29%	31%	27%	25%	24%	29%	24%	24%	24%	29%	28%
2027	23%	22%	21%	21%	20%	22%	20%	20%	20%	25%	24%
2028	29%	28%	23%	22%	22%	28%	22%	18%	20%	27%	26%

LOAD GROWTH IMPACT ON RESOURCE CHOICE

Table 8.17 reports selected stochastic cost and risk results for the cases developed with low and high load growth assumptions. Comparable medium load growth cases are included for reference purposes. The results are also grouped by gas price scenario to highlight the influence of gas and associated electricity prices on portfolio cost as load growth increases.

One observation gleaned from Table 8.17 is that the mix of resource added in response to higher load growth reduces high-end cost risk and Energy Not Served. The System Optimizer model tended to add wind and base-load resources (or CCCT capacity under low gas price scenarios), which reduced upper-tail costs. Much of the cost reduction is seen in the form of net revenue gains from spot market balancing transactions.

Table 8.17 – Stochastic Performance Results for Alternative Load Growth Scenario Cases

Case	Load Growth	Gas Price Scenario / FPC	Mean	5th Percentile	95th Percentile	Upper-Tail Mean	Production Cost Standard Deviation	Ave. Annual ENS (GWh/yr, 2009-2028)
$45/ton CO2 Tax								
4	Low	Low - June 2008	40,270	26,484	63,634	79,735	12,725	345.3
5	Med	Low - June 2008	39,289	26,143	59,619	74,487	9,067	144.6
6	High	Low - June 2008	39,635	27,311	58,044	71,364	10,639	37.7
7	Low	Medium - June 2008	39,877	26,747	59,769	74,618	11,395	255.1
8	Med	Medium - June 2008	39,244	25,594	57,877	70,581	10,534	143.4
12	High	Medium - June 2008	40,027	27,513	56,698	67,054	9,462	38.3
13	Low	High - June 2008	42,040	30,546	57,924	67,240	8,940	117.5
14	Med	High - June 2008	42,481	31,913	57,172	65,453	8,256	79.0

Case	Load Growth	Gas Price Scenario / FPC	Mean	5th Percentile	95th Percentile	Upper-Tail Mean	Production Cost Standard Deviation	Ave. Annual ENS (GWh/yr, 2009-2028)
15	High	High - June 2008	43,893	33,105	56,816	64,247	7,392	26.2
$70/ton CO2 Tax								
16	Low	Medium - June 2008	40,654	27,584	59,033	71,420	10,300	193.3
17	Med	Low - June 2008	42,481	27,689	57,738	68,766	7,438	127.1
21	Low	High - June 2008	43,038	32,516	58,082	67,686	8,677	107.6
22	Med	High - June 2008	43,576	32,172	57,320	65,404	7,854	71.3
$100/ton CO2 Tax								
23	Low	Medium - June 2008	43,624	33,987	57,827	66,798	8,177	88.6
24	Med	Medium - June 2008	43,496	33,686	57,338	65,939	7,955	72.7
28	Low	High - June 2008	43,602	32,764	58,070	67,305	8,376	94.0
29	Med	High - June 2008	45,626	34,029	58,893	67,670	7,844	72.1
33	High	High - June 2008	46,285	27,463	61,638	76,361	11,731	22.2

CAPACITY PLANNING RESERVE MARGIN

PacifiCorp compared stochastic cost and risk measures for portfolios built to meet 12 percent and 15 percent capacity planning reserve margins. This comparative analysis also examined the impact of the resource mix as the cost of CO_2 emission compliance increases, since resources added in response to high CO_2 costs, such as wind and energy efficiency programs, are not subject to fuel price volatility.[49] The relevant comparisons are cases 8 and 41 ($45 CO_2 tax), cases 17 and 42 ($70 CO_2 tax), and cases 24 and 43 ($100 CO_2 tax). Stochastic simulations were only conducted with the $45 CO_2 tax since ENS is not materially affected by differences in emission cost.

For the $45 CO_2 tax cases, increasing the planning reserve margin from 12 percent to 15 percent resulted in additional wind (135 MW) and east-side geothermal (35 MW) resources, as well as increased reliance on front office transactions on both the east and west sides, prior to 2016. The System Optimizer model added an IC aero SCCT in 2016 (261 MW) and subsequently cut back on additional wind resources and front office transactions. Table 8.18 shows the stochastic cost and risk results for the two case portfolios (cases 8 and 41), while Table 8.19 shows the detailed PVRR cost breakdown.

Building to the 15-percent PRM level increased costs and high-end cost risk due to higher fuel and market purchase costs. Partially offsetting these higher operating costs was reduced system balancing costs and lower capital expenditures from the smaller wind investment. (The contribution of the ENS cost as a proportion of total variable costs is less than that reported in the 2007 IRP due to the tiered cost approach applied for this IRP. See the discussion on ENS in Chapter 7 for details.)

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[49] The IRP modeling of wind does not capture the stochastic behavior of wind generation, so related supply reliability risks are not captured in the stochastic analysis.

As expected, with the higher PRM, supply reliability is enhanced as measured by average annual ENS and significant-event LOLP during July. Dividing the incremental portfolio cost by the reduced amount of ENS (487 GWh for 2009-2028) associated with adopting the 15-percent PRM portfolio results in a cost premium of $659/MWh for the ENS reduction.

Table 8.18 – Cost versus Risk for 12% and 15% Planning Reserve Margin Portfolios

				Stochastic Risk, Million $				**Supply Reliability**	
Planning Reserve Margin (%)	**Case**	**CO_2 Tax**	**Stochastic Mean PVRR (Million $)**	**5th Percentile**	**95th Percentile**	**Upper Tail (mean of 5 Highest)**	**Standard Deviation**	**Annual Ave. ENS (GWh/yr)**	**Probability of ENS Event > 25 GWh in July (Annual average)**
12	8	45	39,244	25,594	57,877	70,581	10,534	143.4	19.1%
15	41	45	39,565	26,113	58,265	71,649	10,715	119.1	15.5%
Difference, 15% less 12%			321	518	388	1,068	181	(24)	-3.7%
12	17	70	40,134	27,689	57,738	68,766	9,799	127.1	18.5%
15	42	70	40,166	27,722	57,591	69,029	9,843	98.6	14.3%
Difference, 15% less 12%			32	33	(147)	263	44	(28)	-4.2%
12	24	100	43,496	33,686	57,338	65,939	7,955	72.7	15.5%
15	43	100	43,486	33,736	57,316	65,874	7,936	69.3	15.1%
Difference, 15% less 12%			(10)	50	(22)	(65)	(19)	(3)	-0.4%

Table 8.19 – PVRR Cost Details ($45/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

Cost Component ($ 000)	**12% PRM**	**15% PRM**	**Difference**
	Case 8	**Case 41**	**(Case 41 less 8)**
Variable Cost			
Total Fuel Cost	14,191,867	14,418,506	226,640
Variable O&M Cost	1,222,685	1,241,622	18,937
Total Emission Cost	14,691,301	14,751,942	60,641
Long Term Contracts and Front Office Transactions	8,978,705	9,650,090	671,386
DSM	3,015,434	3,019,019	3,586
Spot Market Balancing			
Sales	(13,089,333)	(13,482,889)	(393,557)
Purchases	3,714,988	3,514,149	(200,839)
Energy Not Served	184,495	152,058	(32,436)
Dump Power	(12,366)	(10,982)	1,384
Reserve Deficiency	73,920	63,886	(10,034)
Total Variable Net Power Costs	**32,971,694**	**33,317,402**	**345,707**
Real Levelized Fixed Costs	**6,272,174**	**6,247,502**	**(24,672)**
Total PVRR	**39,243,869**	**39,564,904**	**321,036**

Table 8.20 – PVRR Cost Details ($70/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

Cost Component ($ 000)	12% PRM Case 17	15% PRM Case 42	Difference (Case 42 less 17)
Variable Cost			
Total Fuel Cost	13,625,227	13,740,869	115,642
Variable O&M Cost	1,204,222	1,215,560	11,339
Total Emission Cost	13,469,668	13,455,115	(14,553)
Long Term Contracts and Front Office Transactions	8,669,522	9,330,643	661,121
DSM	3,186,054	3,180,545	(5,509)
Spot Market Balancing			
Sales	(13,388,006)	(13,854,964)	(466,958)
Purchases	3,546,102	3,284,808	(261,294)
Energy Not Served	168,279	130,139	(38,141)
Dump Power	(21,406)	(19,997)	1,409
Reserve Deficiency	63,344	52,524	(10,820)
Total Variable Net Power Costs	**30,523,005**	**30,515,242**	**(7,764)**
Real Levelized Fixed Costs	**9,610,984**	**9,651,213**	**40,229**
Total PVRR	**40,133,989**	**40,166,454**	**32,465**

Under a $70 CO_2 tax, increasing the PRM results in a similar build pattern as that for the $45 CO_2 tax cases—including the addition of an IC Aero SCCT in 2016—except that System Optimizer removes less wind and increases front office transactions once the peaking resource is added. As can be seen from Table 8.20, the gap in cost and cost risk narrows between the two portfolios, while supply reliability improves slightly. Table 8.21 shows the PVRR cost detail comparison for the two portfolios. Fuel, net system balancing, and emission costs are reduced due to the extra wind included in the 15-percent PRM portfolio and decreased dispatch of thermal units. The cost premium associated with an ENS reduction of 569 GWh drops to $57/MWh.

For the $100 CO_2 tax cases, increasing the PRM to 15 percent results in a larger amount of DSM (125 MW), particularly Class 1 programs, and distributed standby generation (42 MW), and a slight increase in front office transactions. No peaking gas resources were added in either portfolio. As indicated in Table 8.21, costs and cost risk actually decrease slightly due to this resource mix.[50] The supply reliability benefit is negligible, and there is effectively a positive cost benefit for reducing the 69 GWh of ENS.

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[50] The System Optimizer's deterministic PVRR for case 43 was slightly greater than that for case 24: $60.905 billion versus $60.693 billion. The extrinsic (or real option value) of generation units affected by stochastic variation in fuel and market prices is not accounted in the deterministic capacity optimization solutions.

Table 8.21 – PVRR Cost Details ($100/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

Cost Component ($ 000)	12% PRM Case 24	15% PRM Case 43	Difference (Case 43 less 24)
Variable Cost			
Total Fuel Cost	12,231,023	12,159,435	(71,587)
Variable O&M Cost	1,099,133	1,094,393	(4,741)
Total Emission Cost	12,068,839	12,009,121	(59,718)
Long Term Contracts and Front Office Transactions	7,533,865	8,332,267	798,403
DSM	3,342,009	3,443,037	101,028
Spot Market Balancing			
Sales	(13,956,020)	(14,423,822)	(467,802)
Purchases	3,073,137	2,851,243	(221,894)
Energy Not Served	117,336	112,439	(4,897)
Dump Power	(27,096)	(27,081)	15
Reserve Deficiency	35,439	32,499	(2,940)
Total Variable Net Power Costs	**25,517,664**	**25,583,531**	**65,866**
Real Levelized Fixed Costs	**17,978,326**	**17,902,669**	**(75,657)**
Total PVRR	**43,495,990**	**43,486,200**	**(9,790)**

The main conclusions to be drawn from this analysis are as follows:

- With low to moderately high CO_2 tax assumptions (less than $70/ton), planning to a higher PRM results in a significant cost premium for avoiding unserved energy. Whether this cost premium is worth paying is a subjective determination. However, from a stochastic modeling perspective, it is not cost-effective to invest in incremental generating capacity for reserves given that the cost premium for such investment is above the assumed ENS cost.
- In a high CO_2 cost environment, the incremental resources acquired for the larger capacity reserve requirement shifts to low CO_2-emitting options, which is beneficial from an overall stochastic cost perspective. However, the supply reliability improvement from adding these incremental resources appears to reach a point of diminishing returns between $70/ton and $100/ton.

FUEL SOURCE DIVERSITY

Tables 8.22 through 8.24 show the generation shares by fuel type category for selected years (2013, 2020, and 2028) for new resources in each of the 21 portfolios. The generation mix profile for each portfolio changes over time reflecting the availability of conventional and emerging technologies over the 20-year study period.

All the portfolios increase fuel diversity by reducing the generation share of the Company's coal-fired plants. This result is a consequence of the System Optimizer being allowed to select from a diverse range of resource types in response to various price scenarios that in some scenarios make investment in new conventional thermal generation less cost-effective in the future. In this respect, each portfolio has the optimal fuel mix based on it associated input scenario.

While the portfolios increase overall generation fleet fuel and technology diversity, at the same time, concentration of any one fuel or technology for new resource investment has been found to be suboptimal when considering risk and uncertainty. As an example, portfolios for cases 22 and 24 include relatively large investment in wind resources to mitigate correspondingly large CO_2 compliance costs.

Table 8.22 – Generation Shares for New Resources by Fuel Type for 2013

2013 Generation Shares, New Resources (%)			
Case	**Renewable/DSM**	**Natural Gas**	**Market**
1	25%	16%	59%
2	36%	14%	50%
3	70%	8%	23%
5	36%	14%	50%
8	58%	10%	32%
9	36%	14%	50%
10	49%	11%	40%
11	67%	8%	25%
14	76%	6%	17%
17	68%	8%	24%
18	59%	9%	31%
19	65%	9%	26%
20	68%	7%	25%
22	77%	6%	17%
24	77%	6%	17%
25	68%	7%	25%
26	68%	7%	25%
27	73%	6%	21%
29	77%	7%	16%
46	41%	23%	36%
47	33%	26%	41%
Average	58%	11%	31%

Table 8.23 – Generation Shares for New Resources by Fuel Type for 2020

2020 Generation Shares, New Resources (%)				
Case	**Coal**	**Renewable/DSM**	**Natural Gas**	**Market**
1	0%	34%	17%	49%
2	16%	41%	14%	29%
3	11%	75%	3%	11%
5	0%	57%	11%	33%
8	0%	67%	5%	27%
9	0%	58%	10%	32%
10	0%	69%	4%	26%
11	7%	79%	3%	11%
14	7%	81%	3%	10%
17	0%	76%	4%	21%
18	0%	75%	4%	21%
19	0%	76%	3%	20%
20	0%	83%	3%	15%
22	6%	84%	2%	8%

2020 Generation Shares, New Resources (%)				
Case	**Coal**	**Renewable/DSM**	**Natural Gas**	**Market**
24	0%	83%	3%	14%
25	0%	81%	3%	16%
26	0%	82%	3%	15%
27	0%	83%	3%	14%
29	0%	86%	3%	12%
46	14%	50%	11%	25%
47	14%	50%	11%	25%
Average	4%	70%	6%	20%

Table 8.24 – Generation Shares for New Resources by Fuel Type for 2028

2028 Generation Shares, New Resources (%)					
Case	**Coal**	**Nuclear**	**Renewable/DSM**	**Natural Gas**	**Market**
1	0%	0%	34%	11%	55%
2	10%	0%	47%	8%	35%
3	9%	0%	68%	3%	20%
5	5%	0%	50%	7%	38%
8	0%	0%	61%	4%	35%
9	5%	0%	50%	7%	38%
10	0%	0%	63%	3%	34%
11	6%	0%	71%	2%	21%
14	9%	0%	76%	2%	13%
17	9%	0%	61%	2%	28%
18	9%	0%	61%	2%	28%
19	8%	0%	62%	2%	28%
20	6%	11%	62%	2%	19%
22	11%	12%	70%	2%	6%
24	6%	23%	64%	2%	6%
25	7%	0%	69%	2%	22%
26	6%	23%	66%	2%	3%
27	5%	20%	56%	2%	17%
29	9%	21%	66%	2%	2%
46	9%	0%	51%	7%	33%
47	9%	0%	51%	7%	33%
Average	7%	6%	60%	4%	23%

GENERATOR EMISSIONS FOOTPRINT

Carbon Dioxide

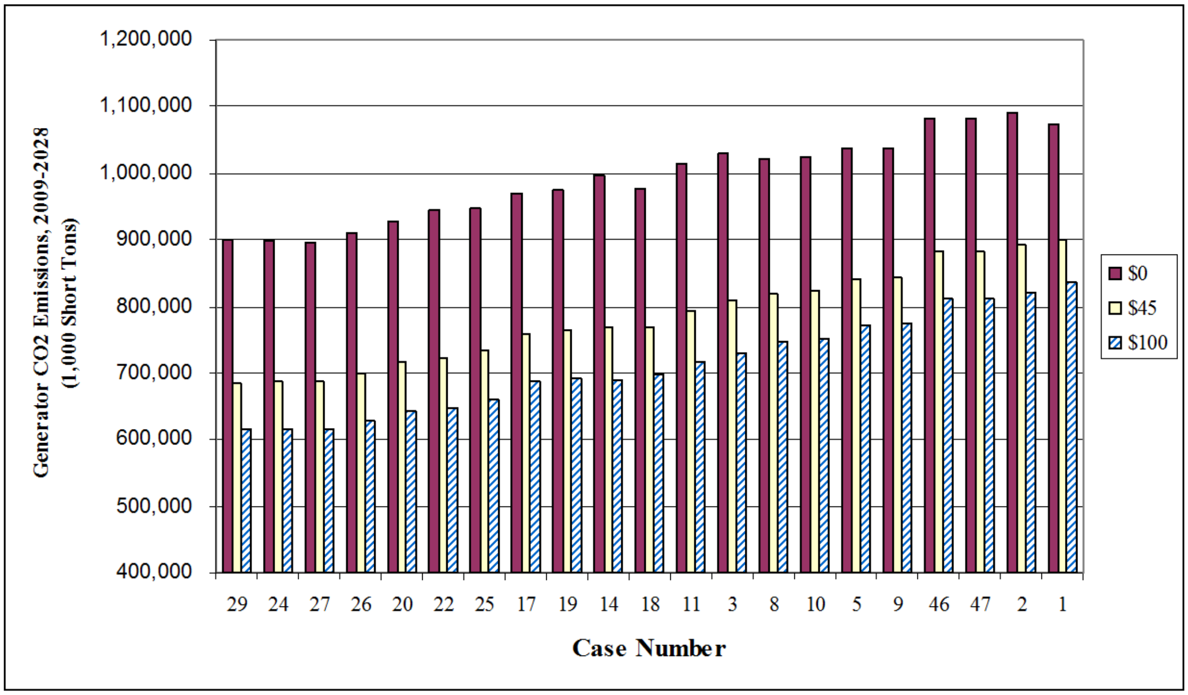
The portfolio cumulative generator CO_2 emissions for the simulation period are presented in Table 8.25 by CO_2 tax level and the average across tax levels. Figure 8.23 shows the emissions footprint in bar chart form by tax level, with portfolios ranked from lowest to highest emissions (left to right) for the $45 tax.

The portfolios with the lowest cumulative CO_2 emissions are those optimized in response to both the $100 CO_2 tax and high gas price scenarios. At the other extreme, portfolios optimized with no CO_2 tax have the highest emissions. A notable exception is the portfolio for case 3. This portfolio was optimized with the high June 2008 gas price scenario, and as a consequence, includes both a pulverized coal plant in 2018 and about 3,900 MW of wind by 2028. This resource combination lowered the CO_2 emissions to less than the amount produced by a number of portfolios optimized with the $45 CO_2 tax; specifically, those for cases 5, 8, 9, and 10.

Table 8.25 – Cumulative Generator Carbon Dioxide Emissions, 2009-2028

Case	**Cumulative Generator CO2 Emissions, 2009-2028 (1,000 Short Tons)**			**Average**
	CO2 Tax Level			
	$0	**$45**	**$100**	
1	1,073,510	899,802	835,943	936,418
2	1,089,942	892,740	821,440	934,707
3	1,028,918	807,954	730,560	855,811
5	1,036,052	841,758	772,358	883,389
8	1,020,539	818,050	746,063	861,551
9	1,037,463	843,569	774,282	885,105
10	1,025,000	823,005	751,041	866,349
11	1,014,089	794,324	716,885	841,766
14	997,347	768,352	688,991	818,230
17	969,127	759,332	687,261	805,240
18	977,559	769,036	696,885	814,493
19	973,843	764,943	692,880	810,555
20	928,315	715,884	643,360	762,520
22	944,887	722,610	647,183	771,560
24	897,912	686,454	615,226	733,197
25	948,159	733,850	660,573	780,861
26	909,892	699,942	628,852	746,228
27	895,656	686,694	616,273	732,874
29	899,919	686,052	615,523	733,831
46	1,080,785	882,033	810,307	924,375
47	1,081,815	883,284	811,541	925,547

Figure 8.23 – Generator Carbon Dioxide Emissions by CO_2 Tax Level



Other Pollutants

Table 8.26 reports for each case portfolio the emissions footprint for sulfur dioxide (SO_2), nitrous oxides (NO_X), and mercury (Hg). On an average basis across each CO_2 tax level, the portfolio for case 24 has the lowest emissions of SO_2. For NO_X, the lowest-emitting portfolio was for case 27, while for mercury, the lowest-emitting portfolio was case 14.

Table 8.26 – Generator Carbon Dioxide Emissions by CO_2 Tax Level

Case	Emission Types and Units			Emission Types and Units			Emission Types and Units		
	SO2	NOx	Hg	SO2	NOx	Hg	SO2	NOx	Hg
	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds
	$0 CO2 Tax			$45 CO2 Tax			$100 CO2 Tax		
1	917	1,214	14,190	735	979	11,665	670	905	10,652
2	922	1,207	14,149	717	947	11,330	647	865	10,244
3	877	1,148	13,648	653	865	10,531	580	776	9,440
5	900	1,191	14,266	698	933	11,591	629	851	10,535
8	883	1,171	13,719	676	908	10,831	606	825	9,752
9	900	1,192	14,281	699	934	11,616	630	853	10,564
10	886	1,175	13,766	679	912	10,898	609	829	9,821
11	869	1,142	13,473	649	863	10,400	577	775	9,322
14	856	1,124	13,329	630	836	10,168	558	746	9,089
17	852	1,143	13,971	642	865	11,356	574	779	10,382
18	859	1,151	14,086	649	874	11,476	580	789	10,495
19	855	1,147	14,037	646	870	11,430	577	784	10,458
20	822	1,102	13,423	610	824	10,831	543	738	9,893
22	825	1,095	13,426	605	807	10,724	537	720	9,780

	Emission Types and Units			Emission Types and Units			Emission Types and Units		
	SO2	NOx	Hg	SO2	NOx	Hg	SO2	NOx	Hg
	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds
Case	$0 CO2 Tax			$45 CO2 Tax			$100 CO2 Tax		
24	796	1,069	13,049	586	793	10,437	521	709	9,526
25	835	1,123	13,720	621	841	11,070	552	754	10,100
26	805	1,081	13,181	597	806	10,605	532	722	9,697
27	795	1,067	12,954	588	793	10,403	523	710	9,507
29	799	1,072	13,092	590	792	10,462	526	710	9,562
46	917	1,202	14,091	710	941	11,241	639	857	10,153
47	918	1,203	14,103	712	942	11,264	641	858	10,177

TOP-PERFORMING PORTFOLIO SELECTION

Chapter 7 outlined the portfolio preference scoring approach for selecting the top portfolios. Preference-scoring grids were prepared for 12 expected value CO_2 tax levels, ranging from $15 to $70 at $5 increments. Table 8.27 shows the expected value CO_2 tax levels and associated probabilities. Stochastic cost results for the three CO_2 tax production cost simulations were weighted with these probabilities. These probability-weighted results are reported in Appendix B, and include risk-adjusted PVRR, customer rate impact, CO_2 cost exposure, upper-tail mean PVRR, and standard deviation of production costs. The 12 preference-scoring grids are also reported in Appendix B. A preference-scoring grid sample—for the $45 expected value CO_2 tax— is shown as Table 8.28.

Table 8.27 – Probability Weights for Calculating Expected Value CO_2 Tax Levels

Expected Value CO2 Tax	Probability (%)		
	$0/ton	$45/ton	$100/ton
$15	66	34	0
$20	55	45	0
$25	45	55	0
$30	40	55	5
$35	35	55	10
$40	30	55	15
$45	25	55	20
$50	20	55	25
$55	15	55	30
$60	10	55	35
$65	5	55	40
$70	0	55	45

Table 8.28 – Measure Rankings and Preference Scores, $45/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1	2.7	2.0	1.0	2.7	10.0	10.0	10	**3.6**	**3.2**
2	1.6	2.1	1.3	1.6	7.2	3.9	2.1	**2.1**	**1.2**
3	2.8	3.2	6.7	2.8	2.8	2.0	2.1	**3.0**	**2.4**
5	1.3	1.1	1.6	1.3	7.6	5.2	4.6	**2.0**	**1.0**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**2.0**	**1.1**
9	1.5	1.0	1.8	1.5	7.6	5.9	5.8	**2.2**	**1.3**
10	2.1	2.1	3.8	2.1	6.2	5.5	8.9	**2.9**	**2.2**
11	3.3	1.4	7.1	3.3	2.7	2.2	2.9	**3.0**	**2.4**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.9**	**4.9**
17	2.2	1.5	6.6	2.2	4.5	4.2	6.6	**2.7**	**2.0**
18	2.3	2.5	5.4	2.3	4.9	4.4	7.8	**3.0**	**2.4**
19	2.8	2.6	6.4	2.8	4.7	4.4	7.1	**3.3**	**2.8**
20	4.9	3.4	8.0	4.9	2.1	2.1	4.3	**4.4**	**4.3**
22	6.9	6.7	10.0	6.9	1.1	1.0	1.0	**6.1**	**6.6**
24	6.8	7.8	9.6	6.8	1.2	1.1	1.5	**6.3**	**6.9**
25	3.8	3.3	8.0	3.8	3.1	3.1	5.1	**3.9**	**3.6**
26	6.8	7.4	9.6	6.8	1.6	1.5	3.4	**6.4**	**6.9**
27	6.8	6.2	9.6	6.8	1.1	1.3	2.6	**6.1**	**6.5**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.7	3.2	2.7	3.7	6.9	4.8	9.0	**4.1**	**3.8**
47	2.4	2.4	1.5	2.4	7.1	4.5	6.9	**2.9**	**2.3**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

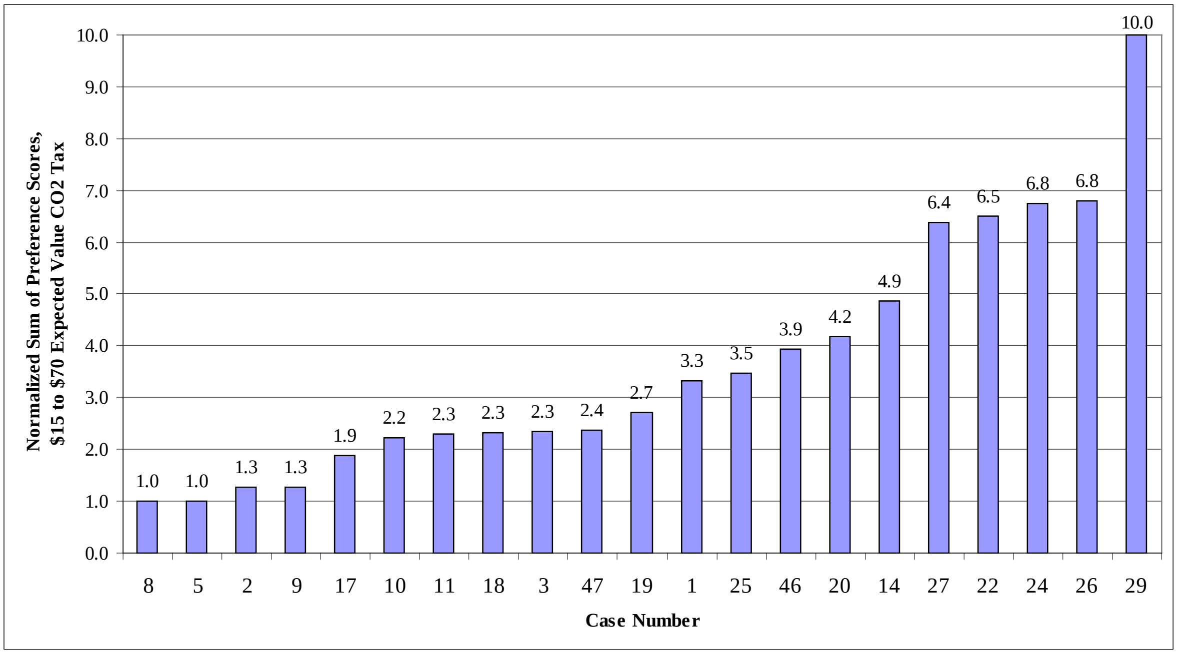
Table 8.29 reports the portfolio preference scores for each of the 12 expected value CO_2 tax levels. When summing the normalized preference scores across the expected value CO_2 tax levels, the portfolios for cases 5 and 8 have the best scores, followed by cases 9 and 2. (These portfolios are shown highlighted in the table.) These four portfolios were therefore selected as the candidates for preferred portfolio selection.

Table 8.29 – Portfolio Preference Scores

	Expected Value CO2 Tax													
Case	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70	Rank Sum	Normalized Score
1	2.40	2.43	2.47	2.56	2.67	2.82	3.15	3.61	4.19	4.88	5.71	6.81	43.7	3.33
2	1.00	1.00	1.00	1.00	1.00	1.00	1.19	1.50	1.93	2.43	3.03	3.96	20.0	1.26
3	3.14	3.07	3.00	2.86	2.69	2.49	2.41	2.39	2.44	2.49	2.56	2.90	32.4	2.35
5	1.63	1.53	1.43	1.31	1.17	1.01	1.00	1.09	1.27	1.49	1.76	2.37	17.0	1.00
8	2.21	2.06	1.92	1.72	1.48	1.21	1.07	1.00	1.00	1.00	1.02	1.35	17.0	1.00
9	1.83	1.74	1.64	1.53	1.40	1.25	1.25	1.35	1.54	1.77	2.06	2.67	20.0	1.26
10	2.98	2.86	2.75	2.61	2.45	2.28	2.23	2.26	2.36	2.47	2.63	3.07	30.9	2.22
11	3.51	3.39	3.27	3.07	2.85	2.56	2.38	2.25	2.17	2.09	2.01	2.20	31.8	2.29
14	5.46	5.42	5.38	5.27	5.15	4.99	4.91	4.88	4.88	4.88	4.89	5.08	61.2	4.86
17	3.69	3.49	3.29	3.01	2.68	2.30	2.01	1.75	1.53	1.28	1.00	1.00	27.0	1.87
18	3.81	3.64	3.46	3.23	2.96	2.64	2.43	2.25	2.12	1.96	1.80	1.90	32.2	2.33
19	4.18	4.02	3.85	3.62	3.35	3.04	2.82	2.64	2.49	2.33	2.15	2.22	36.7	2.72
20	5.93	5.75	5.56	5.30	5.00	4.64	4.32	4.02	3.71	3.37	2.99	2.81	53.4	4.18
22	7.24	7.18	7.11	7.00	6.87	6.70	6.58	6.47	6.37	6.26	6.14	6.13	80.1	6.51
24	7.91	7.79	7.67	7.51	7.31	7.08	6.87	6.65	6.43	6.17	5.87	5.67	82.9	6.76
25	5.15	4.97	4.79	4.54	4.24	3.89	3.60	3.33	3.08	2.79	2.47	2.37	45.2	3.46
26	7.80	7.69	7.58	7.43	7.26	7.06	6.89	6.72	6.55	6.35	6.12	6.00	83.5	6.81
27	7.72	7.58	7.44	7.25	7.02	6.75	6.50	6.24	5.97	5.67	5.32	5.10	78.6	6.38
29	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	120.0	10.00
46	3.01	3.07	3.14	3.24	3.35	3.49	3.80	4.22	4.75	5.38	6.13	7.13	50.7	3.94
47	1.91	1.93	1.95	1.97	2.01	2.05	2.27	2.60	3.06	3.58	4.22	5.15	32.7	2.37

Figure 8.24 shows the portfolio preference scores from Table 8.36 sorted from best to worst.

Figure 8.24 – Portfolio Preference Scores, sorted from Best to Worst



Sensitivity of Portfolio Preference Rankings to Measure Importance Weights

To test the sensitivity of the preference scores to changes in measure importance weights—particularly for the top-performing portfolios—PacifiCorp constructed a preference-scoring grid for the expected value $45 CO_2 tax level with an alternate set of weights. The alternate weights reflect a combination of comments and recommendations made by participants at PacifiCorp's February 2, 2009 public meeting, and place more importance on risk-adjusted PVRR and CO_2 cost risk, but none on capital costs. These alternative weights are shown in Table 8.30.

Table 8.30 – Alternate Measure Importance Weights

Measures	Weight
Cost	
Risk-adjusted PVRR	50%
Customer Rate Impact	10%
Capital Cost for 2009-2018	0%
Risk	
CO_2 Cost Exposure	25%
Production Cost Standard Deviation	5%
Average annual ENS	5%
Average Annual Probability of ENS events for July exceeding 25 GWh	5%

The resulting measure rankings and preference scores based on these alternate weightings are reported in Table 8.31. The alternate weights result in changes to scores of no more than two-tenths of a point. The score for case 8 registers a slight improvement relative to the score for case 5, resulting in a switch in ranking. However, portfolios 8, 5, 2, and 9 remain the top ranked under both weighting schemes. Based on this result, PacifiCorp concludes that the top-performing portfolios are robust choices given variations in the measure weighting schemes.

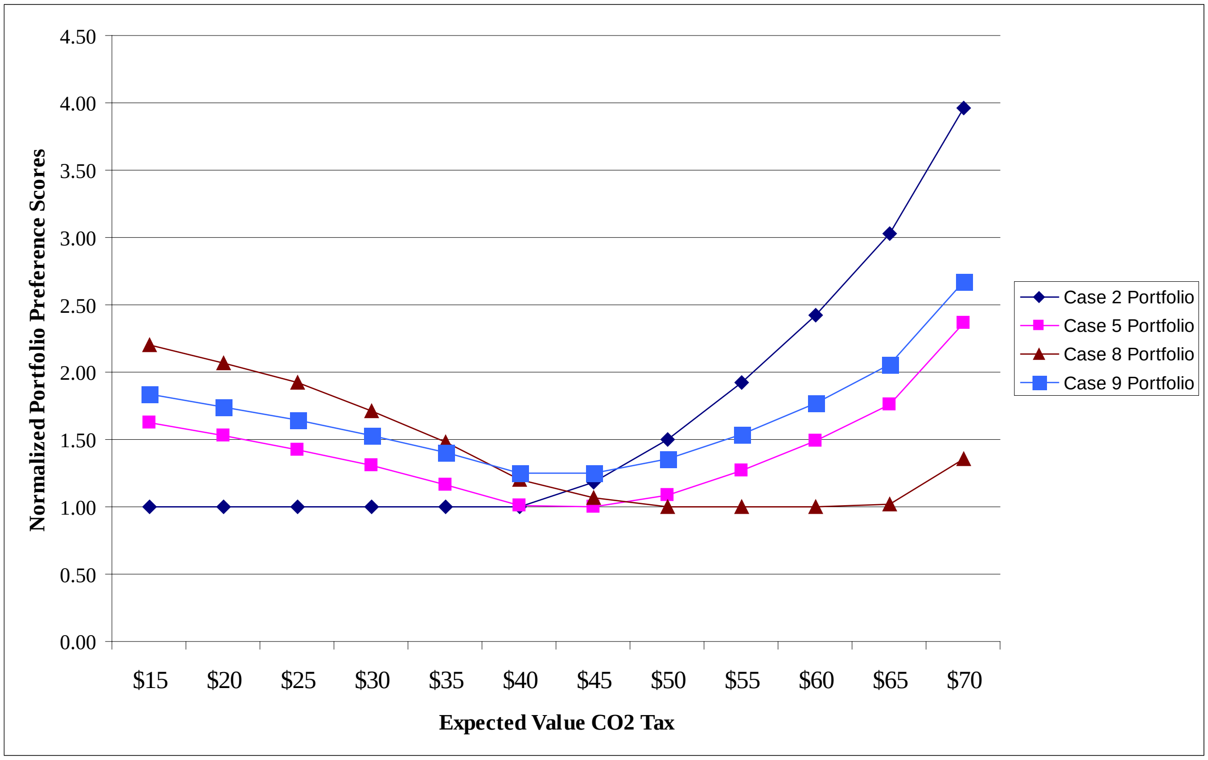
Table 8.31 – Measure Rankings and Preference Scores with Alternative Measure Importance Weights, $45/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**		
1	2.7	2.0	1.0	2.7	10.0	10.0	10	**3.7**	**3.5**
2	1.6	2.1	1.3	1.6	7.2	3.9	2.1	**2.1**	**1.3**
3	2.8	3.2	6.7	2.8	2.8	2.0	2.1	**2.8**	**2.3**
5	1.3	1.1	1.6	1.3	7.6	5.2	4.6	**2.0**	**1.2**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**1.8**	**1.0**
9	1.5	1.0	1.8	1.5	7.6	5.9	5.8	**2.2**	**1.5**
10	2.1	2.1	3.8	2.1	6.2	5.5	8.9	**2.8**	**2.3**
11	3.3	1.4	7.1	3.3	2.7	2.2	2.9	**3.0**	**2.5**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.7**	**4.8**
17	2.2	1.5	6.6	2.2	4.5	4.2	6.6	**2.6**	**2.0**
18	2.3	2.5	5.4	2.3	4.9	4.4	7.8	**2.9**	**2.4**
19	2.8	2.6	6.4	2.8	4.7	4.4	7.1	**3.2**	**2.8**
20	4.9	3.4	8.0	4.9	2.1	2.1	4.3	**4.4**	**4.4**
22	6.9	6.7	10.0	6.9	1.1	1.0	1.0	**6.0**	**6.5**
24	6.8	7.8	9.6	6.8	1.2	1.1	1.5	**6.1**	**6.6**
25	3.8	3.3	8.0	3.8	3.1	3.1	5.1	**3.8**	**3.5**
26	6.8	7.4	9.6	6.8	1.6	1.5	3.4	**6.2**	**6.7**
27	6.8	6.2	9.6	6.8	1.1	1.3	2.6	**6.0**	**6.4**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.7	3.2	2.7	3.7	6.9	4.8	9.0	**4.2**	**4.1**
47	2.4	2.4	1.5	2.4	7.1	4.5	6.9	**3.0**	**2.5**

Importance Weights	**50%**	**10%**	**0%**	**25%**	**5%**	**5%**	**5%**

As indicated above, the portfolios developed under cases 2, 5, 8, and 9 performed the best according to the final preference scores. For selecting the preferred portfolio, of interest is how the preference scores for these portfolios vary across the CO_2 tax levels. Figure 8.25 shows the scores at each expected value CO_2 tax level. The case 2 portfolio scores the best with tax levels below $40, while the case 8 portfolio scores the best with tax levels at $50 and above. Case 5 appears to represent the "least-regrets" portfolio with respect to the range of preference scores, avoiding the highest scores like the case 2 and 8 portfolios, and always dominating the case 9 portfolio.

Figure 8.25 – Preference Scores by Expected Value CO_2 Tax, Top-performing Portfolios



Based on the preference scores and the analysis above, PacifiCorp dropped cases 2 and 9 from further consideration as the preferred portfolio. A discussion of the comparative advantages, disadvantages, and risks for the two remaining portfolios is provided below.

Case 5 versus Case 8 Portfolio Assessment

Both case 5 and case 8 are equally strong contenders to be the 2008 IRP preferred portfolio. The main difference between the two portfolios is that case 8 includes 1,150 MW more wind in the first 10 years (600 MW more overall), and lacks a gas peaking resource in 2016. Case 5 also includes more east-side front office transactions in the first 10 years than case 8.

The assumed CO_2 cost is the key determinant for overall portfolio performance: case 8 outperforms case 5 with CO_2 taxes at $45 and above, but the reverse is true with CO_2 taxes below $45. Noteworthy is that case 5 out-performs case 8 on customer rate impact for all CO_2 tax levels.

In terms of relative advantages independent of the operational cost impact of a CO_2 price, case 5 has a smaller capital cost (by $2.2 billion), as well as a lower probability of a major ENS event during the system peak month. In contrast, case 8 has a lower upper-tail cost and upper-tail ENS, reflecting the variable operating cost savings benefits of the additional wind and its selected location in load areas that exhibit relatively higher ENS.

A disadvantage for case 8 is the amount of wind investment in the first 10 years, which reaches 2,600 MW. The average annual capacity added for 2012 through 2018 exceeds 300 MW, which is a concern from procurement, rate impact, construction project management, and operational perspectives. This wind is not needed for RPS compliance purposes, and its economic desirability hinges on continuation of a production tax credit (or comparable financial incentive), a significant CO_2 cost penalty benefiting clean energy alternatives, and a robust market for sales of excess energy, particularly during off-peak hours. On the other hand, the incremental wind provides added price hedge benefits due to the lack of fuel costs and exposure to future CO_2 compliance costs. The respective wind expansion patterns for cases 5 and 8 suggest that the optimal wind strategy is to identify a wind capacity floor and upper value that are updated as aspects of future federal CO_2 compliance cost and renewable energy policies becomes clearer. This strategy takes advantage of the relatively short development lead-time and modular construction of wind resources. PacifiCorp's action plan discusses this wind strategy in more detail.

Both portfolios have heavier reliance on market purchases relative to most other portfolios, which increases the risk of a high-end cost outcome. Case 8 does better than case 5, due to more renewable resources and east-side Class 2 DSM, but both appear in the bottom quartile of ranking results for upper-tail risk measures. This higher tail risk must be evaluated in the context of the timing of when the tail risk is most pronounced, and other risks that these portfolios help mitigate. For example, Table 8.32 compares the 95th percentile PVRRs for the case 5, 8 and 22 portfolios given a 10-year span (2009-2018) and 20-year span (2009-2028). The case 22 portfolio ranks at the top for upper-tail mean PVRR.

Table 8.32 – Short- and Long-term 95th Percentile PVRR Comparisons

Case	95th Percentile, Million $ $45/ton CO2 Tax	
	10-Year 2009-2018	20-Year 2009-2028
5	24,832	59,619
8	23,952	57,877
22	24,453	57,320
Case 5 less 22	379	2,299
Case 8 less 22	(501)	558

As the comparison shows, differences in upper-tail mean PVRR are significantly lower under the 10-year view. Case 8 actually performs better than case 22, owing primarily to the high capital costs associated with a pulverized coal plant and 4,500 MW of wind included in case 22. The portfolios that do well on the 20-year upper-tail cost measures rely on large amounts of wind resources, as well as base-load resources such as conventional pulverized coal and nuclear in the out-years—resources with their own significant risks. This comparison again illustrates the trade-off between expected costs and high-end cost risk.

As emphasized in PacifiCorp's 2007 IRP, PacifiCorp believes that firm market purchases benefit the preferred portfolio by increasing planning flexibility and resource diversity at a time of considerable regulatory uncertainty. The current economic recession, coupled with the Company's need for grid infrastructure and clean air investments, magnifies the importance of such flexibility for maintaining affordable customer rates. Nevertheless, PacifiCorp recognizes the risks associated with market reliance, and has in place a price hedging strategy to mitigate these risks. A description of PacifiCorp's price hedging strategy is provided in Chapter 9.

Regarding fuel source diversity, the case 8 portfolio has a greater proportion of renewable generation—and generation reduction in the case of Class 2 DSM—than for case 5, particularly in the near term. On the other hand, case 5 has a greater share of gas generation, and for the first 10 years, more reliance on generation from market purchases. By 2028, the generation mix for the two portfolios look similar. The significant difference is that case 5 includes a clean coal resource in 2025, while case 8 depends on much earlier wind investment to meet CO_2 and RPS compliance requirements.

Scenario Risk Assessment

Risk Scenario Development

In accordance with the Public Service Commission of Utah's acknowledgement order for PacifiCorp's last IRP, the Company followed the Commission's instruction to "examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions".[51] PacifiCorp selected the three top-performing portfolios—cases 5, 8, and 9—for this analysis (Case 2 had a. were fixed in the System Optimizer capacity expansion model. The model was then executed to solve for the deterministic PVRR under each selected input scenario. The input scenarios consisted of the following case assumptions:

- Medium load growth forecast
- June 2008 forward price curves and high/low variations
- Varying CO_2 tax levels: \$0, \$45, \$70, and \$100

The resulting ten risk scenarios, along with the represented cases, are listed in Table 8.33. A total of 30 deterministic PVRRs therefore represent the outcome of the scenario risk modeling.

Table 8.33 – Scenario Risk Case Definitions

Risk Scenario Number	Case Number	CO_2 tax ($/ton)	Gas Price Forecast	Load Growth Scenario
1	1	$0	Low	Medium
2	2	$0	Medium	Medium
3	3	$0	High	Medium
4	5	$45	Low	Medium
5	8	$45	Medium	Medium
6	14	$45	High	Medium
7	17	$70	Medium	Medium
8	22	$70	High	Medium
9	24	$100	Medium	Medium

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[51] Public Service Commission of Utah, Report and Order, In the Matter of the PacifiCorp 2006 Integrated Resource Plan, Docket No. 07-2035-01, February 6, 2008, p. 40.

Risk Scenario Number	Case Number	CO_2 tax ($/ton)	Gas Price Forecast	Load Growth Scenario
10	29	$100	High	Medium

The analysis did not include alternative load growth scenarios because the portfolios were developed with the same load growth forecast. Therefore, applying alternative load forecasts would have no value for cost comparison purposes. The selection of only the June 2008 price forecast assumptions reflects a practical decision to help limit the number of additional model runs to a manageable number.

Risk Scenario Modeling Results

Table 8.34 shows the deterministic PVRR results for the 30 System Optimizer runs, along with the PVRR average and the standard deviation for each portfolio across the risk scenarios. The portfolio for case 8 has both the lowest PVRR and the smallest PVRR variability across the risk scenarios. The case 8 and 5 portfolios are nearly equal with respect to both PVRR average and standard deviation, owing to the similarity of the portfolios.

Table 8.34 – Scenario Risk PVRR Results

Risk Scenario Number	Case	Deterministic PVRR (Million 2008$)		
		Portfolio Case 5	Portfolio Case 8	Portfolio Case 9
1	1	21,025	21,972	21,048
2	2	22,176	22,305	22,188
3	3	22,550	21,288	22,481
4	5	40,542	40,730	40,542
5	8	41,691	41,389	41,672
6	14	44,243	42,430	44,146
7	17	52,533	51,782	52,489
8	22	55,159	53,144	55,049
9	24	64,853	63,379	64,768
10	29	65,123	62,913	64,915
Average		42,990	42,133	42,930
Standard Deviation		15,968	15,278	15,920

Table 8.35 reports the portfolio PVRR rankings for each risk scenario. Case 8 ranks first on the basis of having the lowest rank sum (16). Case 9 comes in second with a rank sum of 19, followed by case 5 with a rank sum of 24.

Table 8.35 – Portfolio PVRR Rankings

Risk Scenario Number	Case	Portfolio Rankings based on Deterministic PVRR		
		Portfolio Case 5	Portfolio Case 8	Portfolio Case 9
1	1	1	3	2
2	2	1	3	2

Risk Scenario Number	Case	Portfolio Rankings based on Deterministic PVRR		
		Portfolio Case 5	Portfolio Case 8	Portfolio Case 9
3	3	3	1	2
4	5	1	3	1
5	8	3	1	2
6	14	3	1	2
7	17	3	1	2
8	22	3	1	2
9	24	3	1	2
10	29	3	1	2
Rank Sum		24	16	19

Table 8.36 shows differences between the original deterministic PVRR and those obtained for the risk scenario runs.[52]

Table 8.36 – PVRR Differences, Portfolio Development Case less Risk Scenario Results

Risk Scenario Number	Case	Deterministic PVRR (Million 2008$)		
		Portfolio Case 5	Portfolio Case 8	Portfolio Case 9
Original PVRR		40,526	41,372	40,204
1	1	(19,501)	(19,400)	(19,156)
2	2	(18,350)	(19,067)	(18,016)
3	3	(17,976)	(20,084)	(17,723)
4	5	16	(642)	338
5	8	1,165	17	1,468
6	14	3,717	1,058	3,942
7	17	12,007	10,410	12,285
8	22	14,633	11,772	14,845
9	24	24,327	22,007	24,564
10	29	24,597	21,541	24,711

These results indicate that Portfolio 5 performed best in low gas/low CO_2 tax scenarios and performed worst in high gas price and high CO_2 tax cases. Portfolio 8 performed best under the medium/high gas price and medium/high CO_2 tax scenarios, but performed worst in low gas/low CO_2 scenarios.

Conclusions

The scenario risk assessment yielded findings similar to the stochastic mean cost analysis regarding the top-performing portfolio, case 8. However, case 9 performed slightly ahead of case 5 in the scenario risk analysis, whereas case 5 performed ahead of case 9 under the stochastic mean cost analysis. Given this outcome, the question is whether the risk scenario analysis, as formu-

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[52] Fixing of resources in System Optimizer for the risk scenario runs entailed rounding capacity values of the smaller resources, such as class 2 DSM amounts by topology bubble, price tier, and year. The result was a small PVRR difference with respect to the PVRR obtained in the original portfolio development run.

lated above, provides any added value for preferred portfolio selection over that provided by the stochastic analysis. PacifiCorp concludes that it does not. The reasons are as follows. First, the stochastic Monte Carlo simulations provide 100 combinations of input invariables, accounting for variable correlations. The scenario risk assessment is essentially a manually formulated and limited version of the Monte Carlo simulation. It is impractical to emulate this range of input variability using System Optimizer or the Planning and Risk model in deterministic mode.

Second, the scenario risk assessment introduces a confounding aspect to the preferred portfolio selection process given the situation where the analysis yields performance conclusions contradictory to those obtained from the stochastic analysis—such as with the case 5 and 9 portfolios.

In summary, PacifiCorp believes that the stochastic risk analysis is sufficient for exploring portfolio cost outcomes given a range of input assumptions reflecting uncertainty and risk. The only value that the scenario risk assessment provides is to confirm the degree that stochastic and deterministic costs are consistent for portfolio ranking purposes. On the other hand, the Company finds value with subjecting a portfolio to resource-specific scenarios as part of the acquisition path analysis, and using System Optimizer to determine the optimal resource mix under those alternate resource assumptions.

PORTFOLIO IMPACT OF THE 2012 GAS RESOURCE DEFERRAL DECISION

Based on the portfolio preference scores and consideration of relative resource risks, the Company would have chosen the case 5 portfolio as the basis for its preferred portfolio. However, due to the Company's February 2009 decision to terminate the construction contract for the Lake Side II CCCT resource, PacifiCorp conducted additional portfolio analysis to determine a revised preferred portfolio that takes this decision into account, as well as new transmission and market assumptions that supported that decision.

PacifiCorp conducted two types of portfolio studies reflecting the removal of Lake Side II as a planned resource in 2012. The first type involved fixing a combined-cycle gas plant in 2014 and running System Optimizer to select other resources using the case 5 input assumptions. Two portfolios were created: one had a 570 MW (July capacity) wet-cooled CCCT located at the Lake Side site in Utah North, while the second had a 536 MW dry-cooled CCCT located in the Currant Creek site. This was followed by stochastic production cost modeling runs using the PaR model with \$0, \$45, and \$100 CO_2 tax levels. These two portfolios reflect a CCCT deferral strategy that assumes, conservatively, that CCCT capital costs do not change from the generic values assumed for the 2008 IRP, after adjusting for inflation.[53] The rationale for fixing CCCTs in System Optimizer is that this model does not account for resource optionality and reserve holding value captured through stochastic production cost modeling, and tends to favor SCCTs over CCCTs for meeting capacity planning reserve margins as a result.

The second portfolio study type consisted of the removal of the Lake Side II plant in the top eight portfolios selected on the basis of the preference scores (Table 8.36), and having System

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[53] PacifiCorp expects that lower commodity costs and the effects of the world-wide economic downturn should eventually start to impact plant construction prices. However, the Company did not see price reductions in the bids received in response to its 2008 All-Source RFP issued in October 2008.

Optimizer select the portfolios to fill the resource gap using the case definitions associated with these portfolios. Stochastic production cost simulations with multiple CO_2 tax levels were also conducted for these 10 portfolios.

The portfolios modeled without Lake Side II reflect a number of assumption changes documented in Chapters 6 and 7. Table 8.37 profiles the 10 portfolios and the associated input assumptions.

Table 8.37 – Additional Portfolios Modeled to Support a 2012 Gas Resource Deferral Strategy

Portfolio Name	Case Definition Used	Additional Fixed Resources	Common Assumption Changes
2B	2	None	• Lake Side II CCCT removed as a planned resource • West Main/West Main to Yakima topology updates (See Figure 7.2) • Mona to Utah South topology update (See Figure 7.2) • Mid-Columbia market depth updates for 2012 and 2013 (See Table 6.22) • Mona market depth updates for 2012 and 2013, including Nevada Utah Border (See Table 6.22)
5B	5	None	
5B_CCCT_Dry	5	Dry-cooled CCCT fixed in 2014	
5B_CCCT_Wet	5	Wet-cooled CCCT fixed in 2014	
8B	8	None	
9B	9	None	
10B	10	None	
17B	17	None	
18B	18	None	
47B	47	None	

PacifiCorp developed a full set of performance measures for these portfolios and ranked them using the same preference-scoring scheme applied for the original 21 portfolios. These additional portfolios are shown in Appendix A. The stochastic performance measures are reported in Appendix B.

Table 8.38 compares the cumulative nameplate capacities by major resource type for the original and "B series" portfolios. The B series portfolios include more front office transaction and energy efficiency program capacity than their original portfolio counterparts, and—with the exception of the two fixed CCCT portfolios (5B_CCCT_Dry and 5B_CCCT_Dry)—include more IC Aero SCCT capacity. On the other hand, just four of the 10 portfolios include more wind capacity (2B, 10B, 17B, and 47B), while two portfolios have less wind than the original portfolios (8B and 18B). Portfolio tables showing the resource capacity differences between the ten B series portfolios and the corresponding originals are included in Appendix A.

Table 8.38 – Resource Capacity Comparisons, Original and B Series Portfolios

	Cumulative Nameplate Capacity for 2009-2028 (MW) by Resource Type						
Case	**Wind**	**CCCT**	**IC Aero SCCT**	**FOT [1/]**	**DSM, Class 2**	**Dist Gen [2/]**	**Clean Coal Retrofit**
2	1,204	607	261	646	1,815	50	0
2B	1,863	0	548	775	1,866	92	0
5	1,863	607	261	691	1,835	50	346

Case	Cumulative Nameplate Capacity for 2009-2028 (MW) by Resource Type						
	Wind	CCCT	IC Aero SCCT	FOT [1/]	DSM, Class 2	Dist Gen [2/]	Clean Coal Retrofit
5B	1,863	0	391	829	1,896	132	0
5B_CCCT_Dry	1,863	536	261	821	1,839	78	346
5B_CCCT_Wet	1,863	570	261	820	1,838	50	346
8	2,663	607	0	663	1,942	88	0
8B	2,563	0	261	811	1,989	129	0
9	1,863	607	261	690	1,834	50	346
9B	1,863	0	391	829	1,893	132	0
10	2,863	607	0	679	1,936	57	0
10B	2,952	0	261	820	1,985	127	0
17	4,163	607	0	613	2,020	50	346
17B	4,363	0	261	796	2,063	127	346
18	4,163	607	0	640	1,974	50	346
18B	3,863	0	261	808	2,023	127	346
47	1,607	607	174	646	1,822	92	0
47B	2,383	0	609	797	1,855	92	0

[1/] Annual average front office transactions capacity for 2009-2018 shown.

[2/] Distributed generation consists of customer standby generation and combined heat and power facilities.

General findings for this additional portfolio analysis are as follows.

- The combination of revised input assumptions and deferral of a 2012 gas resource resulted in lower PVRRs compared with those reported for the original portfolios. For example, as shown in Table 8.39, the stochastic mean PVRR of portfolio 5B (averaged across the three CO_2 tax simulations) is $570 million less than the PVRR for the original case 5 portfolio.[54]

- The portfolio with a wet-cooled CCCT located at the Lake Side II site ("5B_CCCT Wet") had the lowest risk-adjusted PVRR, CO_2 cost exposure, and rate impact (Table 8.40). The other two case 5 portfolios ranked second and third.

- The wet-cooled CCCT deferral portfolio also had the best overall preference score, ranking at the top for expected value CO_2 tax levels of $20 through $60. Table 8.41 presents the portfolio preference scores for CO_2 tax expected values from $15 to $70.

- The three portfolios developed with the case 5 input assumptions had the highest preference scores (Table 8.41). This portfolio analysis strengthens the assertion that case 5 is relatively robust at producing the optimal portfolios on the basis of overall preference scoring.

- Fixing a CCCT in 2014 rather than allowing System Optimizer to fully optimize resource selection resulted in improved stochastic costs. For example, fixing a wet-cooled CCCT in 2014 yielded a $115 million improvement in risk-adjusted PVRR (averaged across the $0,

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[54] The PVRRs for the original case 5 portfolio reported in Table 8.41 are adjusted to include 2012 CCCT capital costs for comparability with the gas resource deferral portfolios. Because the Lake Side II CCCT was treated as an existing resource in all the original portfolios, associated capital costs were not included in the PVRR calculations.

$45, and $100 CO_2 tax simulations) relative to portfolio 5B, which has no CCCT. Fixing a dry-cooled CCCT in 2014 resulted in a $51 million risk-adjusted PVRR improvement.

- The tail risk (upper-tail mean PVRR) for the B series portfolios is lower than that for the original portfolios, accounting for the capital cost of the Lake Side II resource (See footnote no 49). This is generally due to more wind, DSM, and distributed generation in these new portfolios. The two CCCT deferral portfolios had the highest upper-tail risk and production cost standard deviation among the B series portfolios. Figure 8.26 is a scatter-plot graph of the stochastic mean PVRR versus upper-tail mean PVRR for the three CO_2 tax levels. (Table B.23 in the appendix volume shows portfolio ranking results for an alternate importance weighting scheme that includes the upper-tail mean PVRR as a performance measure with a relatively large importance weight: 20%.)

Table 8.39 – Stochastic Mean PVRR for 2012 Gas Resource Deferral Strategy Portfolios

	CO2 Tax Level				
Case	**$0/Ton**	**$45/Ton**	**$100/Ton**	**Average**	**Rank**
2B	22,126	40,062	60,448	40,879	8
5B	22,554	39,452	58,664	40,224	3
5B_CCCT_Dry	22,462	39,369	58,751	40,194	2
5B_CCCT_Wet	22,457	39,315	58,639	40,137	1
8B	23,402	39,673	57,809	40,295	4
9B	22,778	39,725	59,031	40,511	5
10B	23,921	40,261	58,542	40,908	8
17B	25,569	40,539	56,798	40,968	9
18B	25,102	40,353	57,136	40,864	6
47B	22,658	40,507	60,872	41,346	10
5 [1/]	23,075	39,947	59,358	40,794	

[1/] The PVRRs for the original case 5 portfolio are adjusted to include 2012 CCCT capital costs for comparability with the gas resource deferral portfolios.

Table 8.40 – Measure Rankings and Preference Scores for 2012 Gas Resource Deferral Strategy Portfolios, $45/ton Expected-value CO_2 Tax

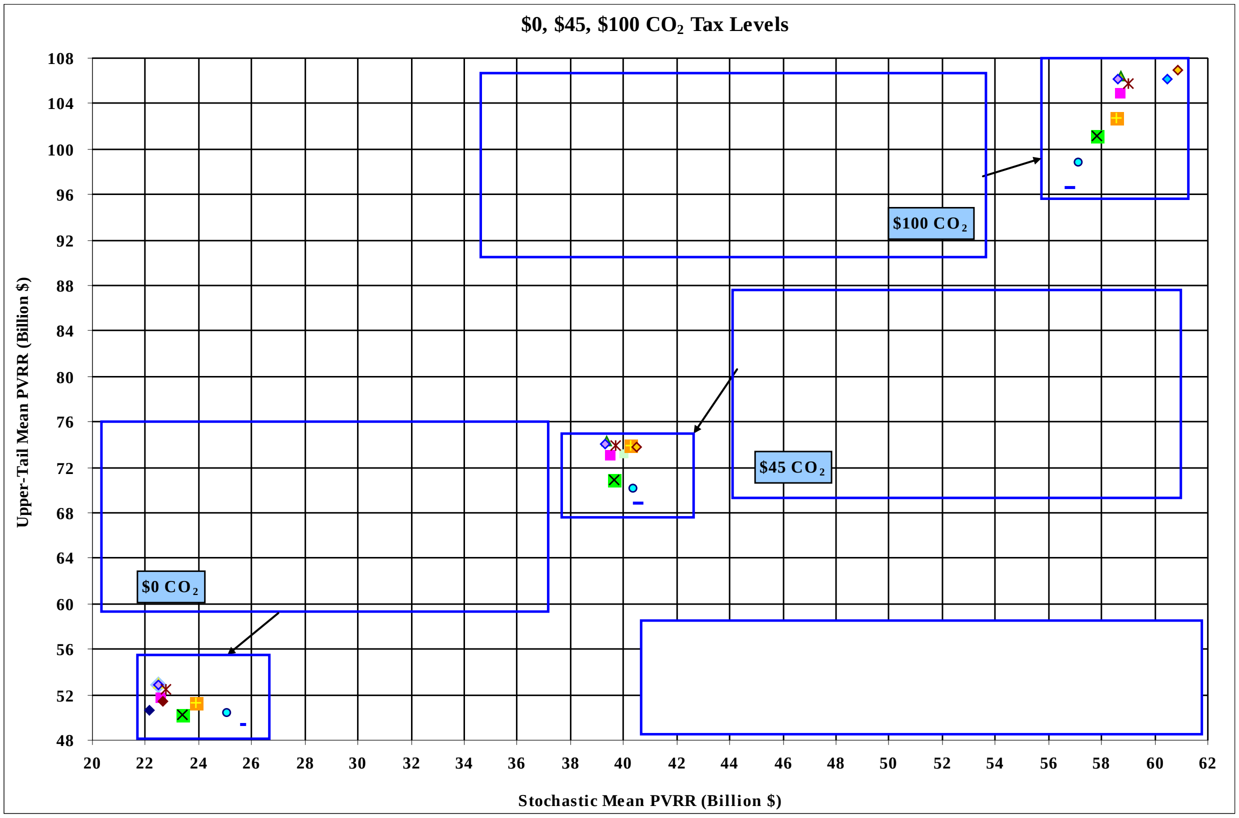
	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	6.5	8.9	1.0	6.0	8.0	1.2	1	**5.8**	**6.7**
5B	2.0	2.7	3.0	3.0	8.5	7.5	6.3	**2.7**	**2.8**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.8**	**1.7**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	2.9	4.8	6.4	4.0	5.2	4.9	4.5	**3.7**	**4.0**
9B	4.2	2.3	3.2	5.0	9.0	10.0	10.0	**4.3**	**4.8**
10B	7.8	10.0	5.7	7.0	5.8	5.3	6.8	**7.5**	**8.9**
17B	8.8	8.9	10.0	9.0	1.0	1.1	2.2	**7.8**	**9.3**
18B	7.9	8.1	8.2	8.0	2.9	3.3	2.2	**7.1**	**8.4**
47B	10.0	9.2	1.2	10.0	8.3	1.0	7.4	**8.3**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table 8.41 – Measure Rankings and Preference Scores for 2012 Gas Resource Deferral Strategy Portfolios

	Expected Value CO2 Tax													Normalized
Case	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**	**Rank Sum**	**Score**
2B	1.2	1.8	2.3	2.9	4.2	5.4	6.7	7.6	7.8	7.9	8.0	8.3	63.9	6.8
5B	2.2	2.1	2.2	2.3	2.4	2.6	2.8	2.8	2.9	2.8	3.2	3.9	32.2	3.2
5B_CCCT Dry	1.3	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.6	1.7	2.1	2.9	20.1	1.8
5B_CCCT Wet	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	2.3	13.3	1.0
8B	4.5	4.6	4.4	4.4	4.3	4.1	4.0	3.4	2.7	1.7	1.3	2.1	41.7	4.3
9B	3.3	3.4	3.5	3.7	3.8	4.4	4.8	4.6	4.5	4.8	4.7	5.3	50.8	5.3
10B	6.6	6.8	7.1	7.4	7.9	8.4	8.9	8.2	7.4	6.7	6.2	6.2	87.8	9.6
17B	10.0	10.0	10.0	10.0	10.0	10.0	9.3	6.9	5.1	3.1	1.5	1.0	86.9	9.5
18B	8.9	8.9	8.9	8.9	8.9	9.0	8.4	6.2	4.8	3.4	1.9	1.7	79.8	8.7
47B	3.3	3.8	4.5	5.3	6.4	8.0	10.0	10.0	10.0	10.0	10.0	10.0	91.4	10.0

Figure 8.26 - Stochastic Cost versus Upper-tail Risk: $0, $45, and $100 CO$_2$ Tax Levels



WIND RESOURCE ACQUISITION SCHEDULE DEVELOPMENT

Based on the 2012 gas resource deferral modeling results, PacifiCorp chose the “5B_CCCT_Wet” portfolio as the basis for the preferred portfolio. An issue with this portfolio, and wind resource optimization in general, is that the capacity expansion model adds a large amount of wind capacity in certain years and little or none in others. Such a pattern, while optimal from the model's perspective, is not desirable from a business planning perspective.

As noted in Chapter 7, PacifiCorp applied annual wind capacity constraints to reflect realistic system limits. However, additional constraints are required to emulate a long-term procurement program that ideally accounts for rate stability/financial impacts, anticipated demand for construction and equipment resources, flexibility to respond to changing market and regulatory conditions, construction management requirements, and location-specific considerations not factored into the IRP models. The Company believes that given the current sophistication of capacity expansion optimization models, development of a suitable wind acquisition schedule that takes these various factors into account is best handled outside of the model. Consequently, PacifiCorp manually developed a wind acquisition schedule based on the aggregate wind amount from the 5B_CCCT_Wet portfolio, and then ran System Optimizer with this fixed wind schedule and the 5B_CCCT_Wet input assumptions. The resulting portfolio, presented in the next section, constitutes PacifiCorp's preferred portfolio. Table 8.42 shows the wind acquisition schedule and original wind additions from the 5B_CCCT_Wet portfolio.

Table 8.42 – Revised Wind Resource Acquisition Schedule

Wind Resource Acquisition Schedule (Capacity, MW)															
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total (2009-2018)**	**Total (2009-2021)**
East	198	150		100	100	100	150	100	100	50	200	200	150	1,048	1,598
West	45	20	200											265	265
Total	243	170	200	100	100	100	150	100	100	50	200	200	150	1,313	1,863
Wind Additions for Case 5B_CCCT_Wet															
East	99	99					300			750	550			598	1,798
West	45	20												65	65
Total	342	119				140	460	100		750				1,261	1,863

The strategy behind this acquisition schedule is to distribute wind quantities across all years of the business planning period (2009-2018) and through 2021, keeping annual amounts at 200 MW or less. Planning to relatively level annual wind additions provides the following customer and Company benefits:

- Helps to support rate and capital spending stability
- Strikes a balance between the risk of (1) front-loading wind development and then experiencing lower-than-expected CO_2 costs, and (2) deferring wind development and then experiencing higher-than-expected CO_2 costs, termination of the PTC after 2012, or both
- Reduces the risk of RPS compliance penalty costs stemming from procurement delays for projects needed to meet percentage-of-sales requirements in a given year
- Helps in maintaining efficiently sized construction management, engineering, and support teams

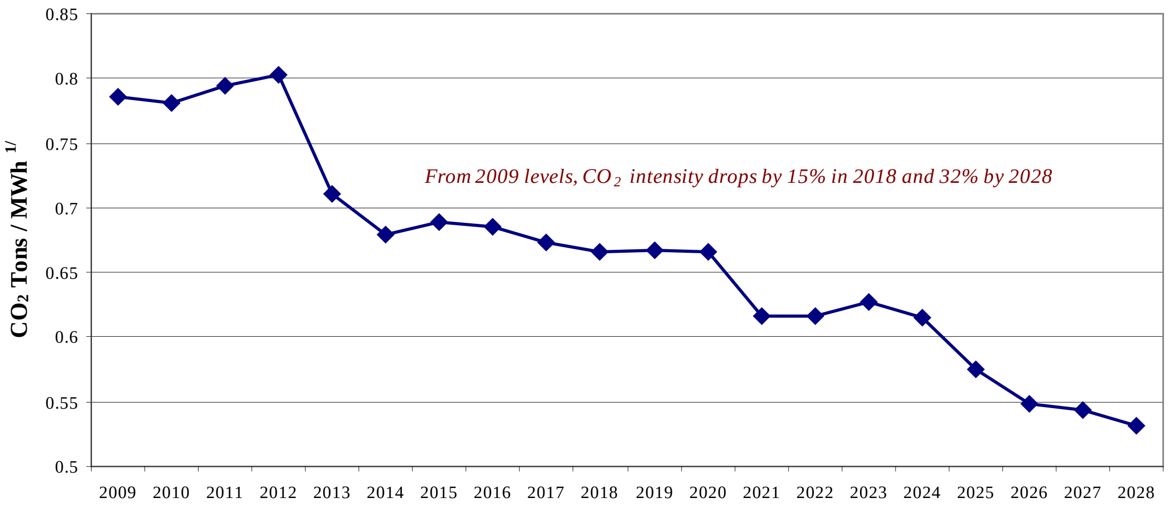
The wind schedule also reflects the addition of 200 MW of west-side wind resources in 2011 to take advantage of regional wind diversity benefits that are not captured in the IRP models.

THE IRP PREFERRED PORTFOLIO

The increasing mix of clean resources reflected in the 2008 IRP preferred portfolio—renewables and demand-side management—reduces the carbon intensity of PacifiCorp's generation fleet (Figure 8.27) and positions the Company well for meeting future climate change and renewable resource requirements. For example, the preferred portfolio exceeds current jurisdictional RPS requirements expressed on a system load basis, and would potentially meet a 15-percent federal RPS requirement such as the one contained in draft legislation proposed by U.S. Representatives Waxman and Markey ("The American Clean Energy and Security Act of 2009"). The addition of energy efficiency resources—reaching 4.2 million kWh by 2018—reduces the system coincident peak load from a 2.7% average annual growth rate (2009-2018) to 1.9%.

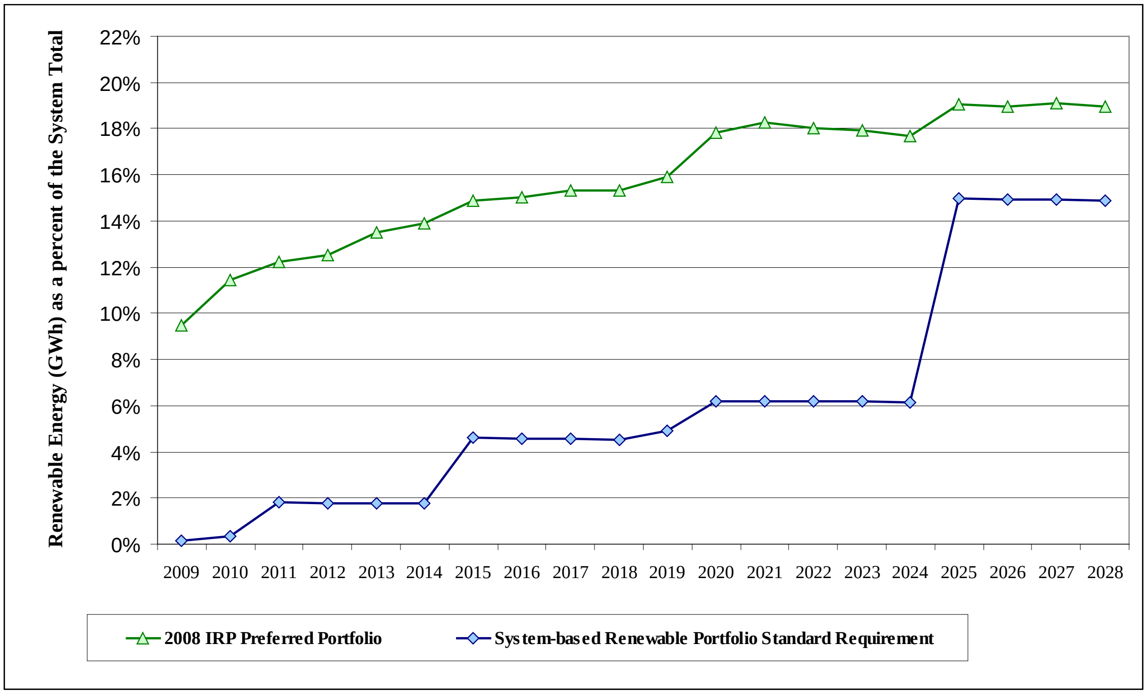
The addition of flexible natural gas resources supports the aggressive expansion of intermittent renewable generation while meeting incremental base load and intermediate load needs. The role of new firm market purchases is to help replace expiring long-term power purchases, and, by adjusting volumes up or down, provide resource flexibility to manage the volatility and uncertainty in load forecasts, commodity prices, and capital costs. The increase in near-term front office transactions takes advantage of the significant price drops in fuels and forward wholesale power in late 2008 and early 2009, providing the opportunity to lower power supply costs before the Company needs to commit to a large new thermal power plant. If construction markets continue to soften as several experts predict, this will create additional cost-saving opportunities through lower plant prices.

Figure 8.27 – Carbon Dioxide Intensity of the 2008 IRP Preferred Portfolio



1/ Generation consists of the output from thermal, renewable and hydro resources based on a \$45/ton CO_2 tax beginning in 2013.

Figure 8.28 – Renewable Portfolio Standard Compliance 2008 IRP Preferred Portfolio



Relative to the preferred portfolio reported in the 2007 IRP Update report (June 2008), the 2008 preferred portfolio relies on significantly less firm market purchases for the period covered in common (2009-2017). For gas resources, the major difference is the addition of a simple-cycle gas plant in 2016; with the acquisition of the Chehalis plant in 2008, there is negligible change in the amount of combined-cycle gas capacity. The 2008 IRP relies more heavily on distributed generation resources, while differences in wind and Class 2 DSM are minimal. Table 8.43 shows the annual resource differences for the two preferred portfolios (2008 IRP less the 2007 IRP Update).

Table 8.43 – Resource Differences, 2008 IRP Preferred Portfolio less 2007 IRP Update Preferred

		Capacity, MW											Total
	Resource	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2008-2017**
East	Gas Combined Cycle (2x1)		-	-	-	(1,096)	-	570	-	-	-	-	(526)
	IC Aero SCCT		-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement		-	-	-	201	-	-	-	-	-	-	201
	Coal Plant Turbine Upgrades		(18)	7	(5)	(12)	2	14	-	8	-	-	(4)
	Geothermal, Blundell 3		-	(35)	-	-	35	-	-	-	-	-	-
	Wind	36 [2/]	(201)	149	(100)	(100)	100	(100)	150	100	100	50	134
	Distributed Generation		6	(13)	6	6	6	6	8	8	8	8	42
	Firm Market Purchases		75	50	150	279	(140)	(546)	(598)	(572)	(66)	800	NA
West	Chehalis CCCT	509 [2/]	-	-	-	-	-	-	-	-	-	-	509
	Coal Plant Turbine Upgrades		-	(8)	(9)	(5)	(5)	-	-	-	-	-	(28)
	Swift Hydro Upgrades*		-	-	-	-	-	-	-	-	-	-	-
	Wind	139 [2/]	45	20	-	-	(100)	-	-	-	-	-	104
	Distributed Generation		2	2	2	2	3	3	3	3	3	3	25
	Firm Market Purchases	(400)	(400)	(657)	(677)	(311)	30	(55)	(100)	(333)	(609)	582	NA
DSM [3/]	Energy Efficiency (Class 2 DSM)	(67)	2	2	(2)	(3)	1	2	3	2	5	87	(55)

[1/] Acquisition of the Chehalis 509 MW combined-cycle plant in Washington.

[2/] For 2008, actual wind additions totaled 545 MW, compared to the planned amount of 370 MW in the 2007 IRP Update

[3/] Expansions of the existing Utah Cool Keeper program and dispatchable irrigation programs are treated as existing resources. Relative to the 2007 IRP Update quantities, the incremental DSM planned expansions reach 525 MW by 2018.

[4/] For the 2007 IRP Update, Class 2 DSM was treated as a decrease to load rather than as a resource included in the preferred portfolio.

Table 8.44 presents the detailed view of the preferred portfolio resources. This portfolio reflects the wind schedule described in the preceding section. Since Class 1 DSM other than the Utah Cool Keeper program was found to be cost-effective in all the portfolios modeled, the preferred portfolio includes up to 120 MW of additional cost-effective Class 1 DSM to be identified through competitive Requests for Proposals and procured in the 2009-2018 time frame. (For the non-CCCT "B series" cases, the capacity expansion model typically selected 91 MW of various Class 1 DSM programs in the east—predominantly irrigation load control and load curtailment—and 34 MW in the west.) This amount is in line with the corporate objective of aggressively pursuing DSM opportunities, and exceeds the 2009 business plan goal by 15 MW. Acquiring the additional Class 1 DSM amounts would reduce the need for front office transactions.

Below are explanatory notes for the portfolio table.

- Swift 1 Upgrades – The three Swift upgrade projects (25 MW each) are shown under the year for which they enter commercial service (2012, 2013, and 2014); however, the planned in-service dates occur after the system peaks for these years. They are available to support the summer peak load in 2013, 2014, and 2015, respectively.
- High Plains and Duke PPA Wind Projects – The High Plains wind project has an October December 2009 in-service date, and is therefore shown under the year for which it enters commercial service (2009); the Duke project has a December 2009 in-service date, but is modeled with a start date of January 1, 2010, and is therefore shown in the year it is available to support the summer peak load (2010).
- Gas resource MW capacities reflect average annual capability rather than the generator nameplate. For the CCCT, the value shown approximates the July maximum capability.
- Class 2 DSM resource capacities reflect summer peak values.
- The capacities shown for the coal plant CCS (carbon capture and sequestration) retrofit resources represent replacement capacities for the existing units. The replacement capaci-

ty is smaller than the original unit size, which is due to a capacity penalty for capturing the CO_2.

- Front office transactions and growth resources reflect amounts acquired for the given year only, and are not cumulative.
- For the 20-year totals column, growth resources are reported as an eight-year average from 2021-2028.
- Short-term resource totals comprise the sum of front office transactions and growth resources.

Table 8.45 shows the resulting capacity load and resource balance for 2009-2018 with preferred portfolio resources included. Wind and 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 Table 8.44. Figures 8.29 and 8.30 consist of pie charts showing the energy and capacity mixes of the portfolio for 2009, 2014, and 2018. (Note that for the capacity charts, the expected system peak capacity contribution for wind resources is shown.)

Table 8.44 – Preferred Portfolio, Detail Level

		Capacity, MW																				Resource Total	
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**10 Year**	**20 Year**
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	CCCT F 2x1	-	-	-	-	-	570	-	-	-	-	-	-	-	-	-	-	-	-	-	-	570	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell Geothermal 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, High Plains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35% Capacity Factor	-	150	-	100	100	100	150	100	100	50	200	200	150	-	-	-	-	-	-	-	850	1,400
	Total Wind	**99**	**249**	**-**	**100**	**100**	**100**	**150**	**100**	**100**	**50**	**200**	**200**	**150**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,048**	**1,598**
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, Utah-Cool Keeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	-	-	-	-	-	-	-	-	-	-	Up to 90	Up to 90
	DSM, Class 2, Goshen	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, Utah	40	46	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	447	971
	DSM, Class 2, Wyoming	-	3	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	68	164
	DSM, Class 2 Total	**42**	**51**	**49**	**52**	**55**	**55**	**56**	**56**	**58**	**59**	**58**	**59**	**60**	**62**	**64**	**64**	**71**	**67**	**69**	**67**	**532**	**1,173**
	FOT Utah, 3rd Qtr HLH	-	-	-	44	50	-	2	28	-	-	-	7	50	50	50	50	-	-	50	-		
	FOT Mead, 3rd Qtr HLH	-	-	-	-	-	-	-	-	517	600	600	600	600	600	600	600	600	600	600	600		
	FOT Mona/Nevada Utah Border, 3rd Qtr HLH	75	50	150	350	443	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-		
	FOT East Total	**75**	**50**	**150**	**394**	**493**	**200**	**202**	**228**	**717**	**800**	**800**	**807**	**650**	**650**	**650**	**650**	**600**	**600**	**650**	**600**		
	Growth Resource - Goshen	-	-	-	-	-	-	-	-	-	-	-	-	204	187	198	219	-	-	192	-		
	Growth Resource - Utah North	-	-	-	-	-	-	-	-	-	-	-	-	212	308	238	242	-	-	-	-		
	Growth Resource - Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	73	79	126	167	-	-	196	-		
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, Yakima, 29% Capacity Factor PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Walla Walla, 29% Capacity Factor PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	**45**	**20**	**200**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**265**	**265**
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	25	-	-	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	-	-	-	-	-	-	-	-	-	-	Up to 30	Up to 30
	DSM, Class 2, Washington	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, West Main	28	28	30	30	30	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, Yakima	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	**35**	**36**	**39**	**39**	**38**	**39**	**39**	**39**	**39**	**29**	**29**	**29**	**30**	**29**	**29**	**30**	**29**	**30**	**30**	**30**	**372**	**665**
	FOT COB, Flat Annual	-	-	59	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-		
	FOT COB, 3rd Qtr HLH	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338		
	FOT Mid-Columbia, Flat Annual	-	-	-	-	-	-	-	-	-	171	228	228	37	67	71	63	68	87	109	165		
	FOT Mid-Columbia, 3rd Qtr HLH	-	-	-	400	400	300	400	400	-	121	105	160	-	-	-	7	308	313	291	235		
	FOT West Main, 3rd Qtr HLH	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50		
	FOT West Total	**-**	**-**	**59**	**839**	**839**	**739**	**739**	**689**	**289**	**582**	**721**	**776**	**424**	**454**	**459**	**457**	**764**	**788**	**788**	**788**		
	Growth Resource - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	106	97	134	135	127	128	396	403		
	Growth Resource - West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	660	67	666		
	Growth Resource - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	157	163	268	271	215	294	315	317		
	Annual Additions, Long Term Resources	**257**	**467**	**378**	**491**	**286**	**823**	**266**	**485**	**218**	**158**	**289**	**291**	**243**	**94**	**94**	**95**	**471**	**97**	**123**	**97**		
	Annual Additions, Short Term Resources	**75**	**50**	**209**	**1,234**	**1,332**	**939**	**942**	**918**	**1,006**	**1,382**	**1,521**	**1,583**	**1,825**	**1,937**	**2,074**	**2,141**	**2,313**	**2,470**	**2,603**	**2,773**		
	Total Annual Additions	**332**	**517**	**587**	**1,725**	**1,618**	**1,762**	**1,208**	**1,402**	**1,224**	**1,540**	**1,811**	**1,873**	**2,068**	**2,031**	**2,168**	**2,236**	**2,785**	**2,567**	**2,727**	**2,870**		

* Up to 120 MW of additional cost-effective Class 1 DSM programs (90 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced accordingly

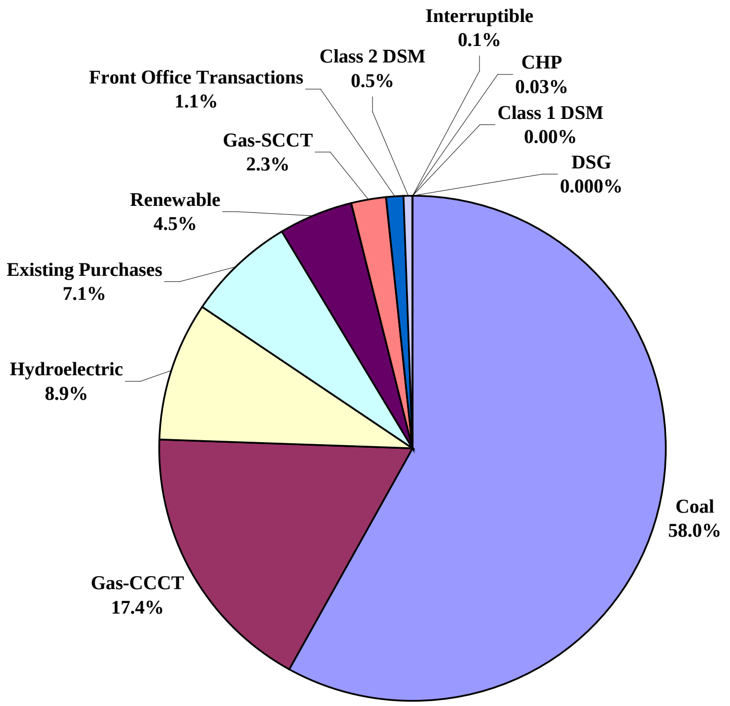
.

Table 8.45 - Preferred Portfolio Load and Resource Balance (2009-2018)

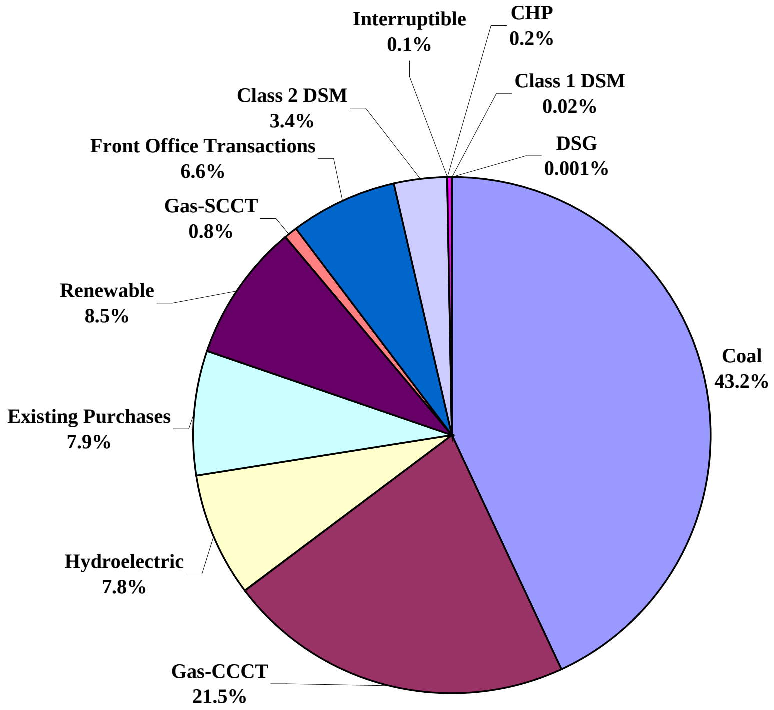
Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East										
Thermal	5,983	5,998	6,025	6,066	6,066	6,078	6,079	6,087	6,088	5,863
Hydroelectric Generation	135	135	135	135	135	135	135	135	135	135
Demand-side Management	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
Qualifying Facilities	151	151	151	151	151	151	151	151	151	151
Interruptible Contracts	237	237	237	237	237	237	237	237	237	237
Transfers	854	914	794	685	737	565	769	737	231	519
East Existing Resources	**8,614**	**8,534**	**8,476**	**8,238**	**8,300**	**8,149**	**8,361**	**8,326**	**7,831**	**7,905**
Combined Heat and Power	2	4	6	9	11	14	18	22	26	30
Distributed Standby Generation	4	8	12	15	19	23	27	31	35	38
DSM, Class 2	36	79	119	160	205	249	294	338	384	431
Front Office Transactions	75	50	150	394	493	200	202	228	717	800
Gas	0	0	0	201	201	771	771	1,032	1,032	1,032
Geothermal	0	0	0	0	35	35	35	35	35	35
Wind	9	12	12	15	17	20	23	26	28	29
Growth Resource	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**126**	**153**	**299**	**794**	**980**	**1,310**	**1,369**	**1,711**	**2,255**	**2,395**
East Total Resources	**8,740**	**8,687**	**8,774**	**9,032**	**9,280**	**9,460**	**9,730**	**10,037**	**10,086**	**10,300**
Load (Coincident Peak)	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	**7,538**	**7,717**	**7,908**	**8,151**	**8,388**	**8,524**	**8,774**	**9,048**	**9,150**	**9,355**
Planning reserves (12%)	731	769	771	786	797	841	865	890	837	845
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	**802**	**840**	**841**	**857**	**867**	**912**	**935**	**961**	**908**	**915**
East Obligation + Reserves	**8,339**	**8,556**	**8,749**	**9,007**	**9,255**	**9,436**	**9,709**	**10,009**	**10,058**	**10,271**
East Position	**401**	**131**	**25**	**25**	**25**	**24**	**21**	**28**	**29**	**29**
East Reserve Margin	**17.3%**	**13.7%**	**12.3%**	**12.3%**	**12.3%**	**12.3%**	**12.2%**	**12.3%**	**12.3%**	**12.3%**
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydroelectric Generation	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
Demand-side Management	0	0	0	0	0	0	0	0	0	0
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
Qualifying Facilities	120	120	120	120	120	120	120	120	120	120
Transfers	(855)	(914)	(795)	(686)	(738)	(565)	(769)	(737)	(231)	(520)
West Existing Resources	**4,530**	**4,281**	**3,958**	**3,198**	**3,217**	**3,392**	**3,300**	**3,325**	**3,815**	**3,551**
Combined Heat and Power	1	2	4	5	7	9	10	12	14	16
Distributed Standby Generation	1	2	4	5	6	7	8	9	11	12
DSM, Class 1	0	0	0	0	0	0	0	0	0	0
DSM, Class 2	26	54	83	112	140	169	199	228	257	279
Front Office Transactions	0	0	59	839	839	739	739	689	289	582
Other	0	0	0	0	0	0	0	0	0	0
Wind	0	0	8	8	8	8	8	8	8	8
Growth Resource	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**29**	**58**	**157**	**969**	**1,000**	**933**	**965**	**947**	**580**	**896**
West Total Resources	**4,559**	**4,340**	**4,115**	**4,167**	**4,217**	**4,325**	**4,265**	**4,272**	**4,395**	**4,448**
Load (Coincident Peak)	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	**3,892**	**3,912**	**3,780**	**3,845**	**3,896**	**3,980**	**3,927**	**3,932**	**4,001**	**4,086**
Planning reserves (12%)	307	319	346	334	333	355	345	348	401	370
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	**313**	**325**	**353**	**340**	**339**	**362**	**352**	**355**	**408**	**377**
West Obligation + Reserves	**4,199**	**4,230**	**4,126**	**4,179**	**4,229**	**4,335**	**4,272**	**4,280**	**4,402**	**4,456**
West Position	**360**	**110**	**(11)**	**(12)**	**(12)**	**(10)**	**(7)**	**(8)**	**(7)**	**(9)**
West Reserve Margin	**21.1%**	**14.6%**	**11.5%**	**11.5%**	**11.5%**	**11.6%**	**11.7%**	**11.6%**	**11.7%**	**11.6%**
System										
Total Resources	**13,299**	**13,027**	**12,889**	**13,199**	**13,497**	**13,785**	**13,995**	**14,309**	**14,481**	**14,747**
Obligation	**11,430**	**11,628**	**11,687**	**11,996**	**12,284**	**12,504**	**12,701**	**12,980**	**13,151**	**13,441**
Reserves	**1,115**	**1,165**	**1,194**	**1,197**	**1,206**	**1,274**	**1,287**	**1,316**	**1,315**	**1,292**
Obligation + Reserves	**12,544**	**12,793**	**12,882**	**13,192**	**13,490**	**13,777**	**13,988**	**14,296**	**14,466**	**14,733**
System Position	**754**	**234**	**7**	**7**	**6**	**7**	**8**	**13**	**15**	**14**

Figure 8.29 – Current and Projected PacifiCorp Resource Energy Mix

2009 Resource Energy Mix with Preferred Portfolio Resources
($45 CO2 Tax)



2014 Resource Energy Mix with Preferred Portfolio Resources
($45 CO2 Tax)



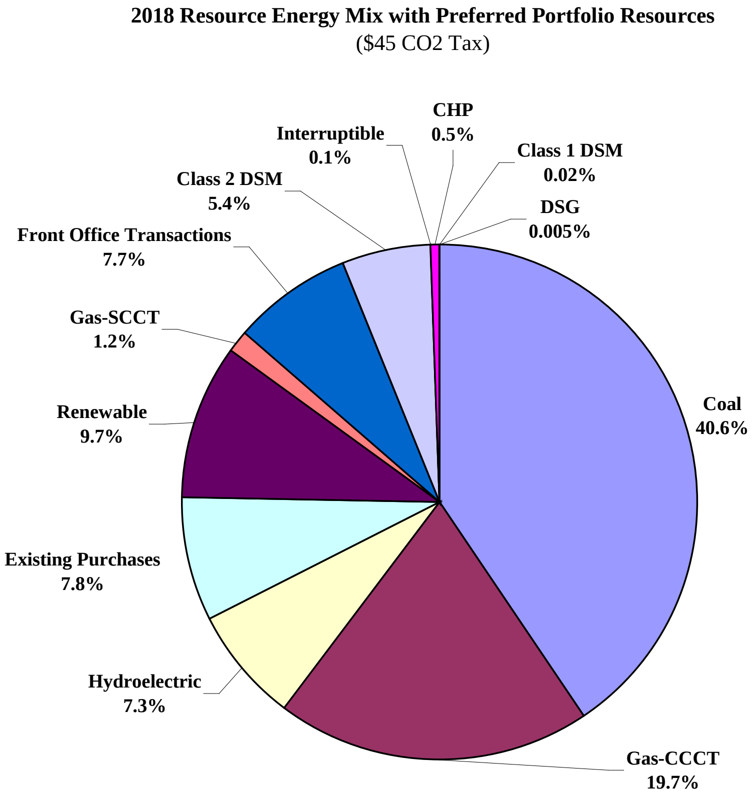
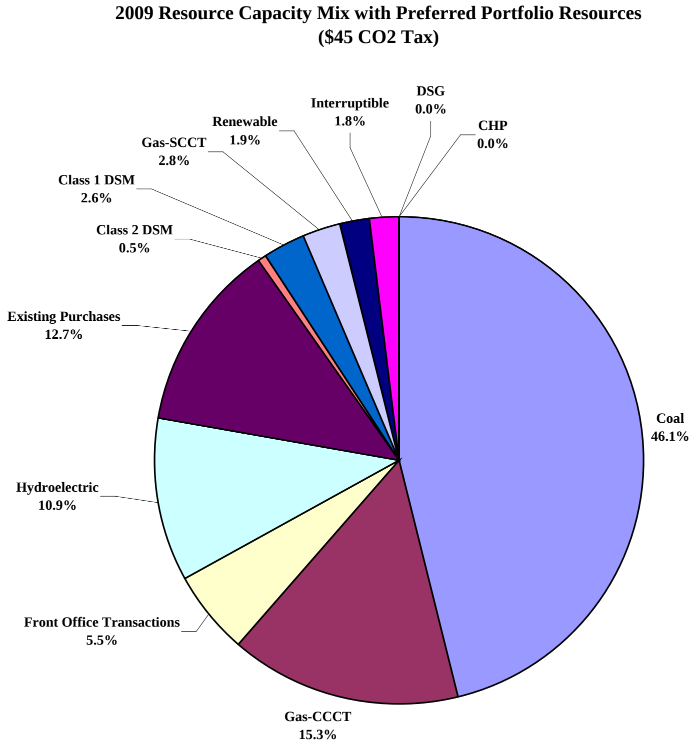
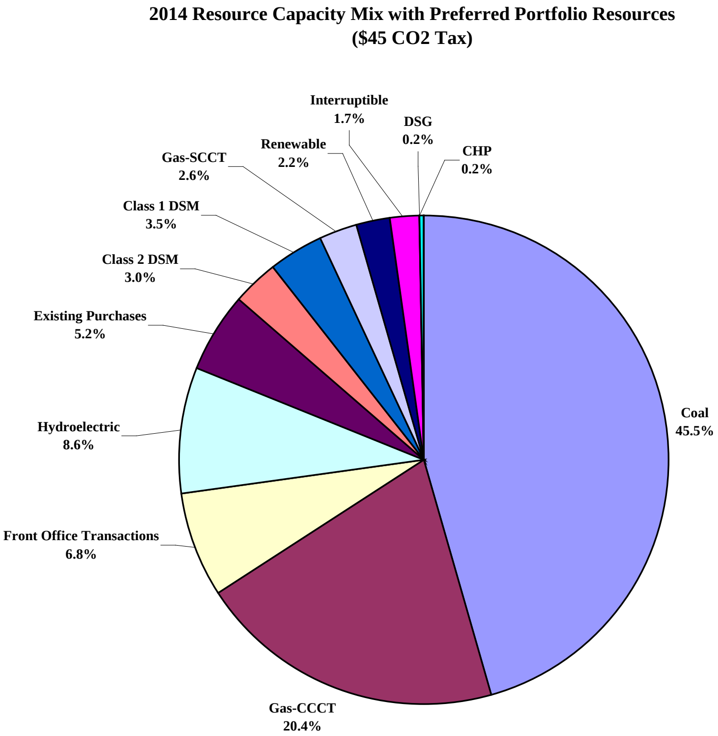
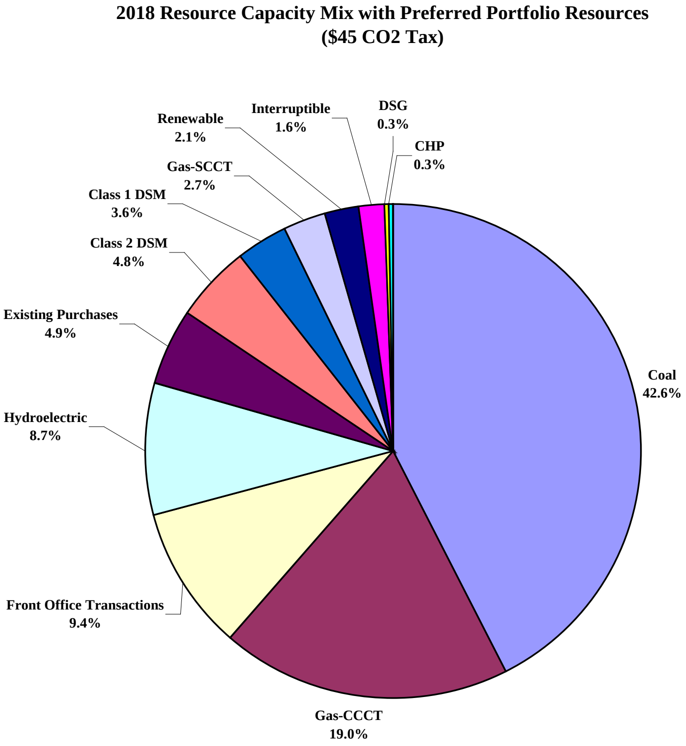


Figure 8.30 – Current and Projected PacifiCorp Resource Capacity Mix




2014 Resource Capacity Mix with Preferred Portfolio Resources
($45 CO2 Tax)
Interruptible 1.7%
DSG 0.2%
CHP 0.2%
Renewable 2.2%
Gas-SCCT 2.6%
Class 1 DSM 3.5%
Class 2 DSM 3.0%
Existing Purchases 5.2%
Hydroelectric 8.6%
Front Office Transactions 6.8%
Gas-CCCT 20.4%
Coal 45.5%


2018 Resource Capacity Mix with Preferred Portfolio Resources
($45 CO2 Tax)
Renewable 2.1%
Interruptible 1.6%
DSG 0.3%
CHP 0.3%
Gas-SCCT 2.7%
Class 1 DSM 3.6%
Class 2 DSM 4.8%
Existing Purchases 4.9%
Hydroelectric 8.7%
Front Office Transactions 9.4%
Gas-CCCT 19.0%
Coal 42.6%

PORTFOLIO IMPACT OF PACIFICORP'S FEBRUARY 2009 LOAD FORECAST

PacifiCorp prepared a new load forecast in February 2009 after reviewing actual loads through January 2009. This forecast is being used to support corporate planning efforts including the acquisition path analysis outlined in the next Chapter, as well as recent regulatory filings.

Table 8.46 compares the coincident peak loads for the two load forecasts. For the 2009 business plan, the load forecast was adjusted to include the expected impact of historical Class 2 DSM programs, which are assumed to contribute incremental load reductions in the future as equipment and appliances are replaced with higher-efficiency alternatives. This load forecast adjustment was not included in previous IRP modeling, but is factored into the portfolio modeling using the February 2009 load forecast. As with the federal lighting standards adjustment described in Chapter 5, this DSM adjustment has the effect of increasing the load forecast for capacity expansion modeling only, so that the model can select additional DSM to fill the load gap. Including this adjustment also ensures that sufficient resource capacity is added in case the full amount of estimated future load reductions from existing Class 2 DSM programs is not realized. This adjustment, which partially offsets the recession-related load reductions, ranges from 34 MW in 2009 to 337 MW by 2018. Appendix E reports the detailed February 2009 forecast net of expected future load reductions attributable to existing Class 2 DSM programs and federal lighting standards.

Table 8.46 – Coincident Peak Load Forecast Comparison

Nov. 2008 Forecast	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
West	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
System	**10,150**	**10,371**	**10,640**	**10,991**	**11,281**	**11,501**	**11,798**	**12,127**	**12,384**	**12,674**
Feb. 2009 Forecast	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	6,722	6,924	7,220	7,483	7,741	7,905	8,173	8,410	8,664	8,886
West	3,265	3,324	3,379	3,447	3,491	3,554	3,608	3,624	3,719	3,793
System	**9,987**	**10,248**	**10,599**	**10,930**	**11,232**	**11,459**	**11,781**	**12,034**	**12,383**	**12,679**
Difference	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	(35)	(25)	70	79	98	126	144	107	173	190
West	(128)	(98)	(111)	(140)	(147)	(168)	(161)	(200)	(174)	(185)
System	**(163)**	**(123)**	**(41)**	**(61)**	**(49)**	**(42)**	**(17)**	**(93)**	**(1)**	**5**

Although the Company could not accommodate a comprehensive portfolio evaluation based on the February 2009 load forecast without contravening certain state IRP filing requirements, PacifiCorp was nevertheless able to conduct a preferred portfolio sensitivity analysis with it.

PacifiCorp developed a portfolio using this new DSM-adjusted load forecast and the case 5 input assumptions ($45/ton CO_2 tax and low June 2008 forward price curves) with the CCCT fixed in 2014. As indicated in table 8.45, the peak load reductions are not sufficient to eliminate or defer a gas combined-cycle plant.

The resource impacts of applying the new load forecast with the DSM adjustment described above, relative to the 5B_CCCT_Wet portfolio, are as follows:

- The IC aero SCCT originally added in 2016 is no longer needed
- Front office transactions are deferred in both the east and west, and decrease overall by about 100 MW by 2020; the east experiences a net increase of about 90 MW while the west experiences a net decrease of 185 MW in line with the lower loads
- To make up for the loss of the IC aero SCCT and front office transactions, the model added 41 MW of customer standby generation (30 MW in the east; 12 MW in the west), 50 MW of utility-scale biomass capacity in 2015-2016, and moved up 243 MW of wind from 2019 to 2017

Table 8.47 shows the resource capacity differences through 2020 between the portfolio produced using the new load forecast and the wet-cooled CCCT portfolio (5B_CCCT_Wet).

Table 8.47 – Resource Capacity Differences, February 2009 Load Forecast Portfolio less Wet-Cooled CCCT Portfolio

		Capacity, MW											
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East													
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-
	IC Aero	-	-	-	-	-	-	-	(261)	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	243	-	(243)	-
	CHP - Reciprocating Engine	-	-	1	-	-	-	-	-	-	-	-	-
	Distributed Standby Generation	4	4	4	4	4	4	4	4	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	(2.1)	-	-	-	-	-	-	-
	DSM, Class 2 Total	0.3	-	-	1.9	0.6	0.8	0.4	-	-	-	-	-
	FOT Utah, 3rd Qtr HLH	-	-	-	(30)	-	-	(17)	5	-	50	47	50
	FOT Mead, 3rd Qtr HLH	-	-	-	-	-	-	-	-	64	-	-	-
	FOT Mona/Nevada Utah Border, 3rd Qtr HLH	-	-	-	(7)	(74)	-	-	-	-	-	-	-
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-
West													
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	1	-	-	-	-	-	-	-	-
	Distributed Standby Generation	2	2	2	2	2	2	2	2	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	1.9	-	-	-	-
	DSM, Class 2 Total	-	-	-	-	1.1	0.5	-	-	-	-	-	-
	FOT Mid-Columbia, Flat Annual	-	-	(55)	-	-	-	-	-	-	-	-	-
	FOT Mid-Columbia, 3rd Qtr HLH	-	-	-	-	-	-	-	-	26	(17)	(22)	(19)
	FOT West Main, 3rd Qtr HLH	-	-	-	(44)	-	(71)	(58)	-	-	64	54	(42)
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-

Since the relative resource impact of the DSM-adjusted February 2009 load forecast is minimal until 2016, PacifiCorp decided to retain the IC aero SCCT in the preferred portfolio. Also supporting this decision is the uncertainty over the timing and pace of an economy recovery, combined with the short lead-time for a gas peaking resource and the potential need for such resources to support wind integration. Consideration of the timing and type of gas resources and other resource changes will be handled as part of a comprehensive assumptions update and portfolio analysis to be conducted for the next business plan and 2008 IRP update.

9. ACTION PLAN AND RESOURCE RISK MANAGEMENT

INTRODUCTION

PacifiCorp's 2008 IRP action plan identifies the steps the Company will take during the next two to four years to implement the plan, covering the 10-year resource acquisition time frame, 2009-2018. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions expected during the action plan time horizon and other events that could materially impact resource acquisition strategies.

The resources included in the 2008 IRP preferred portfolio were used to help define the actions included in the action plan, focusing on the size, timing, and type of resources needed to meet load obligations and current and potential future state regulatory requirements. The preferred portfolio resource combination was determined to be the lowest cost on a risk-adjusted basis accounting for cost, risk, reliability, and regulatory uncertainty.

The 2008 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study completion The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties. The current volatile economic and regulatory environment will likely require near-term alteration to resource plans as a response to specific events and improved clarity concerning the direction of the economy and government energy and environmental policies. For example, the economic stimulus package enacted in February 2009 ("The American Recovery and Reinvestment Act of 2009") introduced a number of provisions affecting resource planning, including extension and expansion of renewable and distributed energy technology tax benefits, funding of grid infrastructure improvements, and block grants for energy efficiency improvements. Provisions of the economic stimulus package, other than the renewable PTC extension, require more analysis to determine how they impact the Company and should be addressed within the IRP analytical framework. On the climate change mitigation front, the Waxman-Markey CO_2 cap-and-trade provisions are under investigation, but the Company is not able to determine the impact on resource plans until the legislation is finalized. Complicating the picture are state environmental/energy legislative proposals, such as Oregon's Senate Bill 80, that establish a state CO_2 cap-and-trade system.

Resource information used in the 2008 IRP, such as capital and operating costs, is consistent with that used to develop the Company's business plan completed in December 2008. However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost, and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

In addition to the action plan and acquisition path analysis, this chapter addresses a number of topics associated with resource risk management. These topics include the following:

- Managing carbon risk for existing plants

- The use of physical and financial hedging for electricity price risk
- Managing gas supply risk
- The treatment of customer and investor risks for resource planning

THE INTEGRATED RESOURCE PLAN ACTION PLAN

Table 9.1 is a summary of the annual MW capacity and timing for the resources contained in the 2008 IRP preferred portfolio. A more comprehensive summary of portfolio resources can be found in Chapter 8.

Table 9.1 – Preferred Portfolio, Summary Level

		Capacity, MW										Cumulative Total
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	
East												
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-	200
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	128
	Geothermal	-	-	-	-	35	-	-	-	-	-	35
	Wind	99	249	-	100	100	100	150	100	100	50	1,048
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4	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	532
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800	
West												
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	42
	Swift Hydro Upgrades [2/]	-	-	-	25	25	25	-	-	-	-	75
	Wind	45	20	200	-	-	-	-	-	-	-	265
	CHP	1	1	1	1	2	2	2	2	2	2	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	372
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582	

[1/] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.

[2/] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

The 2008 IRP action plan, detailed in Table 9.2, provides the Company with a road map for moving forward with new resource acquisitions, including major transmission projects needed to support the preferred portfolio and other Company objectives. (More detail on transmission expansion action items is provided in Chapter 10.)

Table 9.2 – 2008 IRP Action Plan

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**	**2009 - 2018**	Acquire an incremental 1,400 MW of renewables by 2018, in addition to the already planned 75 MW of major hydroelectric upgrades in 2012-2014; PacifiCorp's projected renewable resource inventory by 2018 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 269 MW of wind resources in 2010 that are currently in the project pipeline, 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 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 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 solar and emerging technologies, government financial incentives, and procure 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 at the state and federal levels, and adjust the renewable acquisition timeline accordingly*
2	**Firm Market Purchases**	**2009 - 2013**	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until no sooner than the beginning of summer 2014 • Acquire the following resources: – Up to 1,400 MW of economic front office transactions on an annual basis as needed through 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) • Resources will be procured through multiple means: (1) reactivation of the suspended 2008 All-Source

Action Item	Category	Timing	Action(s)
			RFP in late 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 2009 load forecast • *Acquire incremental transmission through Transmission Service Requests to support resource acquisition*
3	**Peaking / Intermediate / Base-load Supply-side Resources**	**2012 - 2016**	Procure long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame • 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 in late 2009 – The Company plans to submit Company resources (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.*
4	**Plant Efficiency Improvements**	**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 2016, which are expected to add 128 MW of incremental in the east and 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*[55] • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules*
5	**Class 1 DSM**	**2009-2018**	Acquire at least 200 - 300 MW of cost-effective Class 1 demand-side management programs for implementation in the 2009-2018 time frame • *Pursue up to 200 MW of expanded Utah Cool Keeper program participation by 2018* • *Pursue up to 130 MW of additional cost-effective class 1 DSM products(90 MW in the east side and 30*

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

Action Item	Category	Timing	Action(s)
			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, 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.
6	**Class 2 DSM**	**2009-2018**	Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa • *Procure through the currently active DSM RFP and subsequent DSM RFPs*
7	**Class 3 DSM**	**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*
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 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
9	**Planning Process**	**2009-2010**	Portfolio modeling improvements • Complete the implementation of System Optimizer capacity expansion model enhancements for

Action Item	Category	Timing	Action(s)
	Improvements		improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level • 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 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 • Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for 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
10	**Transmission**	**2009-2011**	Obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona To 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
11	**Transmission**	**2010**	Permit and build Utah/Idaho/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Permit and construct a 345 kV line between Populus to Terminal
12	**Transmission**	**2012**	*Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Mona and Oquirrh*

Action Item	Category	Timing	Action(s)
13	**Transmission**	**2014**	*Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct 230 kV and 500 kV line between Windstar and Populus* • *Permit and construct a 345 kV line between Sigurd and Red Butte*
14	**Transmission**	**2016**	*Permit and build Northwest/Utah/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Populus and Hemingway*
15	**Transmission**	**2017**	*Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Aeolus and Mona*

PROGRESS ON PREVIOUS ACTION PLAN ITEMS

This section describes progress that has been made on previous active action plan items documented in the 2007 Integrated Resource Plan Update report filed with the state commissions on June 11, 2008. Most of these action items have been superseded in some form by items identified in the current IRP action plan.

Action Item 1: Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources.

Status: PacifiCorp is on pace to exceed the 2,000 MW target by 2013. Since 2005, the Company's projected renewable resource inventory has grown by 1,405 MW, accounting for existing resources and those under construction, contract, or included in a capital budget. The incremental renewables identified in the 2008 IRP preferred portfolio and action plan bring the target to about 2,040 MW by 2013. The projected inventory exceeds 2,540 MW by 2018.

Action Item 2: Acquire the base Class 2 DSM (Pacific Power and Energy Trust of Oregon combined, including energy savings in Oregon beyond that funded by the ETO) of 300 MWa and 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Public Utility Commission of Oregon. PacifiCorp will reassess Class 2 objectives upon completion of system-wide DSM potential study. Will incorporate potentials study findings into the 2007 IRP update and 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.

> *Status: This action item has been superseded by Action Item no. 6 in Table 9.2. PacifiCorp issued a DSM RFP in November 2008 to help meet Class 1 DSM acquisition goals.*

Action Item 3: Targets were established through potential study work performed for the 2007 IRP. Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified. A new potential study was completed June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

> *Status: This action item has been superseded by Action Item no. 5 in Table 9.2. PacifiCorp developed Class 1 DSM supply curves using the DSM potentials study data, and incorporated them into the portfolio modeling for this IRP.*

Action Item 4: Although not currently in the base resource stack, the Company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. PacifiCorp will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes.

> *Status: This action item has been superseded by Action Item no. 7 in Table 9.2. PacifiCorp developed Class 3 DSM supply curves using the DSM potentials study data, and incorporated them into the portfolio modeling for this IRP. The all-source DSM RFP seeks price-responsive product proposals.*

Action Item 5: Pursue at least 75 MW of combined heat and power generation for the west-side and 25 MW for the east-side, to include purchase of combined heat and power output pursuant to PURPA regulations and from supply-side RFPs. The potential study results will be incorporated into the 2007 update and 2008 integrated resource planning processes.

> *Status: This action item has been superseded by Action Item no. 8 in Table 9.2. PacifiCorp has about 75 MW online of CHP/other distributed generation resources and 30-40 MW in the project pipeline.*

Action Item 6: [Distributed Generation] Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes.

> *Status: This action item has been successfully completed. Chapter 6 describes how PacifiCorp incorporated distributed generation resources in the 2008 IRP portfolio modeling process.*

Action Item 7: Procure base load / intermediate load / summer peak resources system-wide by the summer of 2012 through 2016. This is part of the requirement included in the 2012 Base Load RFP and the 2008 All Source RFP.

> *Status: This action item has been superseded by Action Item no. 3 in Table 9.2. PacifiCorp will reactivate the suspended 2008 All-Source RFP in late 2009 to assist in procuring the needed resources*

Action Items 8 through 12:

> *Status: These action items are no longer active.*

Action Item 13: Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability. Work with other transmission providers to facilitate joint projects where appropriate.

> *Status: This action item has been superseded by Action Item nos. 10 through 15 in Table 9.2. Chapter 4 and Chapter 10 outline the Company's transmission expansion plans.*

Action Item 14: Continue to have dialogue with stakeholders on Global Climate Change issues.

> *Status: PacifiCorp continues to participate in numerous forums that address these issues. PacifiCorp's Environmental Policy and Strategy department and Government Affairs de-*

> *partment are among the lead organizations within the Company that participate in ongoing policy dialogues.*

Action Item 15: Evaluate technologies that can reduce the carbon dioxide emissions of the Company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power. For the 2008 IRP, include integrated gasification combined cycle (IGCC) plants with carbon capture and sequestration as a resource option for selection.

> *Status: A variety of clean generating technologies were evaluated in this IRP, including a range of renewables, nuclear plants, and coal plants with carbon capture and sequestration (IGCC and conventional coal plant CCS retrofits).*

Action Item 16: Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system.

> *Status: This action item has been superseded by Action Item Nos. 1 and 9 in Table 9.2. PacifiCorp is currently updating its wind integration cost estimates, and will include the results as Appendix F in the separate appendix volume for the May 29 IRP filing. PacifiCorp is also pursuing operational improvements for integrating wind resources. This activity is briefly described in the Resource Procurement Strategy section below.*

Action Item 17: Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. PacifiCorp has successfully updated modeling assumptions, including detailed representation of state RPS requirements as system load-based constraints. See Chapter 7 for details on the modeling approach for representing RPS compliance and CO_2 costs.*

Action Item 18: Work with states to gain acknowledgement or acceptance of the 2008 integrated resource plan and action plan. To the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs.

> *Status: Activity under this action item will commence after filing of the 2008 IRP with the state commissions.*

Action Item 19: In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. In formulating market purchase options for the IRP models, the Company lacked information with which to discriminate such purchases from the proxy front office transaction (FOT) resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the 2008 All-Source RFP to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received*

> *no intermediate-term market purchase bids; therefore, such resources could not be reasonably modeled for this IRP. (See Chapter 6, "Resource Options") PacifiCorp will continue to investigate the formulation of satisfactory intermediate-term market purchases for portfolio modeling contingent on acquiring suitable market data.*

Action Item 20: For the 2008 IRP, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.

> *Status: This action item was successfully completed. PacifiCorp designed a portfolio analysis to address this requirement, estimating a system-wide hard cap based on Oregon's HB 3543 emission reduction goals. A description of this portfolio scenario ("case 40") is provided in Chapter 7; modeling results are provided in Chapter 8.*

Action Item 21: For the 2008 IRP, further develop with stakeholders, use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. The Company will investigate functionality in the System Optimizer model that allows the application of an LOLP constraint for capacity planning.*

Action Item 22: For the 2008 IRP, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.

> *Status: This action item has been successfully completed. PacifiCorp incorporated existing plant retrofits with carbon capture and sequestration technology as capacity expansion model resource options. Additionally, portfolios were developed to simulate the effect of forced coal plant back-down through high CO_2 costs and emissions hard cap constraints. The associated analysis is provided in Chapter 8.*

Action Item 23: Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emission rates to short-term market transactions.

> *Status: This action item has been superseded by Action Item no. 9 Table 9.2, which highlights the CO_2 modeling enhancements that PacifiCorp is currently in the process of implementation with its model software vendor, Ventyx Energy, LLC. Completion of the software enhancements are expected in the summer of 2009.*

IRP ACTION PLAN LINKAGE TO BUSINESS PLANNING

The IRP is not only a regulatory requirement, but is also a primary tool for PacifiCorp's business planning. As indicated in Chapter 2, the Company has made a concerted effort to further align these two planning processes during this IRP cycle. The business planning process addresses the impacts of resources on the Company's financial health, electricity rates, and the prospects for successful recovery of shareholder investments. Considerations such as resource affordability and financeability thus serve as checks to make sure that the IRP's long-term planning perspective comports with prudent utility business practices under today's commercial and regulatory environments.

For IRP and business planning alignment purposes, major resource differences between the 2008 preferred portfolio and the 2009 business plan approved in December 2008 were analyzed by PacifiCorp Energy's finance department for rate and financial impacts. This analysis also supported credit rating agency review of the business plan. The major resource changes included deferral of the CCCT to 2014 from 2012, deferral of the IC Aero SCCT to 2016 from 2013, and a modified wind acquisition schedule. (The preferred portfolio includes an additional 450 MW from 2009 through 2018.)

RESOURCE PROCUREMENT STRATEGY

To acquire resources outlined in the 2008 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, the Company will use its IRP models to support resource evaluation as part of the procurement process, with updated assumptions including load forecasts, commodity prices, and regulatory requirement information available at time that the resource evaluations occur. This will ensure that the resource evaluations account for a long-term system benefit view in alignment with the IRP portfolio analysis framework as directed by state procurement regulations, and with business planning goals in mind.

The sections below profile the general procurement approaches for the key resource categories covered in the action plan: renewables, demand-side management, thermal plants, distributed generation, and market purchases.

Renewable Resources

The renewables 2008R-1 shelf RFP is representative of the mechanism under which the Company will issue subsequent RFPs to meet most of the renewable resource acquisition goals over the ten-year business planning horizon. The 2008R-1 shelf RFP, to be re-issued on a periodic basis, will allow the Company to react effectively to power supply market developments and changes in the status of RPS requirements, the production tax credit, other financial incentives, and CO_2 legislation. The Company will seek both cost-effective conventional and emerging renewable technologies through the RFP process, including those coupled with energy storage. Qualifying Facilities under the Public Utilities Regulatory Policy Act (PURPA), at least 10 MW in size, are also treated as eligible resources under this particular RFP program.

The Company will also pursue renewable resources through means other than the shelf RFP in recognition that strong competition for renewable projects, and the dynamic nature of renewable construction and equipment markets, will require the Company to respond quickly and efficiently as resource opportunities arise. Other procurement strategies that PacifiCorp will pursue in parallel include bilateral negotiations, PURPA contracting, and self-development.

In addition to supply-side resource acquisition, the Company will add transmission infrastructure and flexible generating resources to support and integrate wind generation. PacifiCorp will also work to improve its understanding of how to integrate large amounts of wind into its portfolio in a reliable and cost-effective manner. Areas of focus include wind forecasting, scheduling practices, curtailment tools, and regional coordination activities.

Demand-side Management

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results (such as the Cool Keeper program). In other cases, PacifiCorp manages the program and contracts out specific tasks (such as the Energy FinAnswer program). A third method is to operate the program completely in-house as was done with the Idaho Irrigation Load Control program. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness. With some RFP's, PacifiCorp developed a specific program design, and put that design out to competitive bid. In other cases, as with the currently active 2008 DSM RFP issued in November 2008, PacifiCorp opened up bidding to many types of Class 1, 2, and 3 programs and design options.

To support the DSM procurement program, the IRP models are used for resource valuation purposes to gauge the cost-effectiveness of programs identified for procurement shortlists. In the case of the 2008 DSM RFP, system benefit valuation estimates will be provided for both Class 1 and 2 programs. For Class 2 programs, PacifiCorp will perform a "no cost" load shape decrement analysis to derive program values, similar to what was done for the 2007 IRP. (Although the supply curve modeling approach used for Class 1 and Class 2 DSM programs can provide a gross-level indication of program value, an avoided-cost type of study is necessary to pinpoint precise values suitable for cost-effectiveness assessment.)

Thermal Plants and Power Purchases

Prior to the issuance of any supply-side RFP, PacifiCorp will determine whether the RFP should be "all-source" or if the RFP will have limitations as to the amount, proposal structure(s), fuel type, or other resource attributes. The Company has lately turned to all-source RFPs in support of IRP fuel-type and technology diversity goals. For example, the 2008 all-source RFP does not specify fuel type requirements, and seeks a range of resources including renewables (greater than 10 MW), power purchase agreements, load curtailment, and QFs.

Company benchmark resources will also be determined prior to an RFP being issued and may consist of a self-build option or ownership transfer arrangement. As with other resource categories, the IRP models will be used for bid evaluation, and will reflect the latest market prices, load forecasts, regulatory policies, and other updated information as appropriate.

Distributed Generation

Distributed generation, such as CHP and distributed standby generators, were found to be cost-effective resources in the context of IRP portfolio modeling. PacifiCorp's procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative, but that is also consistent with PacifiCorp's then-current and applicable tariff filings (QF tariffs for example). As noted in the action plan, QFs of 10 MW or greater are considered eligible resources in the Company's currently active renewables RFP (2008R-1) and the 2008 All Source RFP, which was suspended in February 2009, but is expected to be reactivated later in 2009.

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed generation resources. The Company will also continue to improve representation of distributed generation resource in the IRP models.

ASSESSMENT OF OWNING ASSETS VERSUS PURCHASING POWER

As the Company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the Company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, the Company can hedge itself from the uncertainty of relying on purchasing power from others. On the negative side, owning a facility subjects the Company and customers to the risk that the cost of ownership and operation exceeds expectations, the cost of poor performance or early termination, fuel price risk, and the liability of reclamation at the end of the facility's life.

Purchasing power from another party can help mitigate the risk of cost overruns during construction and operation of the plant, can mitigate some cost and performance risks, and can avoid any liabilities associated with closure of the plant. Short-term purchased power contracts could allow the Company to defer a long term resource acquisition. On the negative side, a long-term purchase power contract relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. For example, a purchase power contract could terminate prior to the end of the term, requiring the Company to replace the output of the contract at then current market prices. In addition, the Company and customers do not receive any of the savings that result from management of the asset, nor do they receive any of the value that arise from the plant after the contract has expired. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation can affect the Company's credit ratios and credit rating.

ACQUISITION PATH ANALYSIS

The acquisition path analysis conducted for the 2008 IRP focuses on four risk areas: regulatory events, load growth, natural gas prices, and procurement delays. The sections below present contingency resource strategies for the Company to consider given significant changes in resource planning conditions tied to these four risk areas. The decision mechanism for pursuing resource strategies is the outcome of the business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions.

Regulatory Events

Table 9.3 outlines a set of resource acquisition strategies tied to regulatory "trigger" events that have been analyzed for the 2008 IRP via input assumption scenarios developed for portfolio analysis. These trigger events include (1) a fairly stringent federal RPS is enacted, (2) the federal renewable production tax credit expires or is phased out in the next 10 years, and (3) federal CO_2 regulation is enacted that results in CO_2 cost above and below PacifiCorp's assumed CO_2 trigger point, which is the CO_2 cost that yields significant changes in the resource mix. Table 9.3 also lists major risks and implementation constraints for each acquisition strategy.

The Public Utility Commission of Oregon IRP guidelines require PacifiCorp to "provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated."[56] For the 2008 IRP, PacifiCorp defined a trigger point of $45/ton (modeled as a CO_2 tax) to demarcate the point at which large changes to future resource acquisitions, and significant changes to existing fossil fuel resource operations, take place. Relative to the 2008 IRP preferred portfolio, defined with the $45/ton CO_2 cost, PacifiCorp defined a trigger point of $70/ton that indicates a reasonable point at which further significant changes to future resource acquisition, as well as major changes to existing fossil fuel resource operations, take place. The Company developed numerous portfolios based on these CO_2 cost trigger points, along with portfolios defined with even higher costs: a $100 CO_2 tax, and a $45 CO_2 tax with real escalation that reaches over $160 by 2028. (Chapter 8 provides expected cost and risk performance results as required by the Oregon IRP guidelines.) PacifiCorp also developed portfolios with no CO_2 tax for estimation of the portfolio cost of CO_2 regulations.

The likelihood that CO_2 prices would reach or exceed $70/ton depends on the confluence of both federal and state policies that have yet to be determined regarding overall strategic goals, program design, and economic sector/industry responsibilities for helping to attain long-term CO_2 reduction objectives. Specifically, governments will need to determine if policies are needed to severely restrict the use of existing fossil fuel resources, and not just discourage new coal plants from being built. Until that policy question is answered, PacifiCorp has no basis to predict whether CO_2 costs will exceed any particular level.

Even when this policy question is answered, there are many uncertainties that complicate the task of predicting how high CO_2 prices will go at this time. For example, assuming that the U.S. adopts a cap-and-trade system like the Waxman-Markey proposal, such open issues as the trajectory of annual CO_2 caps, free allowance and offset policies, state/federal interjurisdictional coor-

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[56] Public Utility Commission of Oregon, Order No. 08-339, "Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process", Guideline 8d, June 30, 2008.

dination, safety valve provisions, linkages to potential federal RPS requirements, and many other factors, will ultimately determine if CO_2 costs exceed $70/ton. Adding to the uncertainty are the following factors:

- The perceived affordability of aggressive CO_2 reduction policies in today's economic environment, which could result in a "take it slow" regulatory track
- The pace of technology advancements
- Public policies towards clean coal, advanced nuclear, and other emerging technologies that are currently controversial
- Commitments to reaching international climate change mitigation goals

Load Growth and Gas Prices

Figure 9.1 shows different resource acquisition paths based on combinations of relative decreases and increases in load growth and gas price projections given the 2008 IRP preferred portfolio input assumptions as the starting point. The acquisition paths shown are necessarily high-level, reflecting resource types rather than quantities and timing. The figure also highlights the connection with CO_2 regulations, the uncertainty of which greatly complicates any type of contingency resource planning involving other planning variables.

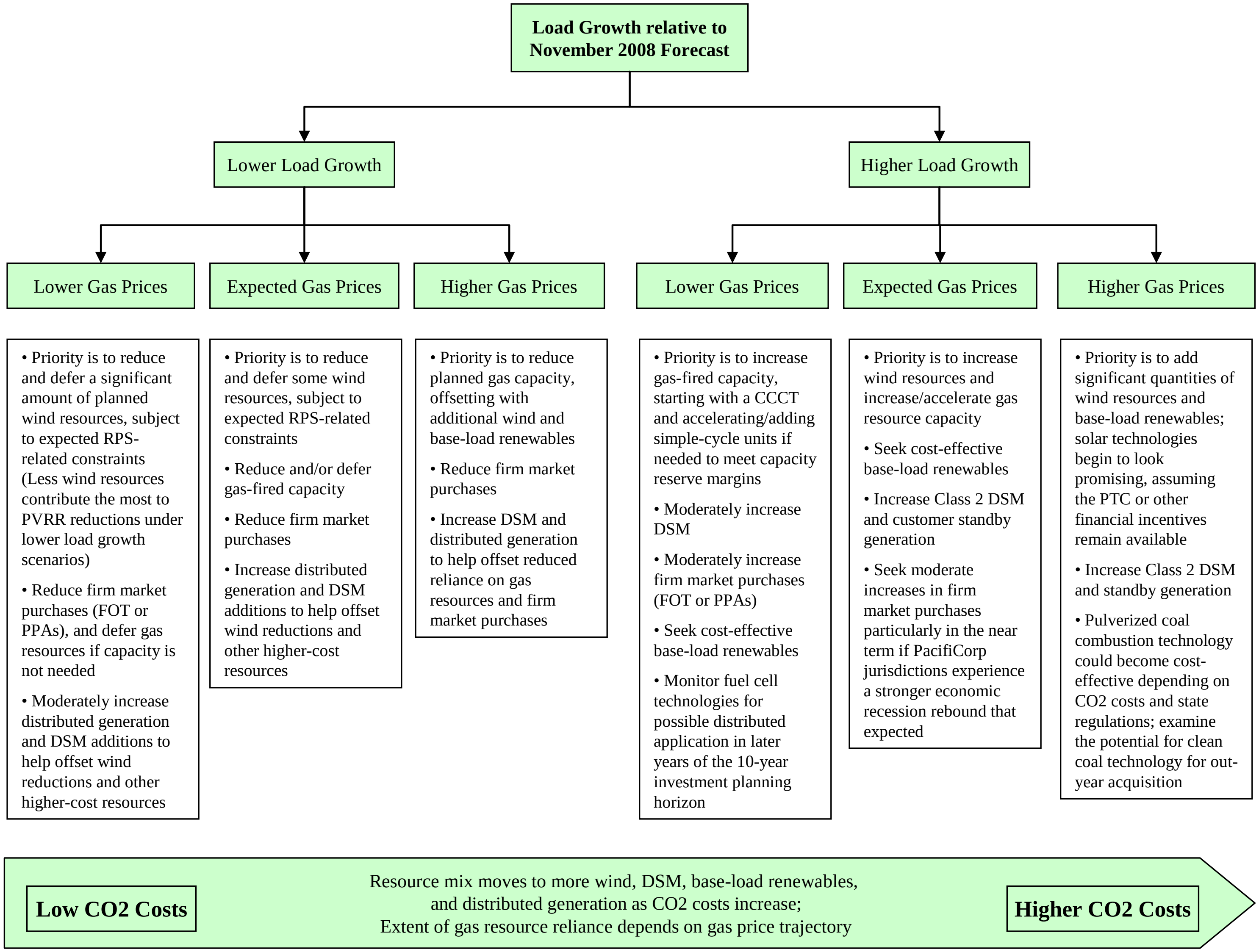
Table 9.3 – Resource Acquisition Paths Triggered by Major Regulatory Actions

Trigger Event	Planning Scenario(s)	Resource Acquisition Strategy	Risks and Constraints
Federal Renewable Portfolio Standard enacted	• A federal RPS is instituted requiring 15% of load to be met with qualifying renewables by 2020, 20% by 2020, and 25% by 2025.	• Cumulative wind capacity totals of 1,600 MW and 3,500 MW are needed by 2020 and 2025, respectively, based on the portfolio developed for the high RPS requirement scenario (case 44). • Spread incremental renewables acquisition according to an annual schedule for procurement flexibility, accelerating as necessary to account for near-term RPS requirements and to take advantage of cost-effective site availability, transmission access, and government financial incentives. • Aggressively diversify the renewables portfolio with other technologies (geothermal, solar, and biomass) as dictated by market conditions and the availability of suitable cost-effective projects. • Continue to issue renewable RFPs under PacifiCorp's shelf RFP program, and step up consideration of unsolicited proposals and multi-participant projects as opportunities arise. • Step up acquisition of demand-side management programs and distributed renewables generation to mitigate cost and procurement risks of utility-scale supply-side projects. • Adjust transmission construction plans and increase regional transmission coordination efforts to facilitate project development activity.	• Ratepayer affordability and Company financial impacts associated with a large and protracted renewables acquisition program. • Demand/supply imbalance for wind turbines and labor results in project delays and higher construction costs. • Local environmental and land use concerns/restrictions begin to adversely impact renewable project plans by increasing resource costs and forcing construction delays. • Transmission construction delays. • Increased exposure to wind integration issues and increased need for flexible resources. • Compliance burden and costs associated with multi-jurisdictional RPS requirements.
Federal renewable production tax credit expiration or cutback	• The federal renewables PTC expires within the 2013-2018 period for wind, or less likely, all renewable resources. • The federal renewables PTC is phased out over a multi-year period.	• Accelerate renewables acquisition to obtain as much as possible before the federal PTC expiration date; renewable additions were not found to be cost-effective without the federal PTC during the 2013-2018 period, given relatively low CO_2 costs.	• Acceptability of associated rate increases due to the accelerated renewables acquisition combined with other generation and transmission resource acquisitions. • Near-term impact on the Company's financial situation. • Regulatory requirements (siting and procurement) that could jeopardize

Trigger Event	Planning Scenario(s)	Resource Acquisition Strategy	Risks and Constraints
			meeting required in-service dates.
CO_2 emission compliance: low to medium cost impact	• A federal cap-and-trade program or CO_2 tax is implemented with an effective production cost impact of up to $70/ton.	• The preferred portfolio is considered a reasonable planning starting point for an uncertain CO_2 cost up to $70/ton. • The 2008 IRP preferred portfolio would be modified as an outcome of business plan/IRP portfolio modeling to reflect updated assessments of CO_2 regulations (start and trajectory of CO_2 costs), other energy policies affecting renewable energy acquisition and economics, and forward gas prices. (Natural gas prices affect the quantity of wind included in the resource portfolio. For example, comparing the preferred portfolio and the portfolio for case 8B, a 20% increase in gas prices was found to result in a 700 MW increase in wind selected by the capacity expansion model.) • Depending on expected CO_2 costs and gas prices, step up acquisition of demand-side management programs and high-efficiency distributed generation to help minimize the carbon footprint, continue to diversify the resource mix, and take advantage of any CO_2 compliance credits that may be given to these resource types. • Modify the bid evaluation process (which is based on the IRP portfolio modeling framework) to reflect updated CO_2 regulatory expectations.	• Ratepayer affordability and Company financial impacts associated with CO_2 costs that approach the upper end of the cost range ($40 to $70/ton). • Compliance burden and costs associated with multi-jurisdictional CO_2 regulatory requirements.
CO_2 emission compliance: high cost impact	• A federal cap-and-trade program or CO_2 tax is implemented with an effective production cost of $70/ton or greater.	• Acquire at least an additional 2,500 MW of wind and at least 70 MW of geothermal capacity or other base-load renewable resources, with the timing and annual amounts tied to the start of CO_2 regulations and trajectory of CO_2 costs. These minimum targets are suggested by the portfolio generated from case 17B, optimized using a $70/ton CO_2 cost. • Consider emission offset possibilities to ameli-	• Customer affordability and Company financial impacts associated with necessary resource acquisitions (including those needed to potentially replace less efficient fossil fuel plants). • Compliance safety value or emergency off-ramp provisions kick in due to high compliance costs.

Trigger Event	Planning Scenario(s)	Resource Acquisition Strategy	Risks and Constraints
		orate resource acquisition and cost risks. • Step up acquisition of higher-cost demand-side management programs and high-efficiency distributed generation to further minimize the carbon footprint. • Consider advanced high-efficiency gas generation technologies, evaluating the trade-off between greater efficiency and higher capital costs and project risks. • Aggressively pursue efficiency improvements for PacifiCorp's existing fossil fuel and hydropower plants. • For long-term resource needs and to potentially replace existing fossil fuel plants, continue to reevaluate clean coal technologies, advanced nuclear, and emerging renewable and energy storage technologies. • Modify the bid evaluation process to reflect updated CO_2 regulatory expectations.	• Demand/supply imbalance for wind turbines and labor results in project delays and higher construction costs. • Local environmental and land use concerns/restrictions begin to adversely impact renewable project plans by increasing resource costs and forcing construction delays. • Transmission construction delays. • Increased exposure to wind integration issues and increased need for flexible resources. • Compliance burden and costs associated with multi-jurisdictional requirements or poorly designed implementation.

Figure 9.1 – Resource Acquisition Paths Tied to Load Growth and Natural Gas Prices



Load Growth relative to November 2008 Forecast

Lower Load Growth

Lower Gas Prices

- Priority is to reduce and defer a significant amount of planned wind resources, subject to expected RPS-related constraints (Less wind resources contribute the most to PVRR reductions under lower load growth scenarios)
- Reduce firm market purchases (FOT or PPAs), and defer gas resources if capacity is not needed
- Moderately increase distributed generation and DSM additions to help offset wind reductions and other higher-cost resources

Expected Gas Prices

- Priority is to reduce and defer some wind resources, subject to expected RPS-related constraints
- Reduce and/or defer gas-fired capacity
- Reduce firm market purchases
- Increase distributed generation and DSM additions to help offset wind reductions and other higher-cost resources

Higher Gas Prices

- Priority is to reduce planned gas capacity, offsetting with additional wind and base-load renewables
- Reduce firm market purchases
- Increase DSM and distributed generation to help offset reduced reliance on gas resources and firm market purchases

Higher Load Growth

Lower Gas Prices

- Priority is to increase gas-fired capacity, starting with a CCCT and accelerating/adding simple-cycle units if needed to meet capacity reserve margins
- Moderately increase DSM
- Moderately increase firm market purchases (FOT or PPAs)
- Seek cost-effective base-load renewables
- Monitor fuel cell technologies for possible distributed application in later years of the 10-year investment planning horizon

Expected Gas Prices

- Priority is to increase wind resources and increase/accelerate gas resource capacity
- Seek cost-effective base-load renewables
- Increase Class 2 DSM and customer standby generation
- Seek moderate increases in firm market purchases particularly in the near term if PacifiCorp jurisdictions experience a stronger economic recession rebound that expected

Higher Gas Prices

- Priority is to add significant quantities of wind resources and base-load renewables; solar technologies begin to look promising, assuming the PTC or other financial incentives remain available
- Increase Class 2 DSM and standby generation
- Pulverized coal combustion technology could become cost-effective depending on CO2 costs and state regulations; examine the potential for clean coal technology for out-year acquisition

Low CO2 Costs

Resource mix moves to more wind, DSM, base-load renewables,
and distributed generation as CO2 costs increase;
Extent of gas resource reliance depends on gas price trajectory

Higher CO2 Costs

Procurement Delays

The main procurement risk is an inability to procure resources in the required time frame to meet the need. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2008 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or a material change in the market for fuels, materials, electricity, or environmental or other electric utility regulations, may change the Company's entire resource procurement strategy.

Possible paths PacifiCorp could take if there was either a delay in the on-line date of a resource or, if it was no longer feasible or desirable to acquire a given resource, include the following:

- Consider alternative bids if they haven't been released under a current RFP
- Issue an emergency RFP for a specific resource
- Move up the delivery date of a potential resource by negotiating with the supplier/developer
- Rely on near-term purchased power and transmission until a longer-term alternative is identified, acquired through PacifiCorp's mini-RFPs or sole source procurement
- Install temporary generators to address some or all of the capacity needs
- Temporarily drop below the 12 percent planning reserve margin
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts

MANAGING CARBON RISK FOR EXISTING PLANTS

Carbon dioxide reduction regulations at the federal and state levels would prompt the Company to continue to look for measures to lower CO_2 emissions of existing thermal plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures would be cost-effective and practical from operational and regulatory perspectives. For a cap-and-trade system, examples of factors include the allocation of free allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. To lower the emission levels for existing thermal plants, options include changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and. adoption of new technologies such as CO_2 capture with sequestration when commercially proven. Indirectly, plant carbon risk can be addressed by acquiring offsets in the form of renewable generation and energy efficiency programs. Under an aggressive CO_2 regulatory environment, early coal plant retirement becomes a tenable option. Such coal plant retirement decisions would also depend on market conditions and technological advancements that would enable cost-effective base-load power replacement or retrofit opportunities.

High CO_2 costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, but as a general rule, coal units will continue to use the existing coal technology until it is more cost-effective to replace the unit in total. A major issue is whether new technologies will be available that can be exchanged for existing coal economically.

Fuel switching and dual-fueling provide some limited opportunities to address emissions, but will require both capital investment and an understanding of the trade-offs in operating costs and risks. While these options would provide the Company a means to lower its emission profile, such options would be extremely expensive to implement unless there is a high carbon emission penalty to justify them.

USE OF PHYSICAL AND FINANCIAL HEDGING FOR ELECTRICITY PRICE RISK

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

The Company also proposes to continue to hedge the physical delivery risk inherently carried due to the volume mismatch between physical resources and physical obligations by purchasing or selling physical products in the forward through real-time markets. The purpose of purchases is to ensure adequate resources to maintain reliable delivery to the Company's obligations such as retail load. The purpose of sales is to ensure the Company's ability to economically generate and deliver electricity to wholesale purchasers.

MANAGING GAS SUPPLY RISK

Adding natural gas generating resources to PacifiCorp's system requires an understanding of the fuel supply risks associated with such resources, and the application of prudent risk management practices to ensure the availability of sufficient physical supplies and limit price volatility exposure. The risks discussed below include price, availability, and deliverability.

Price Risk

PacifiCorp manages price risk through a documented hedging strategy. This strategy involves fully hedging price risk in the nearest 12-month period and hedging less of the exposure each year beyond that through year four. Near-term prices are fully hedged to add price certainty to near term planning horizons, budgets, and rate case filings. Further out, where plans and budgets are less certain, PacifiCorp considers its most recent ten-year business plan, current market fundamentals, credit risk, collateral funding, and regulatory risk in making hedging decisions. PacifiCorp balances the benefit of hedging that plan's price assumptions with prudent risk management for its ratepayers and shareholders. PacifiCorp hedges price risk through the use of financial swap transactions and/or physical transactions. These transactions are executed with various counterparties that meet PacifiCorp's credit and contractual requirements.

Availability Risk

Availability risk refers to the risk associated with having natural gas supply in the vicinity of contemplated generating assets. PacifiCorp purchases physical supply on a forward basis achieving contractual commitments for supply. The Company also relies on its ability to purchase physical supplies in the future to meet requirements. This second approach subjects PacifiCorp to price risk resulting from swings in supply-demand balances, as well as the risk that natural gas production in a producing region ceases regardless of price. It is reasonable that a region-wide cease in production, given reserve estimates, could only be brought about by extreme and unforeseen events such as natural disaster or regulatory moratoriums on the production or consumption of natural gas—events that long-term supply commitments would not counteract. Index prices are designed to reflect the prevailing cost of supply at various delivery locations. As described above, PacifiCorp hedges its exposure to changes in those index prices, thereby allowing for procurement of supply at floating index prices or waiting to acquire supply when requirements estimates are more accurate and the premiums for longer-term commitments are no longer demanded by suppliers.

Deliverability Risk

Deliverability risk refers to the risk associated with transporting natural gas supply from supply locations to generating facilities. The 2008 IRP accounts for the cost of natural gas transportation service required to fuel gas plants, and uses existing tariff pipeline-defined transportation capacity and transportation costs in evaluating the need, timing, and location of new natural gas-fired generating plants. More specifically, the 2008 IRP uses existing maximum tariff rates for demand charges, volumetric costs, and reimbursement of fuel and lost/unaccounted natural gas. These tariff rates are developed through cost of service filings with appropriate regulators—the FERC for interstate pipelines and relevant state regulators for intrastate pipelines. By definition, rates are developed based on cost of service of existing operations, without consideration for maintenance and operations of future expansions. The result of this is that the 2008 IRP assumes that the economics of a new natural gas fired generator reflect the current cost of service for existing natural gas transportation facilities; whereas, the cost of any new natural gas transportation capacity is dependent on the volumetric size of the new capacity, and prevailing costs of construction, maintenance, and operations (e.g. steel, labor, financing).

Also, the 2008 IRP accounts for the availability of natural gas transportation service required to fuel new electricity generating facilities. In selecting a gas-fired resource, the implicit assumption is made that natural gas transportation infrastructure exists or will be built. This is a reasonable assumption if one further assumes that the construction of new pipeline facilities is a function of cost, which is addressed above.

PacifiCorp manages this transportation cost through two transaction types: transportation service agreements and delivered natural gas purchases:

- PacifiCorp enters into transportation service agreements that offer PacifiCorp the right to ship natural gas from prolific production basins or liquidly traded “hubs” to generating assets. Natural gas hubs exist where a large volume of production is gathered and delivered into a large interstate pipeline or where large pipelines intersect. These hubs lead to liquidly traded markets as the movement of gas from one transporting pipeline to another lead to a large number of willing buyers and sellers.

- PacifiCorp purchases natural gas delivered to generating plants and/or hubs. This approach pushes the deliverability risk to the supplier by contractually committing it to making necessary supply and/or transportation arrangements.

PacifiCorp is confident that the risks associated with fueling current and prospective natural gas fueled generation can be effectively managed. Risk management involves ongoing monitoring of the factors that affect price, availability, and deliverability. While prudence warrants the monitoring of many factors, some issues that PacifiCorp needs to pay particular attention to, given today's market, include the following:

- Potential counterparties need to be continually monitored for their creditworthiness and long-term viability, especially given the current economic downturn.
- Environmental concerns could impact natural gas prices, particularly given the prospects of a CO_2 cap-and-trade or tax program. PacifiCorp continues to monitor the regulatory environment and its potential impact on natural gas pricing.
- As production grows in the Rocky Mountains, so does the transportation infrastructure. PacifiCorp continues to monitor this activity for risks and opportunities that new pipeline infrastructure may yield.

TREATMENT OF CUSTOMER AND INVESTOR RISKS

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

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the 2008 IRP. Capital expenditures continue to increase, driven by the need for infrastructure investment to support load growth and maintain reliable electricity supplies, and the effects of cost inflation. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risk of this type facing PacifiCorp continues to be government actions related to CO_2 emissions. This scenario risk relates to the uncertainty in predicting the scope, timing, and cost impact of CO_2 emission compliance rules. Chapter 3 frames this issue in terms of the impacts of CO_2 policy and cost uncertainty on natural gas and wholesale electricity prices, and consequent dramatic cost impacts to consumers.

To address this risk, the Company decided in 2007 that acquiring a coal plant was not a viable resource option until regulatory clarity concerning CO_2 costs and technology/fuel policies is obtained. While coal plants are allowed as eligible resources for competitive procurements that solicit base-load resources, PacifiCorp evaluates all bid resources using a range of CO_2 prices consistent with the scenario analysis methodology adopted for the Company's IRP portfolio evaluation process. Further, coal resources must comply with applicable existing state CO_2 compliance regulations. The risk of potential future CO_2 costs is therefore fully accounted for in resource planning and procurement decision-making. The Company's efforts to acquire wind and DSM resources also serve as effective CO_2 risk mitigation measures.

10. TRANSMISSION EXPANSION ACTION PLAN

INTRODUCTION

Since the original announcement of Energy Gateway in May 2007 and as discussed further in Chapter 4, PacifiCorp has emphasized that significant infrastructure of new transmission capacity is needed to adequately serve PacifiCorp's existing and future loads. The Company's position has not changed in this regard and still requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South) of new transmission capacity to adequately serve its customers load and growth needs for the long-term.

PacifiCorp also recognized in its original announcement the need and benefits of potentially "upsizing" the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors, potential to reduce environmental impacts, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity.

PacifiCorp still believes there are short-term and long-term benefits for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp is proceeding with efforts regarding planning, rating, and permitting requirements for the Energy Gateway Program that facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need and construction timing.

PacifiCorp is moving forward with the expansion plan that will construct transmission lines and substations required to provide 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads.

In addition, several main grid reinforcement projects that are complementary to the Energy Gateway program are scheduled for completion over the next several years. They are described after the Energy Gateway segments.

High-level descriptions of the Energy Gateway segments and Company planning activities are outlined below. In-service dates are based on optimal timing of transmission needs and best efforts to complete construction. The dates reflect the most recent Gateway planning assessment, which occurred after the completion of IRP modeling described in the preceding chapters. Gateway plan modifications will be incorporated in PacifiCorp's 2010 business plan and the 2008 IRP update. In-service dates are subject to timing shifts based on permitting, environmental approvals, and construction schedules.

GATEWAY SEGMENT ACTION PLANS

Walla Walla to McNary – Segment A

Originally planned as a single circuit 230 kV transmission line approximately 56 miles in length between Wall Walla, Washington and Umatilla, Oregon that connects existing substations at Walla Walla, Wallula, and McNary. The initial target completion date was 2010; however, additional information became available in early 2009 that prompted the decision to defer moving forward with the current project scope in 2009.

PacifiCorp acquired the Chehalis generation plant in late 2008 and on February 13, 2009 redirected 470 MW of transmission rights to the Mid Columbia area. Existing transmission rights between Yakima and Walla Walla allow a portion of the Chehalis resources to cover any Walla Walla short resource position. This minimizes any net power costs benefits from the prior economics that showed Hermiston generation located in Oregon displacing Mid-Columbia purchases and serving Yakima and Walla Walla loads during short supply periods.

Over the next six to twelve months, PacifiCorp is actively participating in transmission plans and system rating processes impacting the Northwest, and these plans are expected to mature and possibly influence PacifiCorp's Westside Plan. At that time, the Company will determine any additional transmission needed in the Walla Walla / McNary area. PacifiCorp will continue to evaluate the project and incorporate the analysis with regional transmission needs.

Populus to Terminal – Segment B

A double circuit 345 kV line that will run approximately 135 miles from a new substation (Populus) near Downey, Idaho to the existing Terminal Substation near Salt Lake International Airport west of Salt Lake City, Utah. When completed in 2010, this segment will improve reliability along a critical transmission corridor (Path C) and provide additional transfer capability of energy resources both south bound and north bound. It will also provide a vital link for Energy Gateway path ratings.

Mona to Limber to Oquirrh – Segment C

A single circuit 500 kV line that will run approximately 65 miles between the existing Mona Substation in central Utah to a future substation called Limber in the Tooele Valley, west of Salt Lake City, Utah. It will also include a double circuit 345 kV line that will run approximately 21 miles between the future Limber Substation to an existing substation called Oquirrh in the Salt Lake valley. When completed in 2012, it provides a critical northbound path for additional resource whether internally generated or purchased through market transactions. It will also provide a vital link for reliability and Energy Gateway path ratings.

Oquirrh to Terminal

A double circuit 345 kV line that will run approximately 14 miles between the Oquirrh Substation to an existing Terminal Substation near Salt Lake International Airport west of Salt Lake City, Utah. When completed in 2012, it will add operational flexibility to the bulk electrical system, improved reliability and will provide a vital link for Energy Gateway path ratings.

Windstar to Aeolus to Bridger to Populus – Segment D

Part of Energy Gateway West, it is comprised of two single circuit 230 kV lines that will run approximately 82 and 72 miles respectively between the recently constructed Windstar Substation in eastern Wyoming to a new substation called Aeolus near Medicine Bow, Wyoming. It will continue as a 500 kV single circuit line that will run approximately 141 miles from Aeolus Substation to a new annex substation near the existing Bridger Substation near Jim Bridger Power Plant in western Wyoming.

The last section will connect the new annex substation located near Bridger Substation to the Populus Substation that is being constructed as part of the Populus to Terminal segment. When completed in 2014, the entire segment will move wind or other resources from eastern Wyoming to a critical hub (Populus) located near Downey, Idaho. The Populus Substation is the intersection substation for Gateway West and Gateway Central.

Populus to Hemingway – Segment E

Two single circuit 500 kV lines that will run approximately 135 and 149 miles respectively between the Populus Substation and the existing Midpoint Substation. One of the lines will also connect the existing Borah Substation between Populus and Midpoint. The segment will continue as a single circuit 500 kV line for approximately 126 miles from Midpoint Substation to a new Hemingway Substation located south of Boise on the south side of the Snake River between the towns of Melba and Murphy. When completed in 2016 the segment will connect resources located in eastern Wyoming and Gateway Central to load centers further west. It will also allow the Company to maintain reliable electric service in the Western Interconnection.

Aeolus to Mona – Segment F

A single-circuit 500 kV line that runs approximately 395 miles between the Aeolus Substation (constructed as part of Gateway West) and the Mona Substation (expanded as part of Gateway Central). When completed in 2017 the segment will connect Gateway West and Gateway Central providing operational flexibility for the bulk electric network, reliability and supports path ratings for each segment.

Sigurd to Red Butte – Segment G

A single circuit 345 kV line that runs approximately 160 miles connecting the existing Sigurd Substation located in central Utah to another existing substation called Red Butte Substation located in southwest Utah. When completed in 2014, it provides a critical path to meet load obligations, increase export capability and to maintain transmission capacity on TOT2C for contracted point to point service. Specific routing alternatives are currently being considered in the permitting and ratings processes.

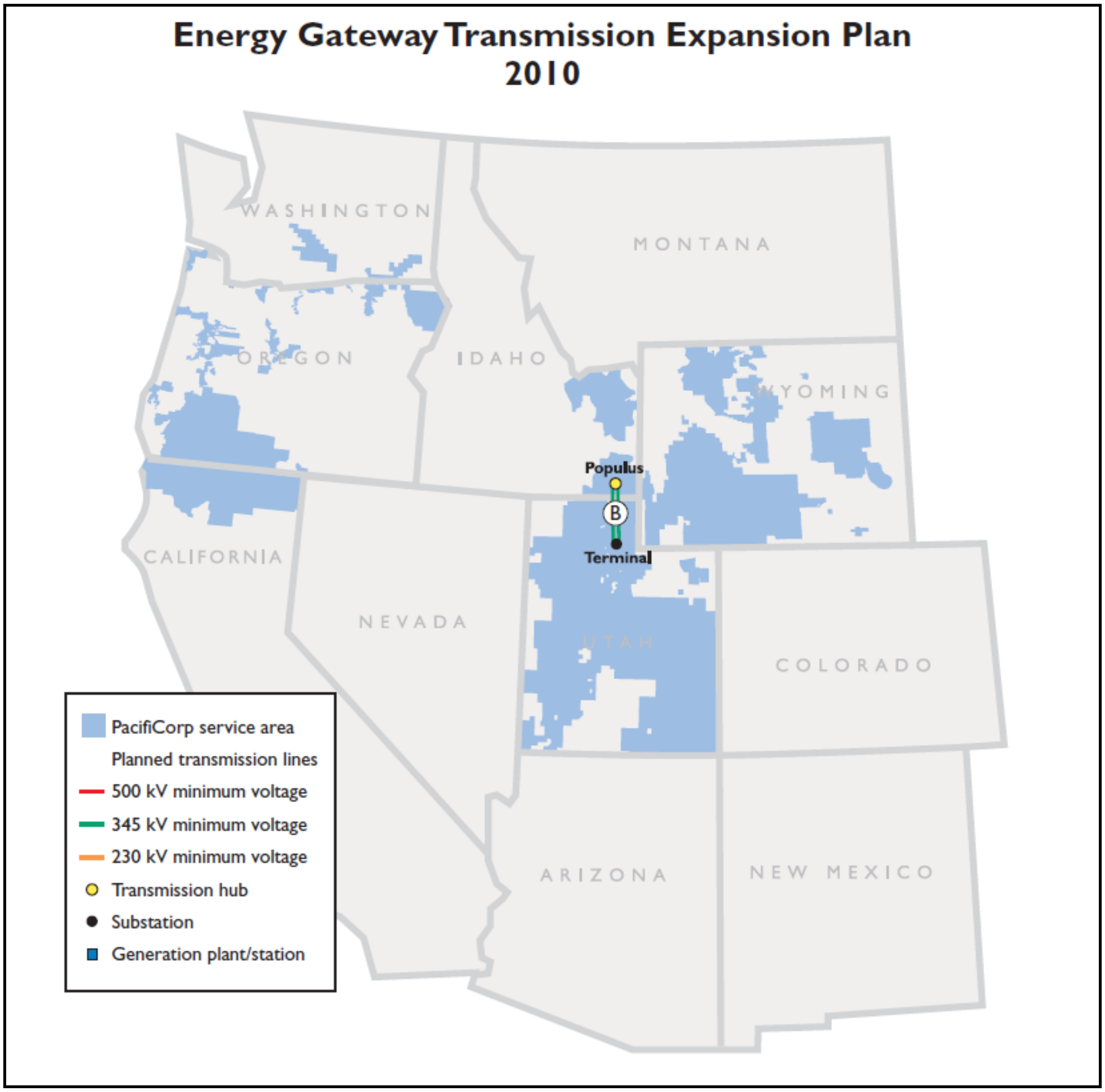
Segment G originally included a single circuit 500 kV line from Red Butte Substation in Utah to Crystal Substation in Nevada. The transmission line is being deferred for further review due to the fact that existing customer forecasted needs are anticipated to be met without its construction. Studies show bi-directional flows to markets are met by installing upgrades at Harry Allen Substation in Nevada and other system reinforcements in 2014. Although the segment is not needed at this time for the 1,500 MW Gateway South expansion plan, the line segment and related substation upgrades will be required for Energy Gateway South to obtain the next incremental rating of 3,000 MW total.

Construction of the planned transmission segments by estimated in-service dates and additional megawatt capacity are shown in the following sequence of maps. Delivery of the segments by the calendar years shown are particularly critical for Gateway West from Windstar to Populus, Gateway Central from Mona to Terminal, and Gateway South from Sigurd to Red Butte, due to the IRP preferred portfolio reliance on available transmission.

Maintaining sufficient transmission capacity for southwest Utah loads and maintaining contracted point-to-point transmission service prior to the Sigurd to Red Butte - Segment G addition in 2014 will require several substation upgrades. The Sigurd to Red Butte project is being considered with other alternatives to meet the requirements in SW Utah. In 2010, PacifiCorp is planning to install additional station equipment at Harry Allen Substation, Pinto Substation and Three Peaks Substation and in 2011 additional station equipment is being installed at Red Butte Substation.

Additional main grid reinforcement projects also includes upgrades to TOT2C path at Harry Allen Substation in Nevada, which will increase bi-directional flows to markets in the Desert Southwest needed in 2014.

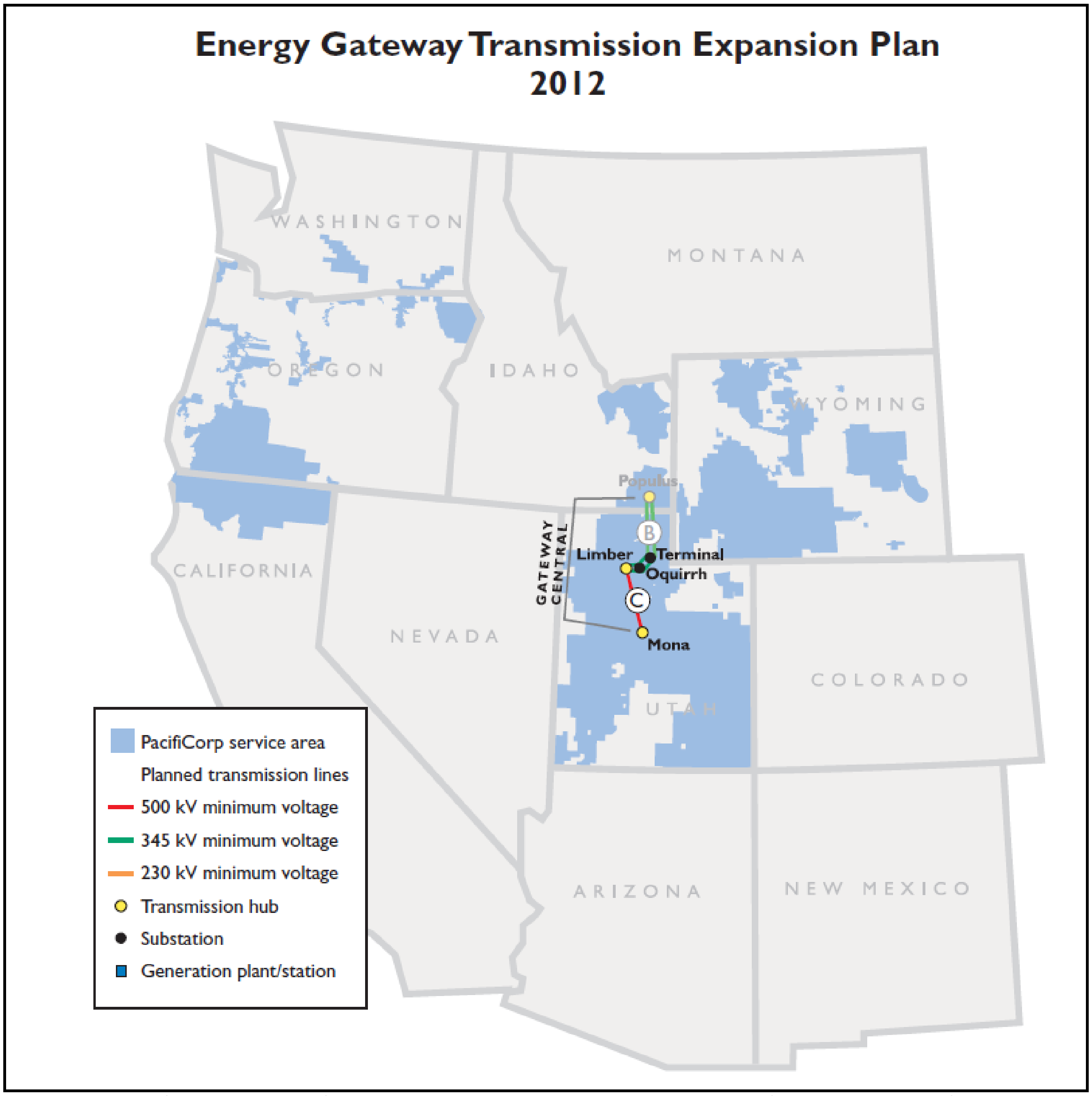
Figure 10.1 – Energy Gateway 2010 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
B	Populus - Terminal	345 kV double circuit	700 MW	1400 MW

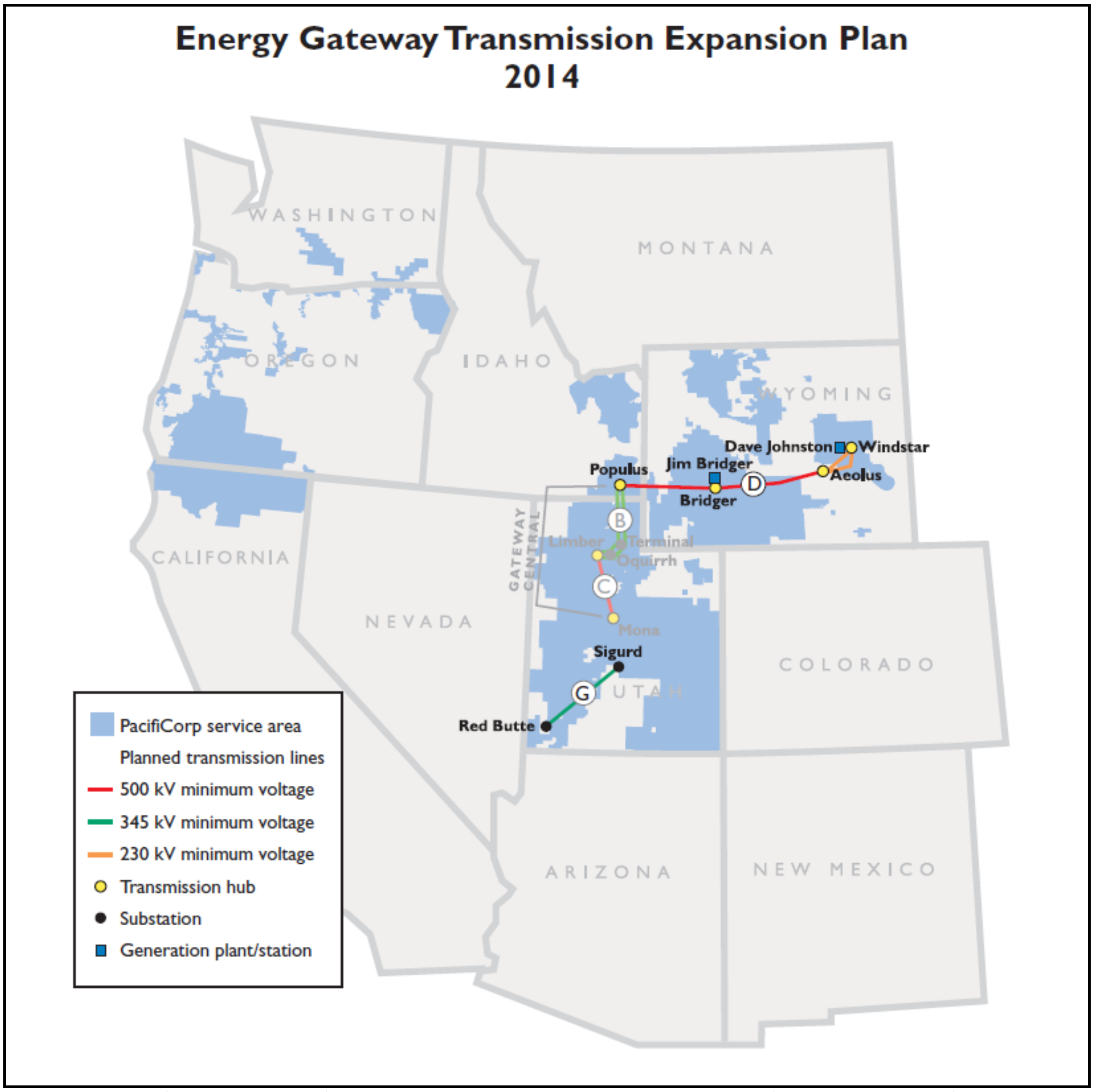
Figure 10.2 – Energy Gateway 2012 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
C	Mona – Limber Limber – Oquirrh	500 kV single circuit/ 345 kV double circuit	700 MW	1500 MW
Other	Oquirrh – Terminal	345 kV double circuit	700 MW	1500 MW

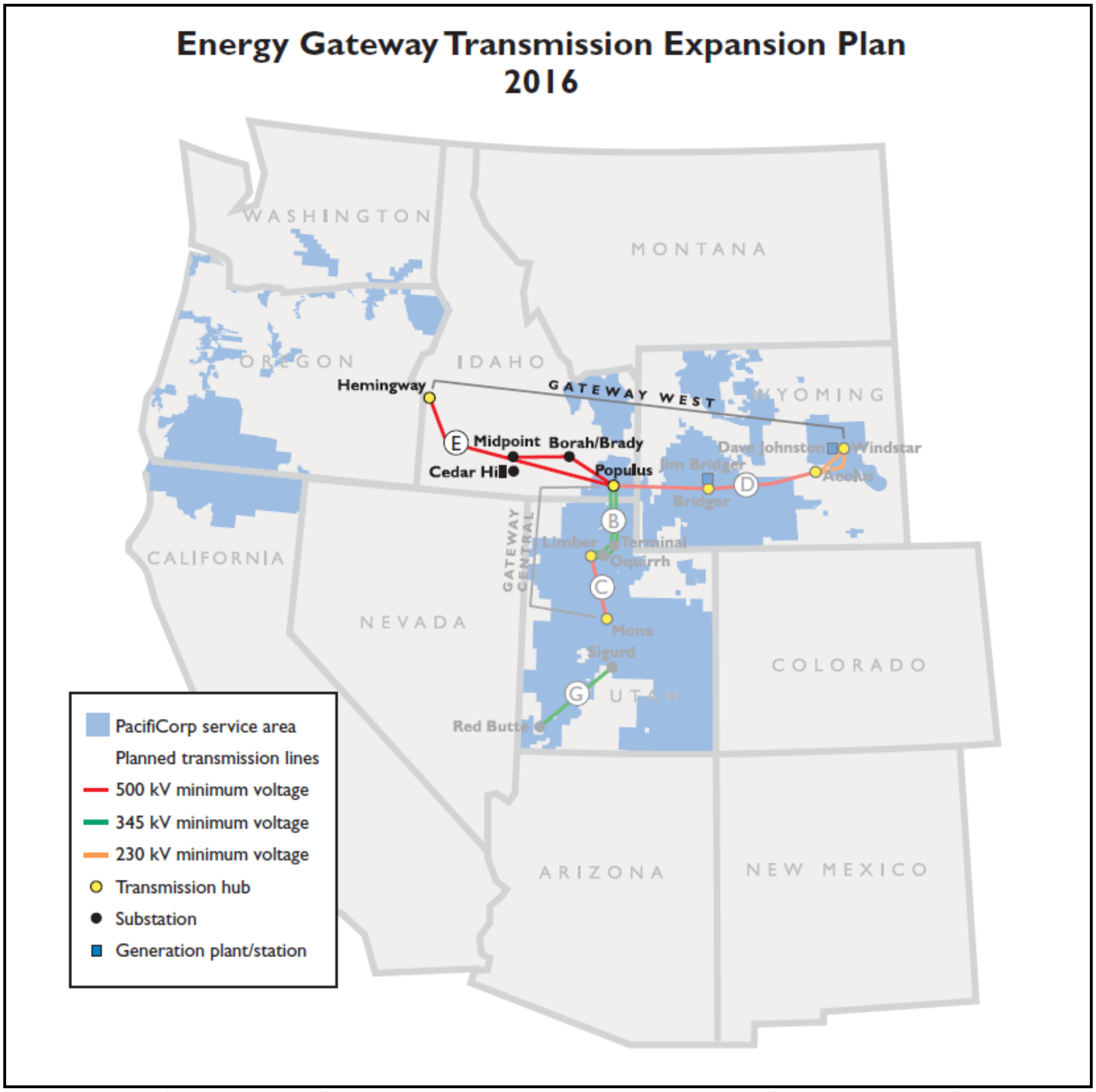
Figure 10.3 – Energy Gateway 2014 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
D	Windstar – Aeolus Aeolus –Bridger Bridger - Populus	2-230 kV single circuits 500 kV single circuit 500 kV single circuit	700 MW 700 MW 700 MW	700 MW 1500 MW 1500 MW
G	Sigurd – Red Butte	345 kV single circuit	600 MW	600 MW
Various	Various upgrades at Harry Allen to increase capacity to the Desert Southwest	TOT2C Path	600 MW	600 MW

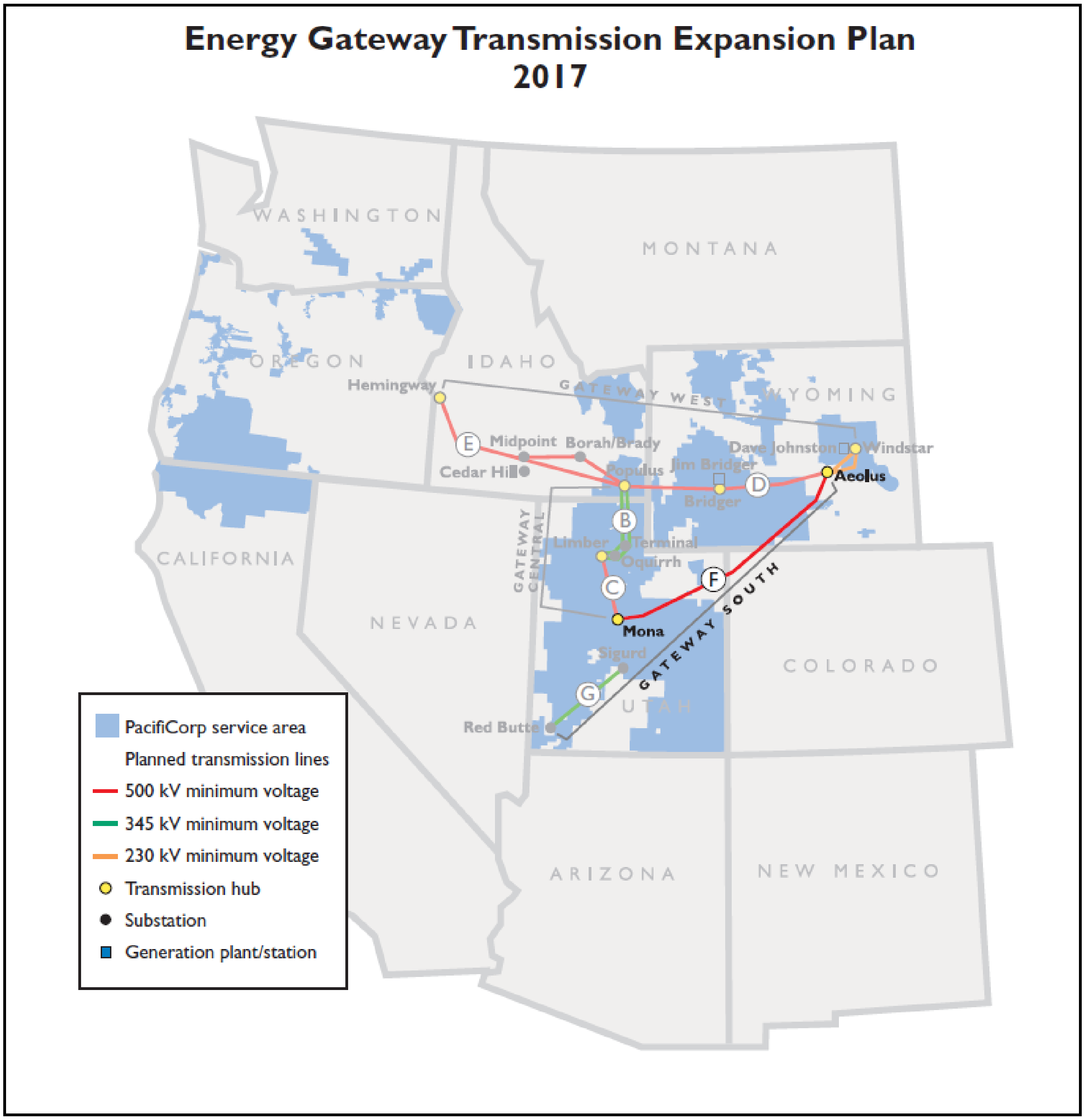
Figure 10.4 – Energy Gateway 2016 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
E	Populus – Borah – Midpoint	500 kV single circuit	700 MW	1500 MW
E	Populus – Midpoint – Hemingway	500 kV single circuit	700 MW	1500 MW

Figure 10.5 – Energy Gateway 2017 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
F	Aeolus – Mona	500 kV single circuit	1500 MW	1500 MW

Westside Plan / Red Butte – Crystal

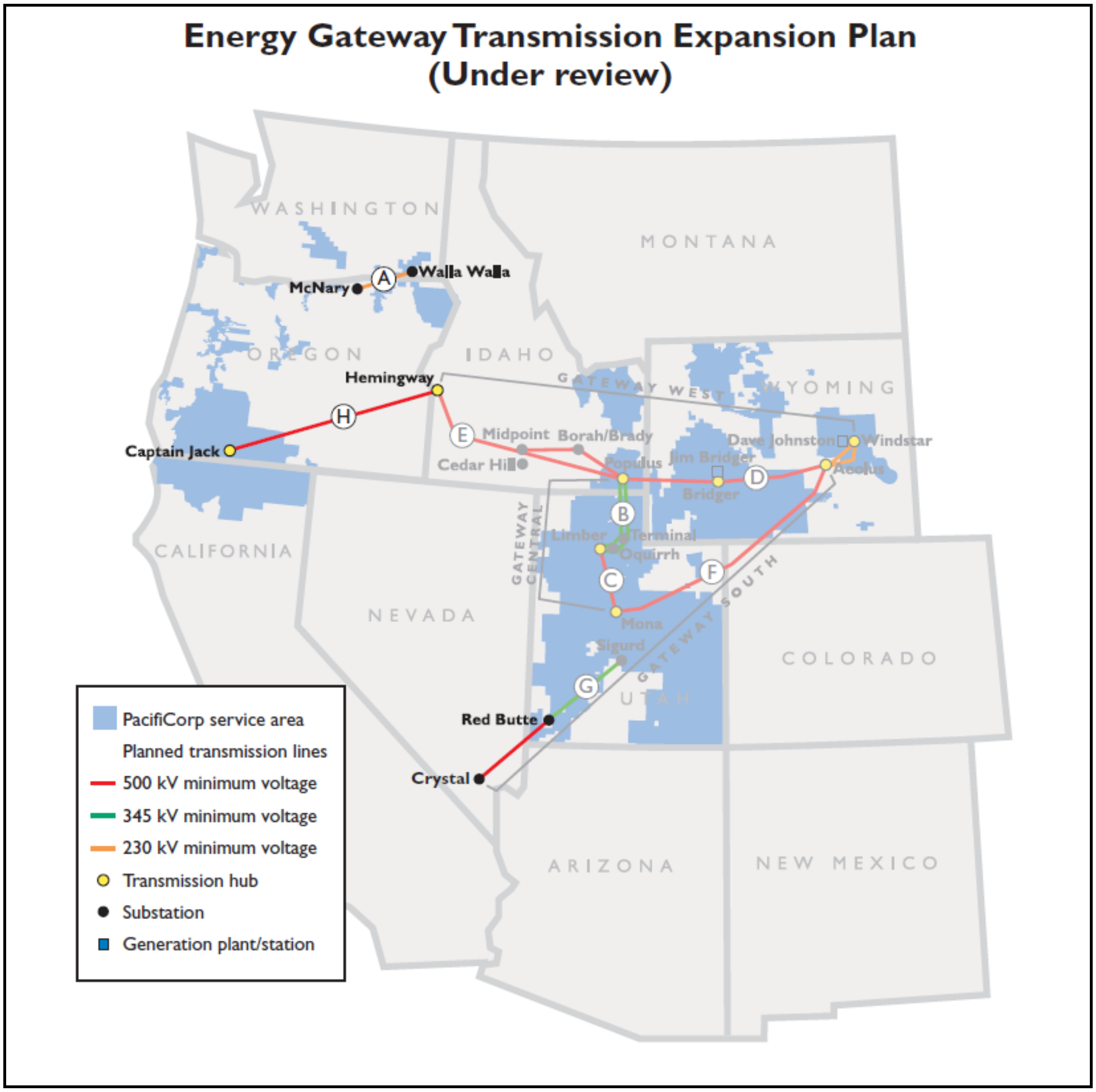
The west side of PacifiCorp's system (Washington, Oregon and California) is well integrated with Avista Energy, Bonneville Power Administration, Portland General Electric, and, to a lesser degree, interconnections to the California Independent System Operator. Additionally, several regional projects have been proposed to interconnect in the northwest (California to Canada Transmission, Boardman to Hemingway, Southern Crossing, West of McNary, I-5 reinforcement, Devils Gap, Northern Lights and others).

PacifiCorp's Walla Walla to McNary single circuit 230 kV line and Hemingway to Captain Jack single circuit 500 kV line will be planned and coordinated with other regional projects to provide the best solution for customers and the region. Ultimate configuration and timing of PacifiCorp's Walla Walla to McNary and Hemingway to Captain Jack projects is an action item resulting from this IRP.

The Red Butte to Crystal single circuit 500 kV line was originally planned for 2012 but was deferred due to other Energy Gateway/system reinforcement projects providing sufficient transmission capacity to meet customer requirements. The line will be reevaluated as future needs are identified.

The map shown below shows the geographic context of the segments described above.

Figure 10.6 – Westside Plan / Red Butte – Crystal



Note: This map generally reflects key expansion segments under review. It does not reflect all the segments that are necessary to for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
A	Walla Walla – McNary	230 kV single circuit	400 MW	400 MW
G	Red Butte - Crystal	500 kV single circuit	TBD	1500 MW
H	Hemingway – Captain Jack	500 kV single circuit	TBD	1500 MW

Let's turn the answers on.

2008

Integrated Resource Plan

Volume II - Appendices

PACIFICORP
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May 28, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2008 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: Foot 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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APPENDIX A – DETAIL CAPACITY EXPANSION RESULTS

This appendix provides additional System Optimizer results for each of the cases studied during the 2008 IRP. A prior version of this appendix was provided to IRP public participants in December 2008 and later updated. New to this appendix are the additional "B-Series" cases and their respective charts and tables which are at the end of each section of this appendix. The follow bullets layout this appendix;

Reference Information

- Case Definition List
- Resource Name List

Charts and Pivot Summaries

- Portfolio Area Charts
    - "B-Series" Area Charts
- Core Cases – Pivot Summary
    - 2009 to 2013
    - 2014 to 2020
    - 2021 to 2028
- Core Cases – 20-Year Summary by Scenario Variable
    - CO_2 Tax Level
    - Gas Price Curves
    - Load Growth Level
- Core Cases – Resource Type Summary

Detail Portfolio Data

- Portfolio RPS Summary
- Portfolio Summary Tables
- B Series Delta Summary Comparison

Table A.1 – Core Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Core Cases										
1	CO2 tax	$0	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
2	CO2 tax	$0	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
3	CO2 tax	$0	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
4	CO2 tax	$45	Low	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
5	CO2 tax	$45	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
6	CO2 tax	$45	Low	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
7	CO2 tax	$45	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
8	CO2 tax	$45	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
9	CO2 tax	$45	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
10	CO2 tax	$45	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
11	CO2 tax	$45	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
12	CO2 tax	$45	Medium	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
13	CO2 tax	$45	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
14	CO2 tax	$45	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
15	CO2 tax	$45	High	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
16	CO2 tax	$70	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
17	CO2 tax	$70	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
18	CO2 tax	$70	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
19	CO2 tax	$70	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
20	CO2 tax	$70	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
21	CO2 tax	$70	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
22	CO2 tax	$70	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
23	CO2 tax	$100	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
24	CO2 tax	$100	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
25	CO2 tax	$100	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
26	CO2 tax	$100	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
27	CO2 tax	$100	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
28	CO2 tax	$100	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
29	CO2 tax	$100	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded

Table A.2 – Sensitivity and Business Plan Reference Case Definitions

Case #	**CO2 Compliance Strategy and Costs**		**Base Gas Cost (Prior to CO2 compliance impact adjustments)**		**Load Growth**	**Renewable Portfolio Standard**	**Clean Baseload Plant Available**	**Plant Construction Cost**	**Planning Reserve Margin**	**Class 3 DSM for Peak Load Reduction**
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Real CO2 Cost Escalation with Changing Load Growth										
30	CO2 tax	$45 (2013) to $163 (2028)	Medium	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
31	CO2 tax	$45 (2013) to $163 (2028)	High	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
National CO2 Cap-and-Trade Policy: Lieberman-Warner "Climate Security Act of 2008" (SB 3036, introduced May 20, 2008)										
32	Cap-and-Trade	Market	Medium	Oct-08	Medium	Base	Base	Base	12%	Excluded
High-Cost Outcome										
33	CO2 tax	$100	High	Jun-08	High	Base	Late	High	12%	Excluded
Clean Base-Load Generation Availability										
34	CO2 tax	$45	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
35	CO2 tax	$45	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
36	CO2 tax	$70	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
37	CO2 tax	$70	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
High Plant Construction Costs										
38	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	High	12%	Excluded
39	CO2 tax	$45	High	Jun-08	Medium	Base	Base	High	12%	Excluded
Oregon CO2 Reduction Targets (from HB 3543) Applied as System-wide Hard Caps										
40	Hard Cap	N/A	Medium	Jun-08	Medium	Base	Base	Base	12%	Excluded
Alternative Planning Reserve Margin Level (15%)										
41	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
42	CO2 tax	$70	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
43	CO2 tax	$100	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
Alternative renewable policy assumptions										
44	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	High	Base	Base	12%	Excluded
45	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Base/PTC expires	Base	Base	12%	Excluded
Business Plan Reference Cases										
46	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Fixed RPS-compliant wind schedule	Base	Base	12%	Excluded
47	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Optimized RPS-compliant renewables	Base	Base	12%	Excluded
Class 3 DSM For Peak Load Reduction										
48	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	12%	Included

Table A.3 – Resource Name and Description

Plant	**Side**	**Description**
CCS Hunter3	East	IRP Carbon Capture & Sequestration Hunter 3
Coal Plant Turbine Upgrades	East	Coal Plant Turbine Upgrades
UT IGCC CCS	East	IRP Utah Integrated Gasificafication Combine Cycle Carbon Capture & Sequestration
UT Pulverized Coal	East	IRP Utah Pulverized Coal
UT Pulverized Coal CCS	East	IRP Utah Pulverized Coal Carbon Capture & Sequestration
WY IGCC CCS	East	IRP Wyoming Integrated Gasificafication Combine Cycle Carbon Capture & Sequestration
WY Pulverized Coal	East	IRP Wyoming Pulverized Coal
WY Pulverized Coal CCS	East	IRP Wyoming Pulverized Coal Carbon Capture & Sequestration
CCS Bridger1	West	IRP Carbon Capture & Sequestration Bridger 1
CCS Bridger2	West	IRP Carbon Capture & Sequestration Bridger 2
CCCT F 1x1	East / West	Combine Cycle Combustion Turbine F-Machine 1x1 with Duct Firing
CCCT F 2x1	East / West	Combine Cycle Combustion Turbine F-Machine 2x1 with Duct Firing
CCCT G 1x1	East / West	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing
CCCT H 2x1	East / West	Combine Cycle Combustion Turbine H-Machine 2x1 with Duct Firing
ICE	East / West	Internal Combustion Engine
IC Aero	East / West	Simple Cycle Combustion Turbine Intercooled Aero
SCCT Aero	East / West	Simple Cycle Combustion Turbine Aero Dérivative
SCCT Frame	East / West	Simple Cycle Combustion Turbine Frame
Geothermal	East / West	Geothermal (East-Blundell,East-Greenfield, West-Greenfield)
Nuclear	East / West	Nuclear
Battery Storage	East / West	Battery Storage
Utility Biomass	East / West	Utility Biomass
CAES	East / West	Compressed Air Energy Storage
CHP - Biomass	East / West	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	East / West	Combined Heat and Power - Reciprocating Engine
CHP - Kern River	East / West	Combined Heat and Power - Kern River (Recovered Energy Generation)
CHP - Other	East / West	Combined Heat and Power - Other
Distributed Standby Generation	East / West	Distributed Standby Generation
Fuel Cell	East / West	Fuel Cell
Pump Storage	East / West	Pump Storage
Wave	West	Wave (Hydrokinetic)
Solar	East / West	Solar Concentrating (PV)
Solar Gas	East / West	Solar Concentrating (PV, Natural Gas Backup)
Solar Storage	East / West	Solar Concentrating (Trough, Thermal Storage)
Micro Solar	East / West	Micro Solar - Roof-top PV
DSM, Class 1, UT-Coolkeeper	East / West	DSM - Class 1 - Utah Coolkeeper
DSM, Class 1, [Bubble]-Curtail *	East / West	IRP DSM Class 1 *[Bubble] Curtailment*
DSM, Class 1, [Bubble]-DLC-Com *	East / West	IRP DSM Class 1 *[Bubble] Direct Load Control-Commercial*

Plant	**Side**	**Description**
DSM, Class 1, [Bubble]-DLC-RES *	East / West	IRP DSM Class 1 *[Bubble] Direct Load Control-Residential*
DSM, Class 1, [Bubble]-DLC-WH *	East / West	IRP DSM Class 1 *[Bubble] Direct Load Control-Water Heater*
DSM, Class 1, [Bubble]-Irrigate *	East / West	IRP DSM Class 1 *[Bubble] Irrigation*
DSM, Class 1, [Bubble]-Sch-TES *	East / West	IRP DSM Class 1 *[Bubble] Scheduled-Thermal Energy Storage*
DSM, Class 3, [Bubble]-CPP-CI *	East / West	IRP DSM Class 3 *[Bubble] Critical Peak Pricing-Small commercial*
DSM, Class 3, [Bubble]-CPP-RES *	East / West	IRP DSM Class 3 *[Bubble] Critical Peak Pricing-Residential*
DSM, Class 3, [Bubble]-DemandB *	East / West	IRP DSM Class 3 *[Bubble] Demand Buyback-Ind/Comm*
DSM, Class 3, [Bubble]-RTP-CI *	East / West	IRP DSM Class 3 *[Bubble] Time-of-Use - Small Commercial*
DSM, Class 3, [Bubble]-TOU-RES *	East / West	IRP DSM Class 3 *[Bubble] Time-of-Use - Residential*
DSM, Class 2, [Bubble]	East	DSM, Class 2, - *Goshen, Utah, Total Wyoming, Washington, West Main, Yakima*
Wind, *[Bubble]*, 24	East / West	*[Bubble]* Wind 24% Capacity Factor
Wind, *[Bubble]*, 29	East / West	*[Bubble]* Wind 29% Capacity Factor
Wind, *[Bubble]*, 35	East / West	*[Bubble]* Wind 35% Capacity Factor
Wind, Project I	East	Wind, Project I
Wind, Project II	East	Wind, Project II
Wind, Duke Energy PPA	East	Wind, Duke Energy PPA
Wind, HighPlains	East	Wind, High Plains
Wind PPA	West	Wind Power Purchase Agreement
2012 RFP Lake Side	East	2012 RFP Lake Side 2 ***
East PPA	East	East Power Purchase Agreement
Coal & Gas Capacity Upgrades	East	Coal & Gas Capacity Turbine Upgrades
Coal Plant Turbine Upgrades	West	Coal Plant Turbine Upgrades
Blundell 3	East	Blundell Geothermal 3 (Expansion)
Swift Hydro Upgrades	West	Swift Hydro Upgrades
FOT *[Market Bubble]* Q3 **	East	Front Office Transaction - *3rd Quarter HLH Product*
FOT *[Market Bubble]* Flat **	East	Front Office Transaction - *Flat Annual Product*
Growth Resource *[Bubble]*	East / West	**Growth Resource (Goshen, Utah North, Wyoming, Walla Walla, West Main, Yakima)**

Notes on Market and Topology Bubbles:

Please see the Transmission Topology chart for the "bubbles" used for location of modeled resource options.

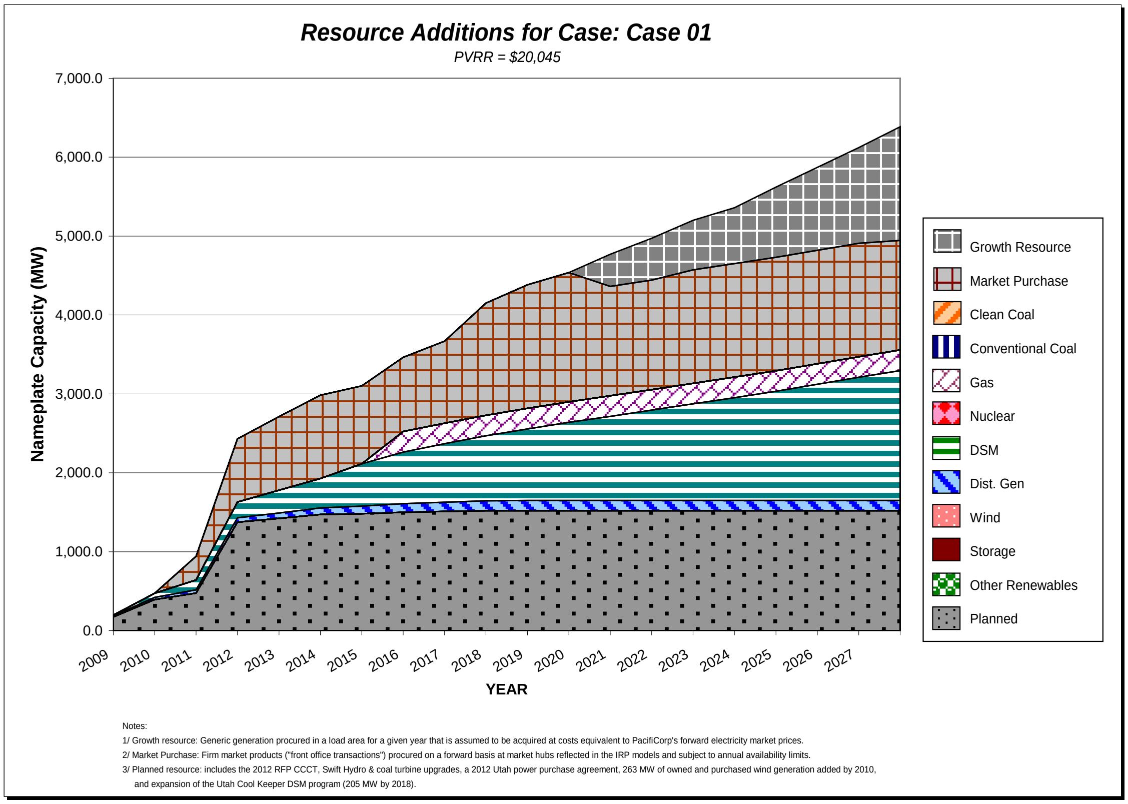
**** Topology Bubbles:** Goshen (GO), Utah (UT), WYAE (Wyoming Aeolus), MC (Mid-Columbia), WM (West Main), WW (Walla Walla), YA (Yakima)*

WYSW (Wyoming Southwest)

***** Market Bubble:** Mead, Mona, Utah, California Oregon Border, Mid-Columbia, West Main, Nevada-Utah Border (NUB)*

*** The 2012 RFP Lake Side 2 resource option was removed in February 2009 during the planning process.

AREA CHARTS: PORTFOLIO CAPACITY ADDITIONS BY RESOURCE TYPE



Resource Additions for Case: Case 01

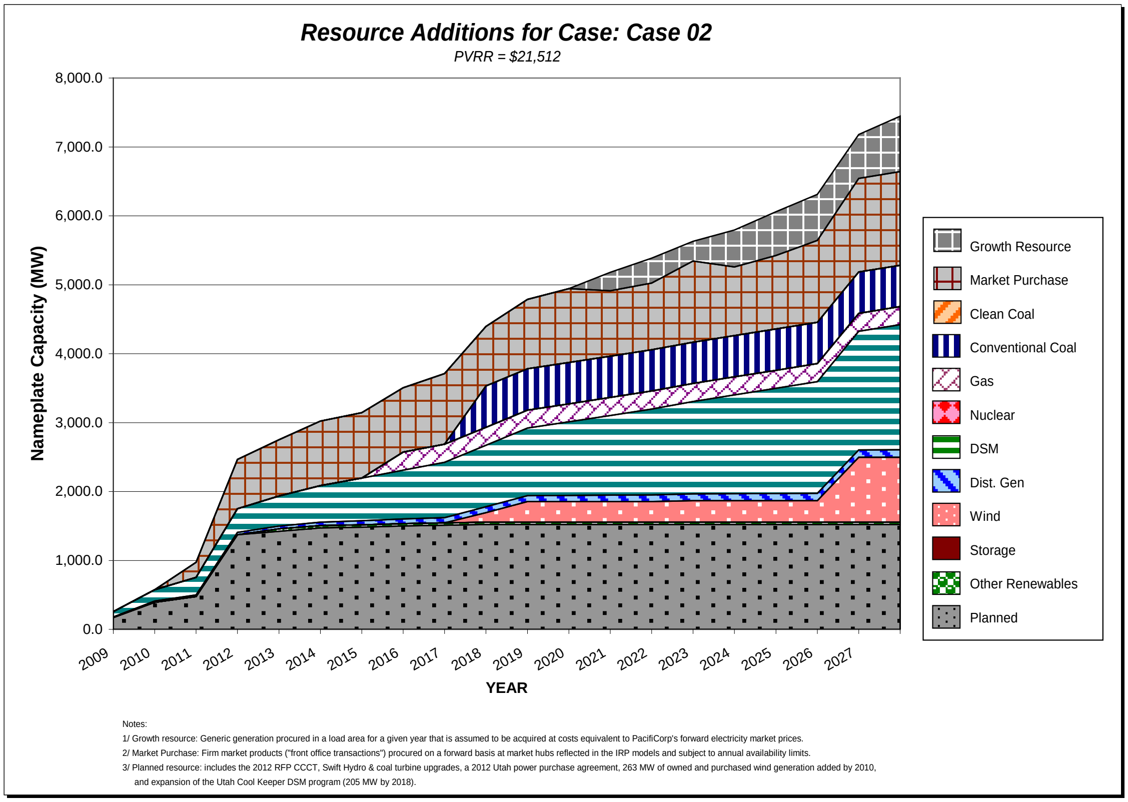
PVRR = $20,045

Notes:

1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 02

PVRR = $21,512

Notes:

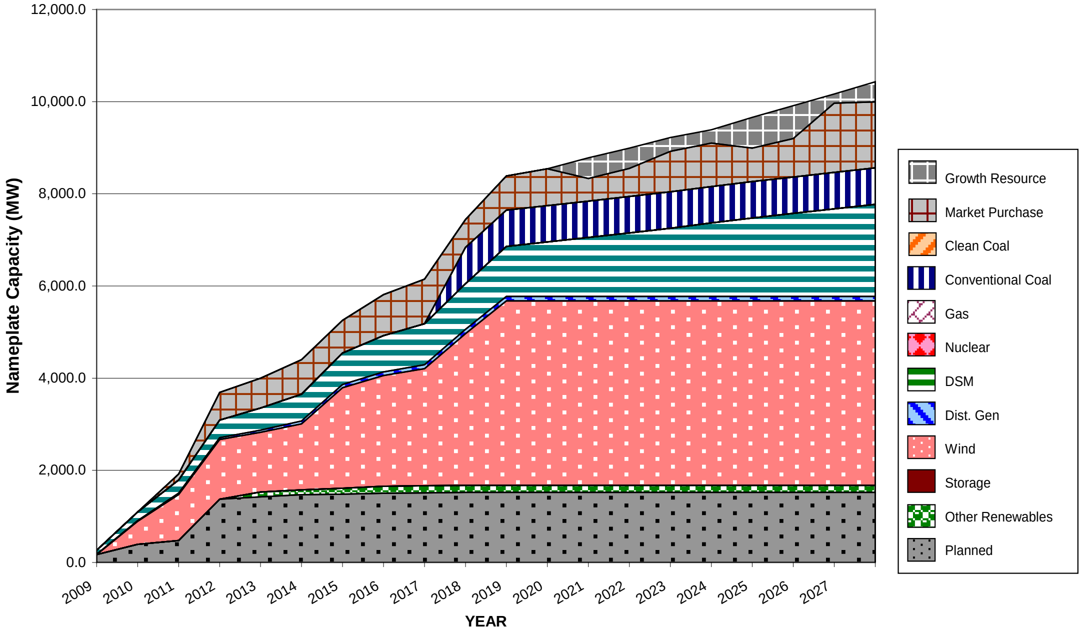
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 03

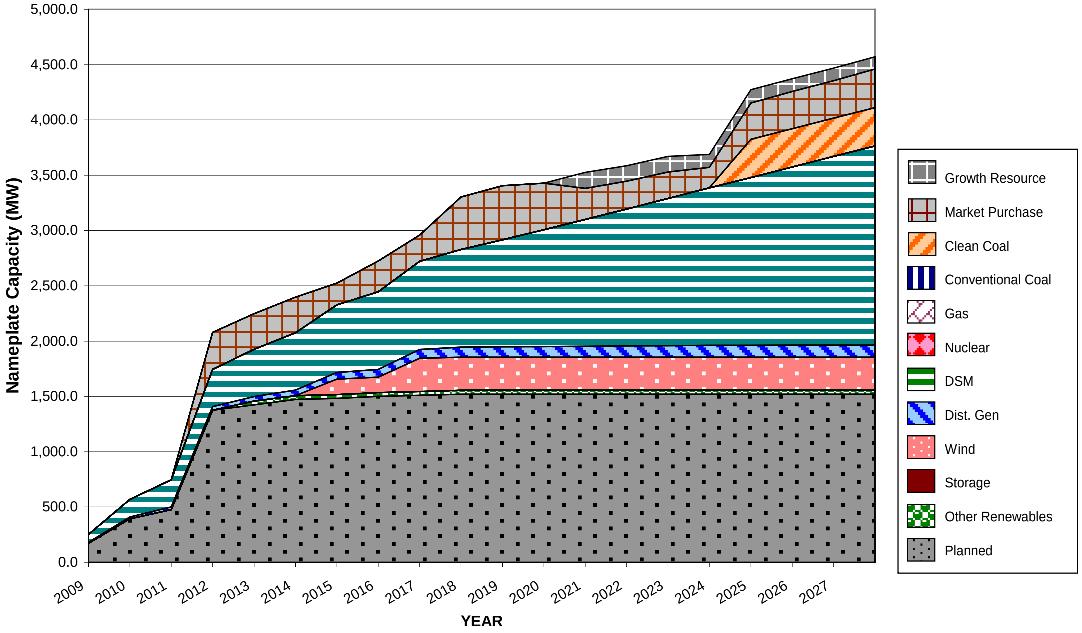
PVRR = $19,503



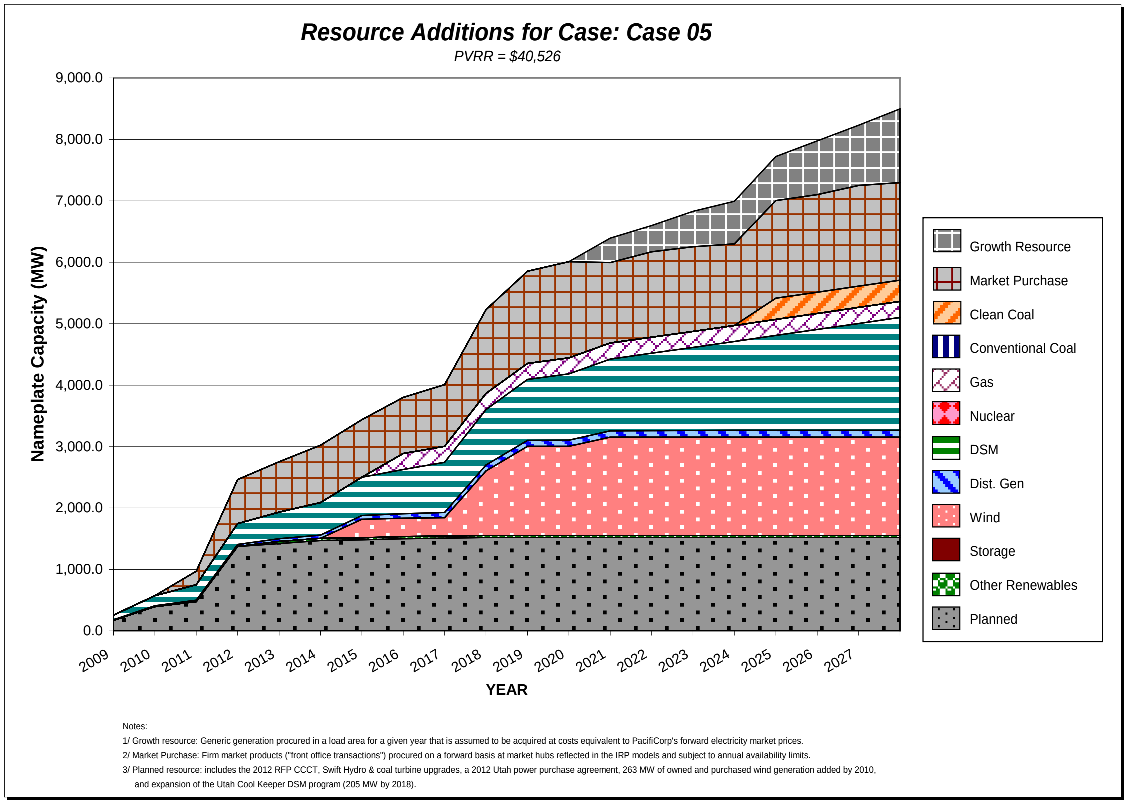
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 04

PVRR = $34,612



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).


Resource Additions for Case: Case 05

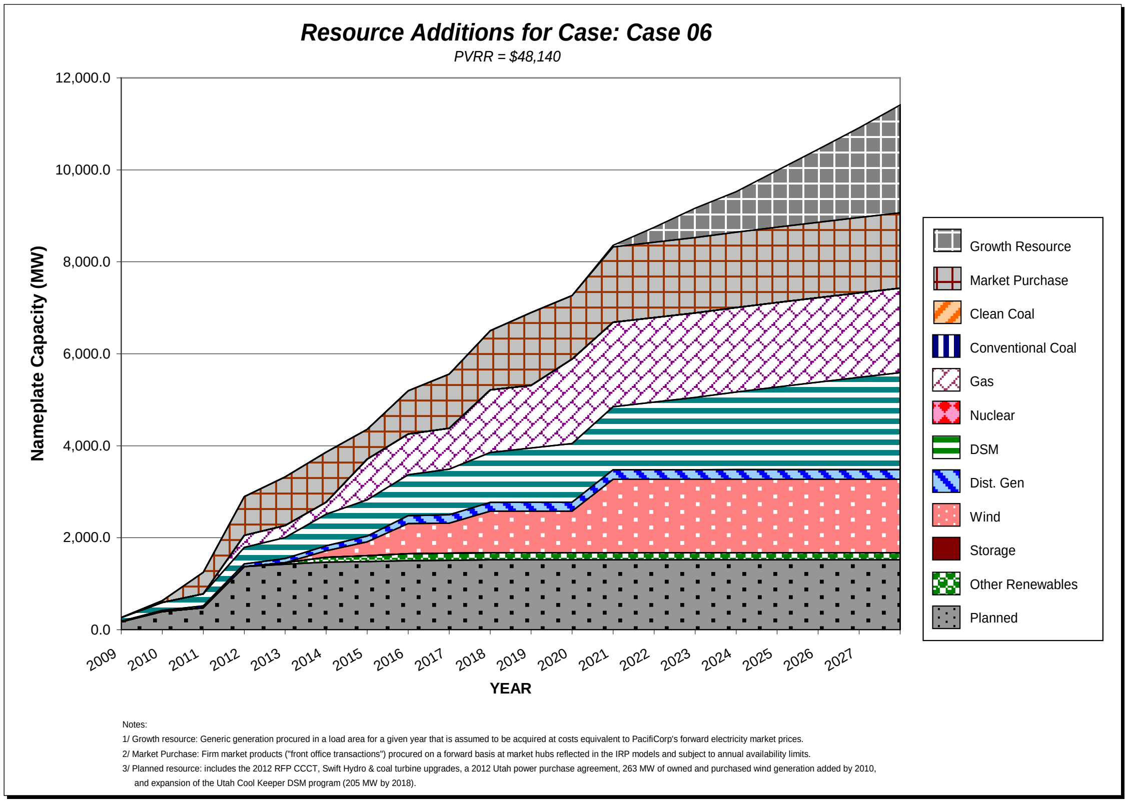
PVRR = $40,526

Notes:

1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).


Resource Additions for Case: Case 06

PVRR = $48,140

Notes:

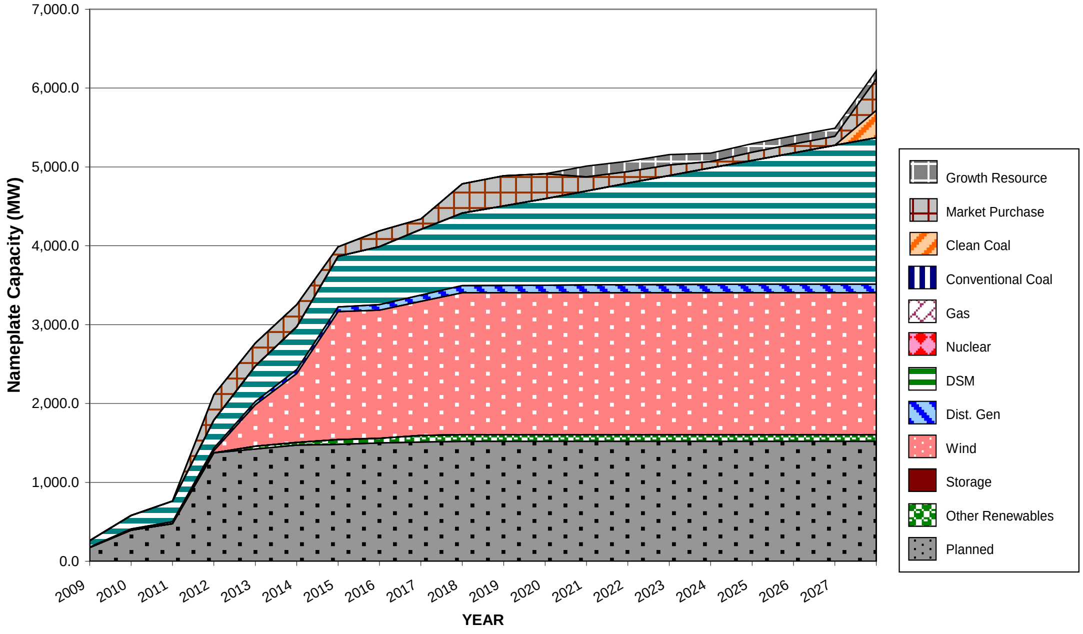
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 07

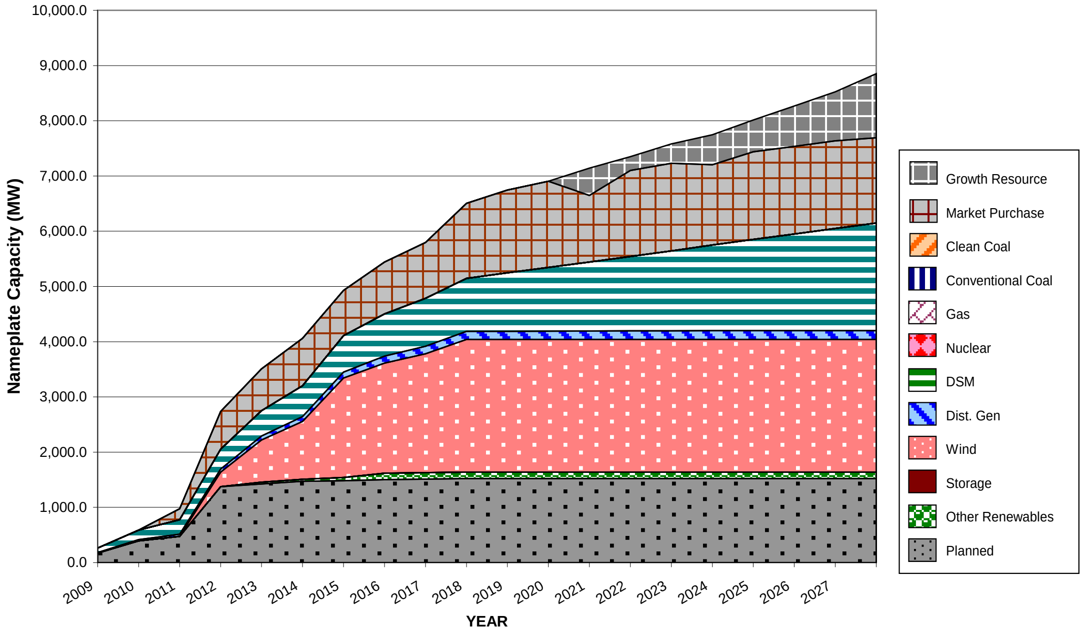
PVRR = $34,582



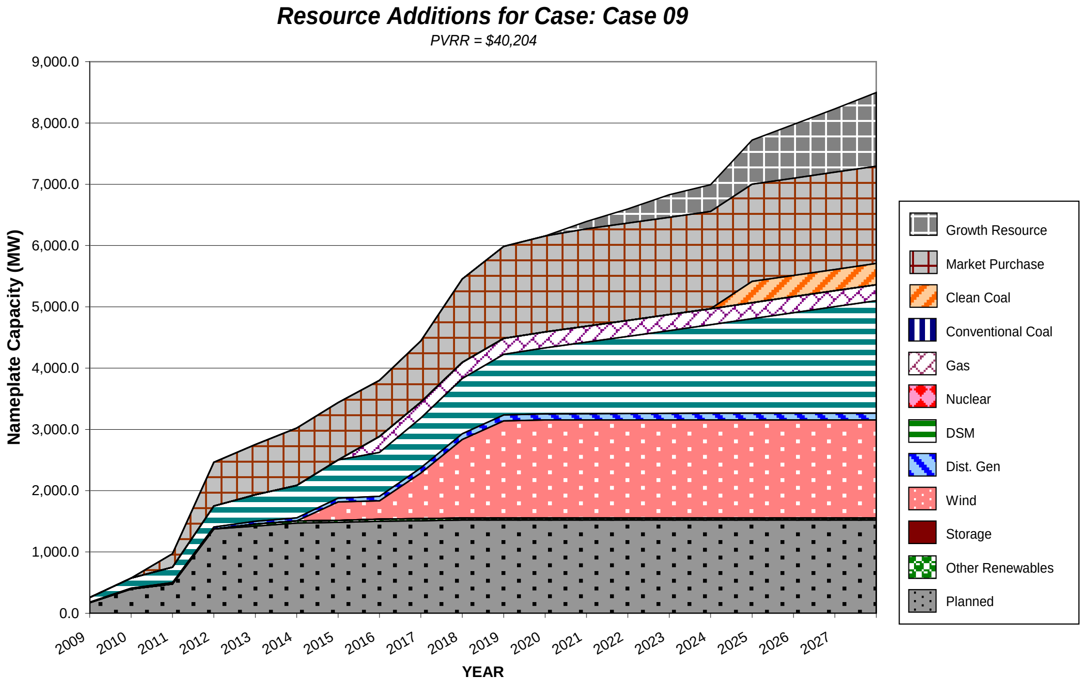
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 08

PVRR = $41,372



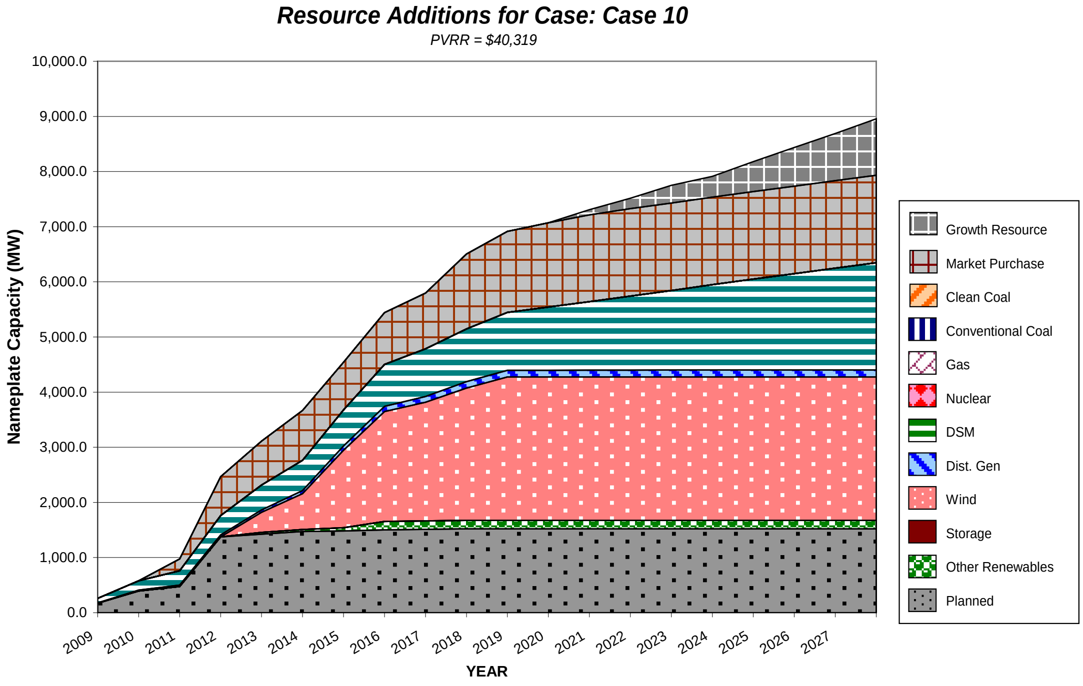
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 09

PVRR = $40,204

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010,
and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



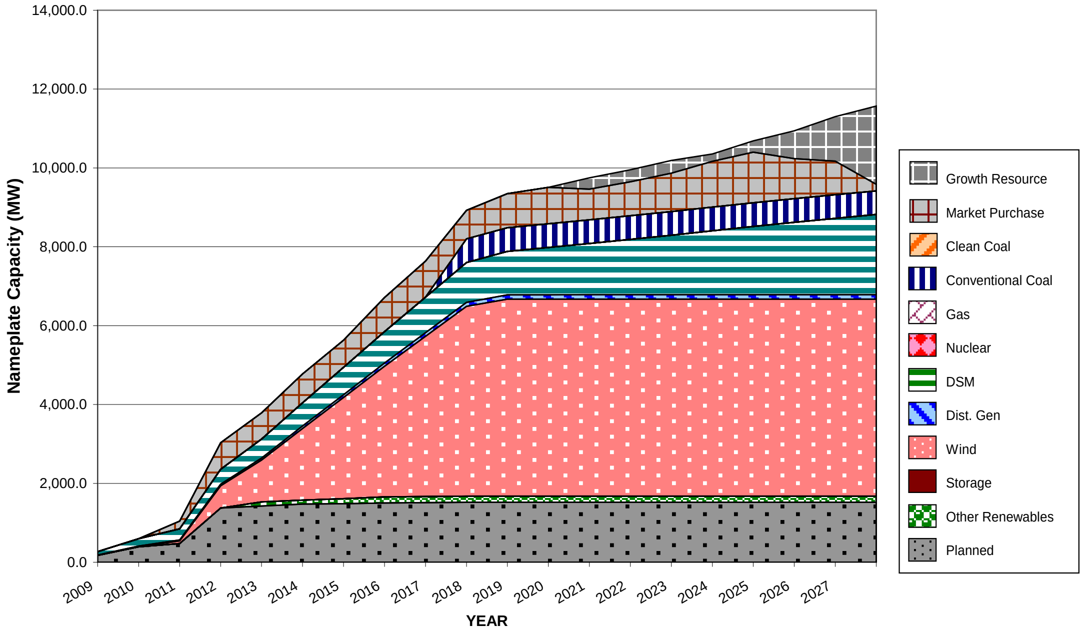
Resource Additions for Case: Case 10

PVRR = $40,319

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010,
and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 11

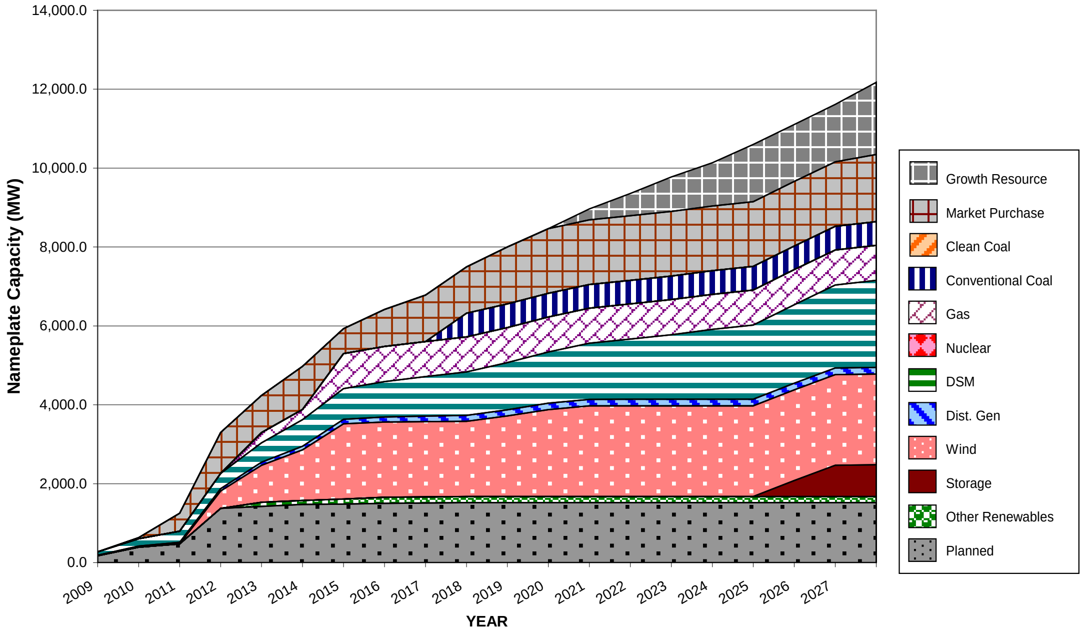
PVRR = $40,559



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 12

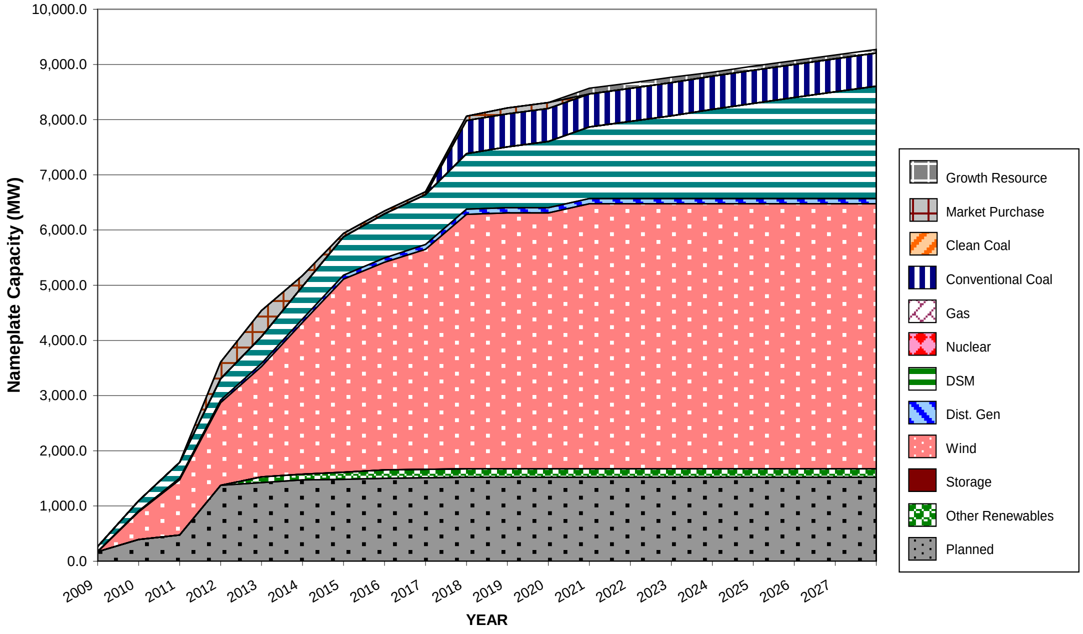
PVRR = $50,146



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 13

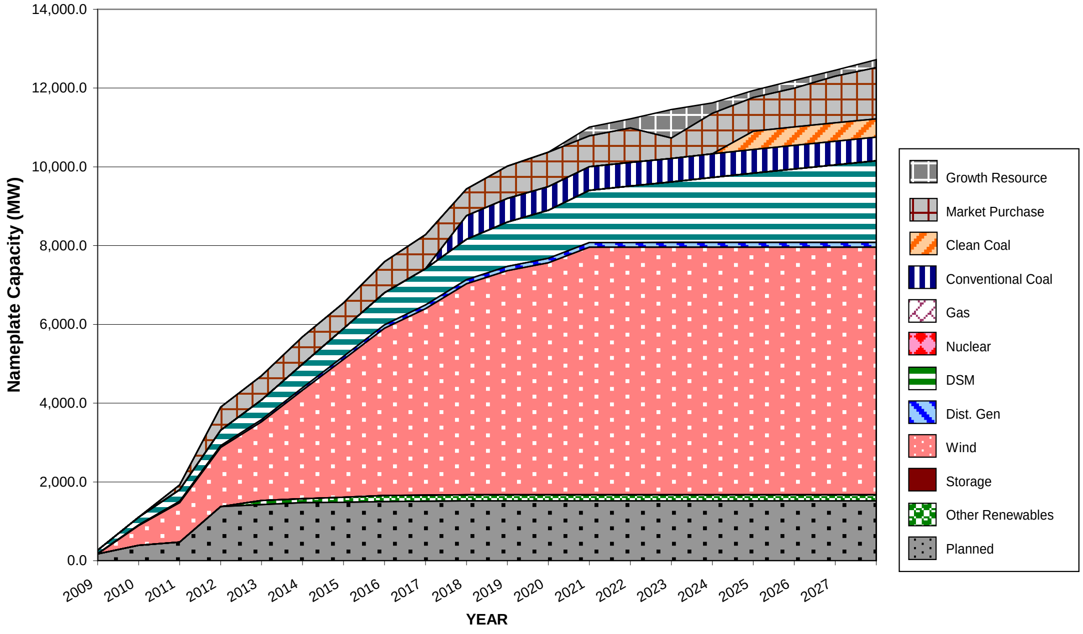
PVRR = $31,076



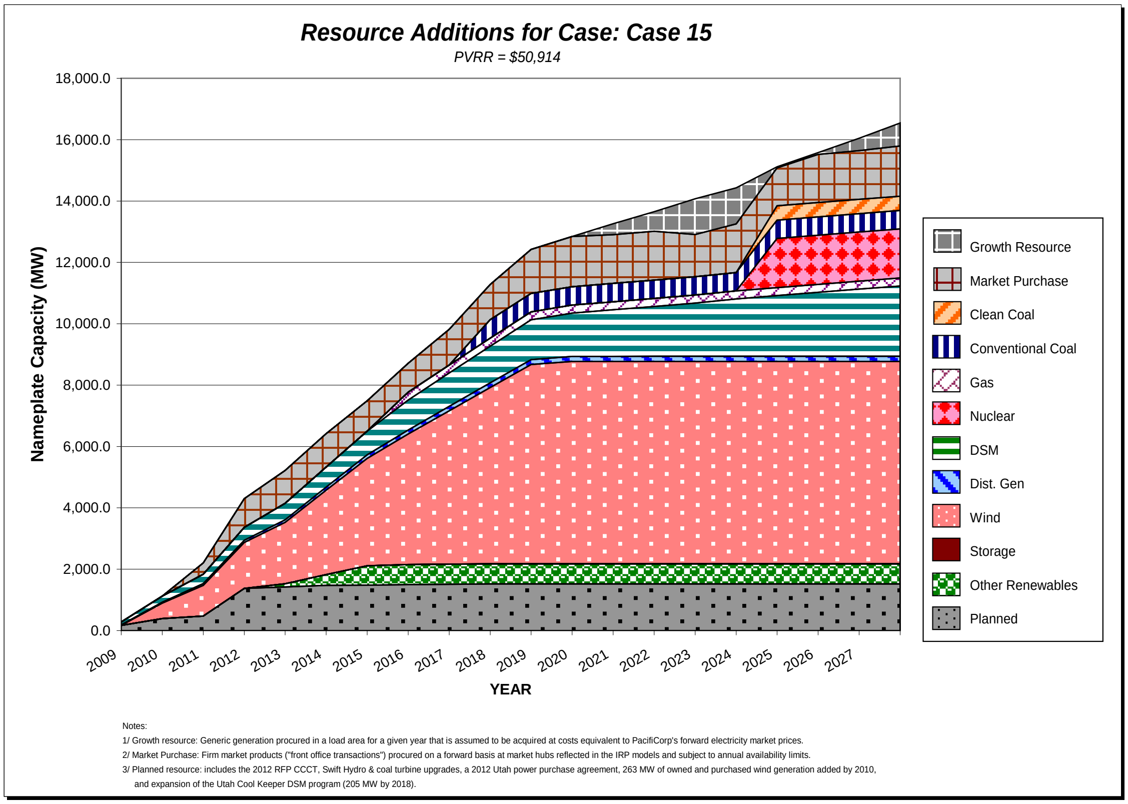
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 14

PVRR = $39,949



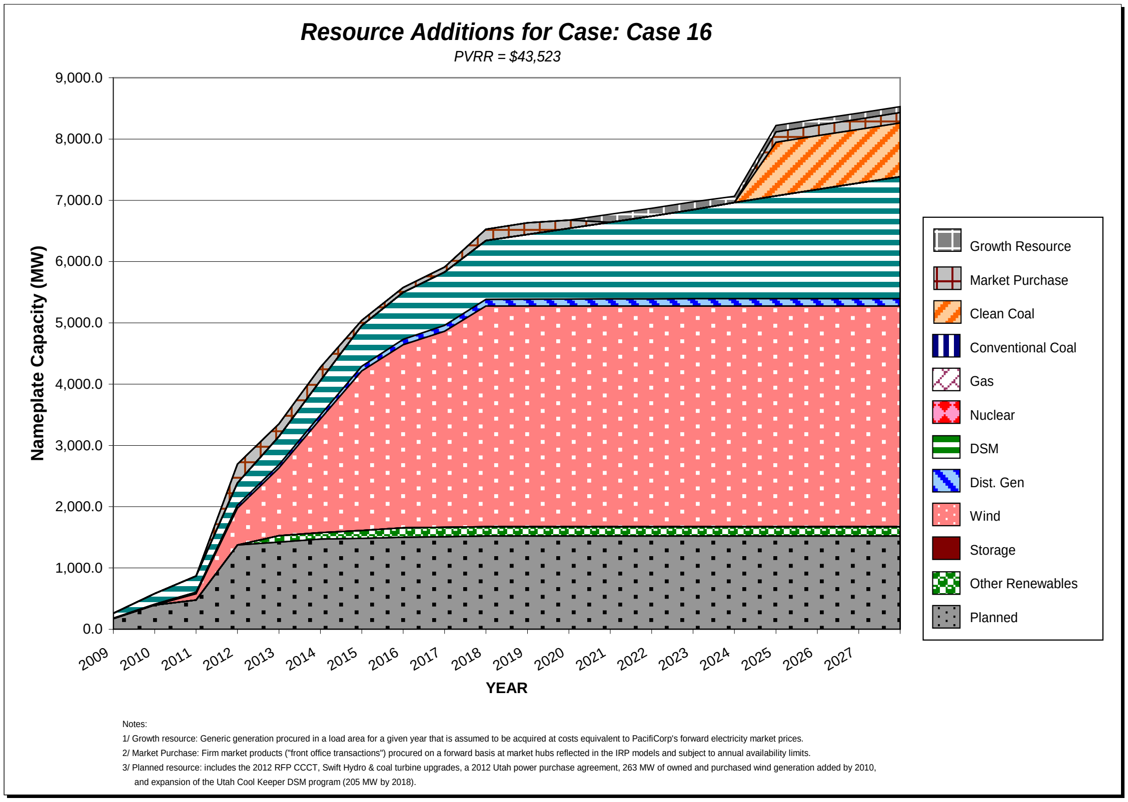
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 15

PVRR = $50,914

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



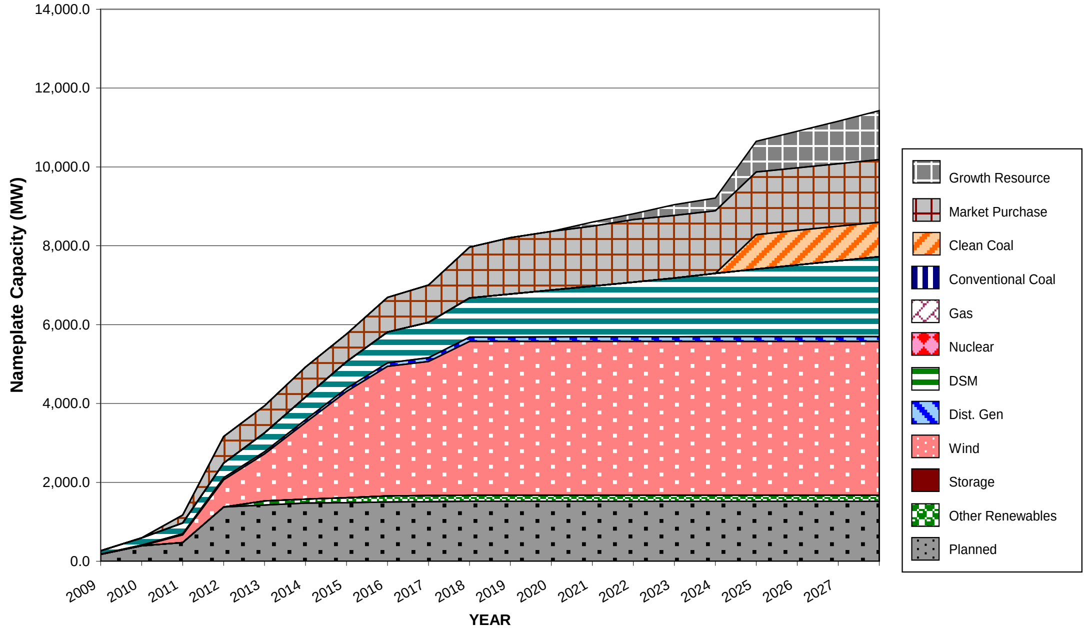
Resource Additions for Case: Case 16

PVRR = $43,523

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 17

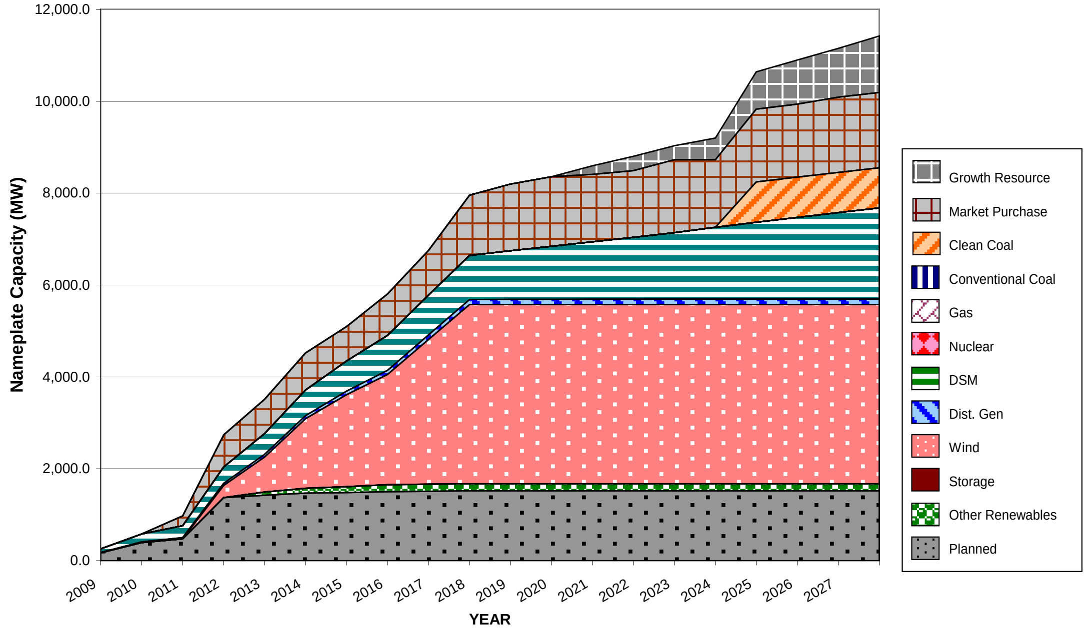
PVRR = $51,207



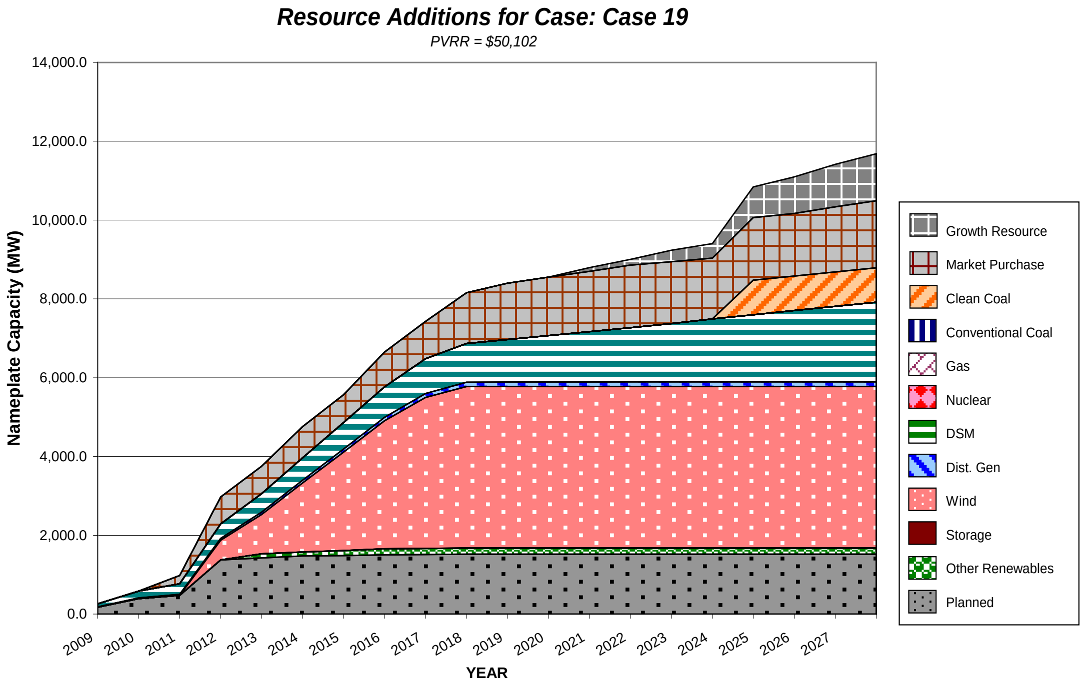
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 18

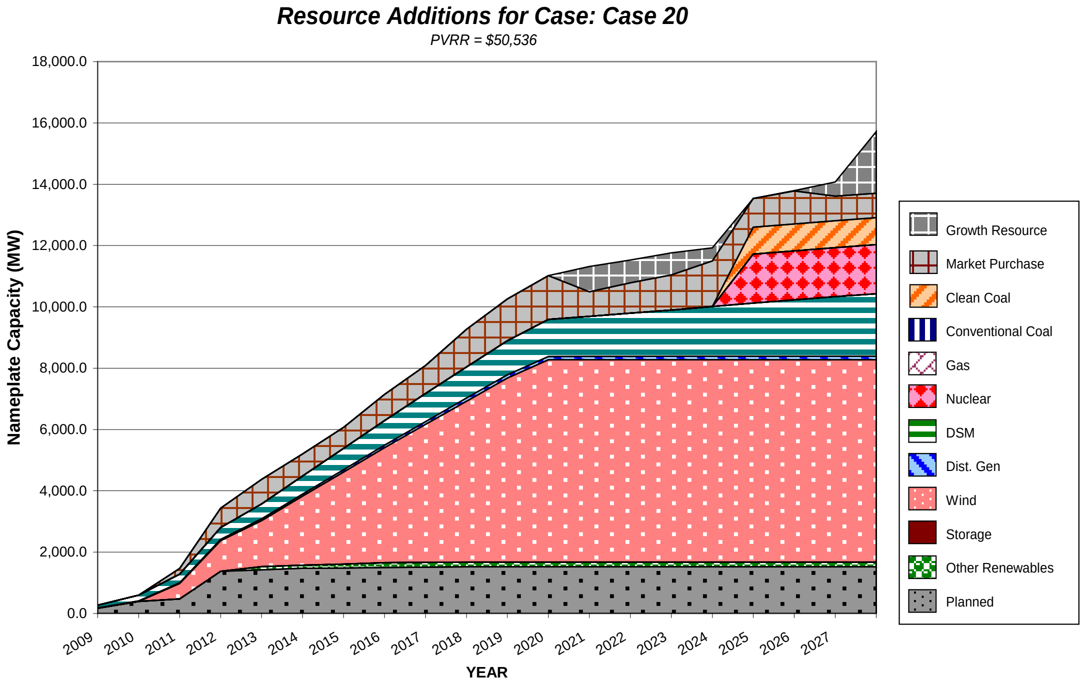
PVRR = $49,745



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



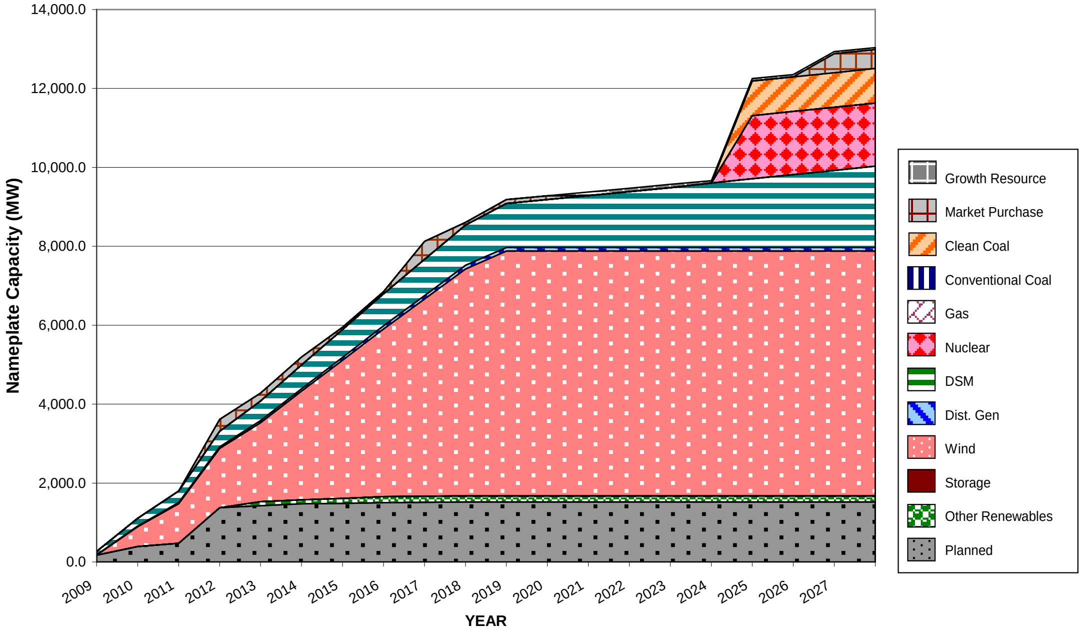
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 21

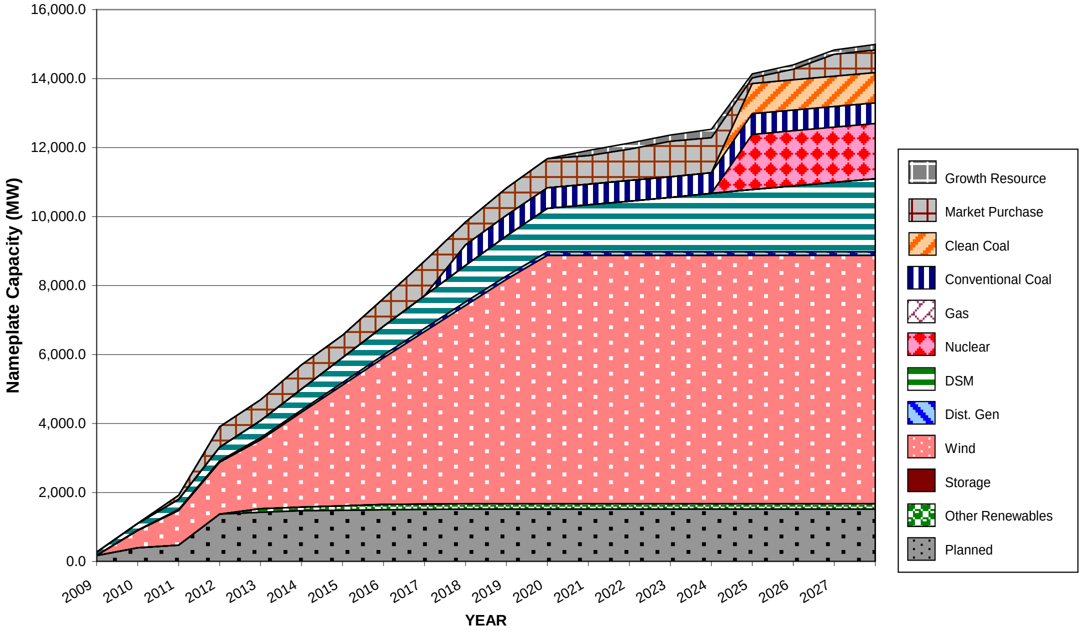
PVRR = $40,517



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 22

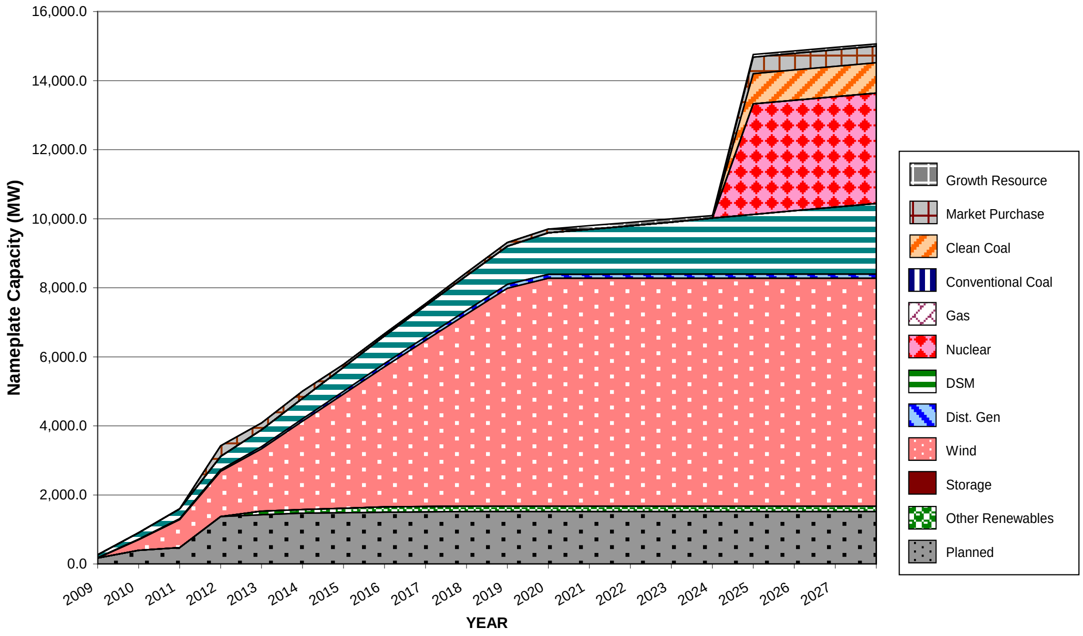
PVRR = $49,983



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 23

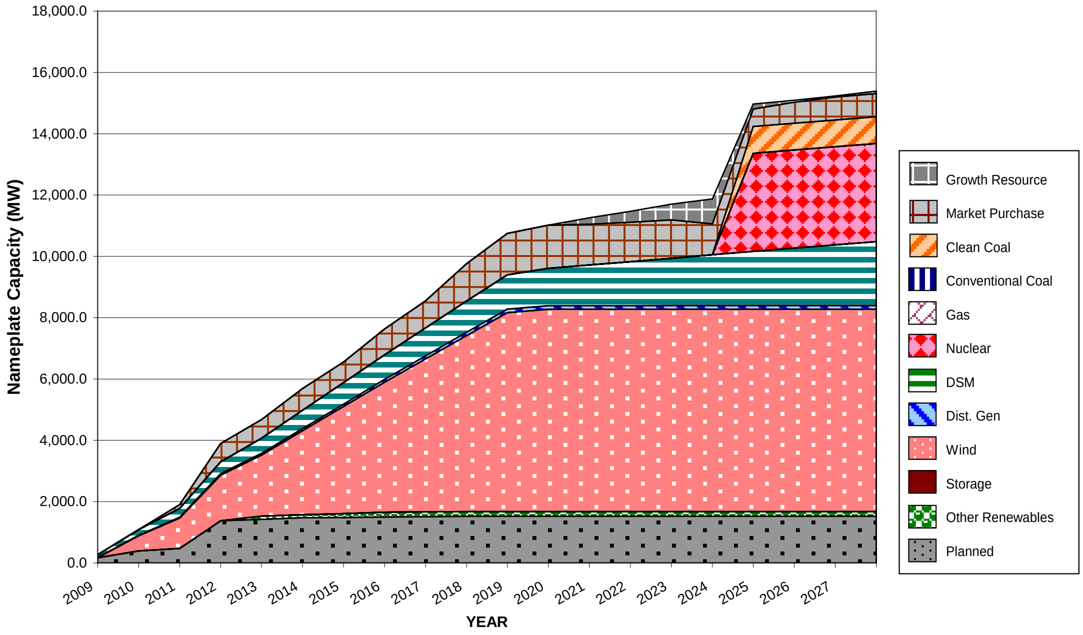
PVRR = $51,692



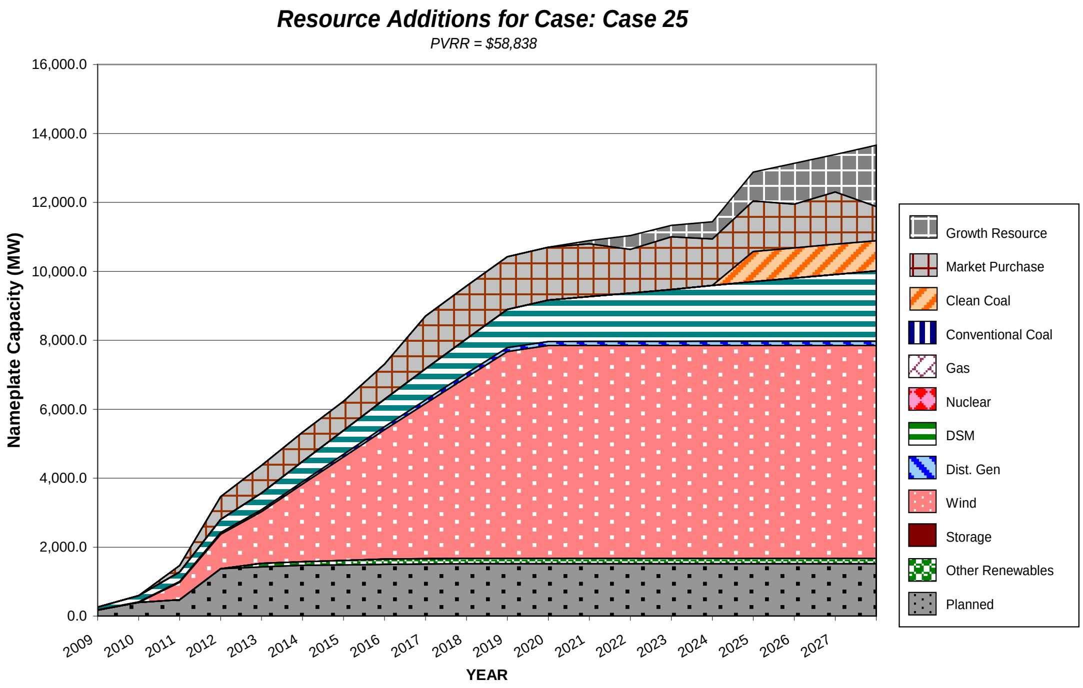
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 24

PVRR = $60,693

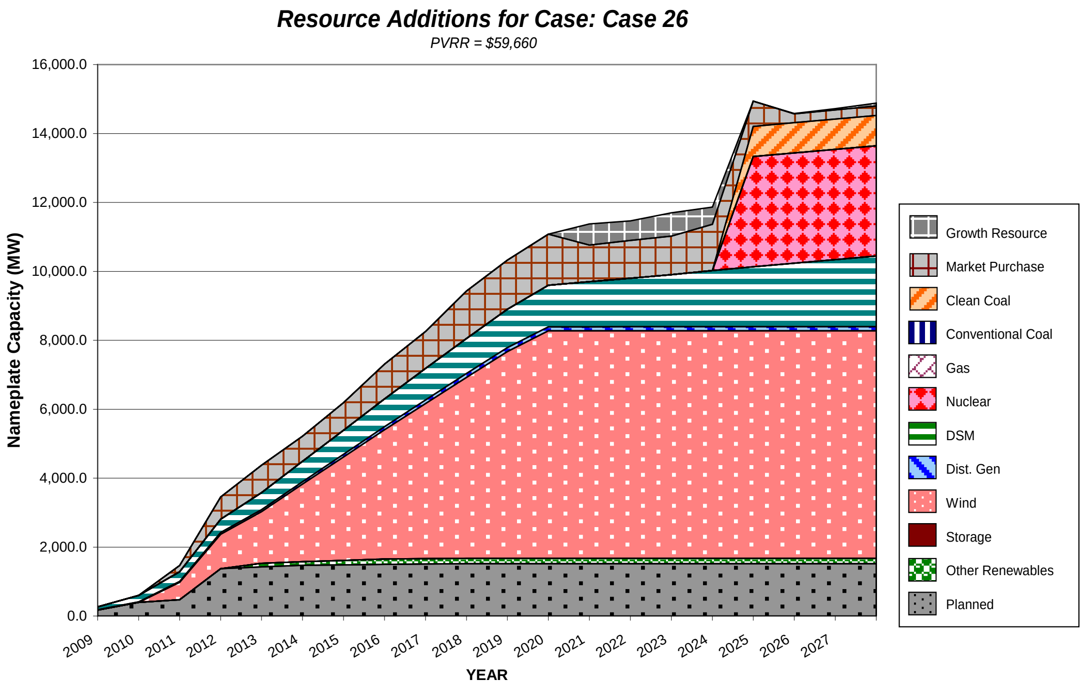


Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).


Resource Additions for Case: Case 25

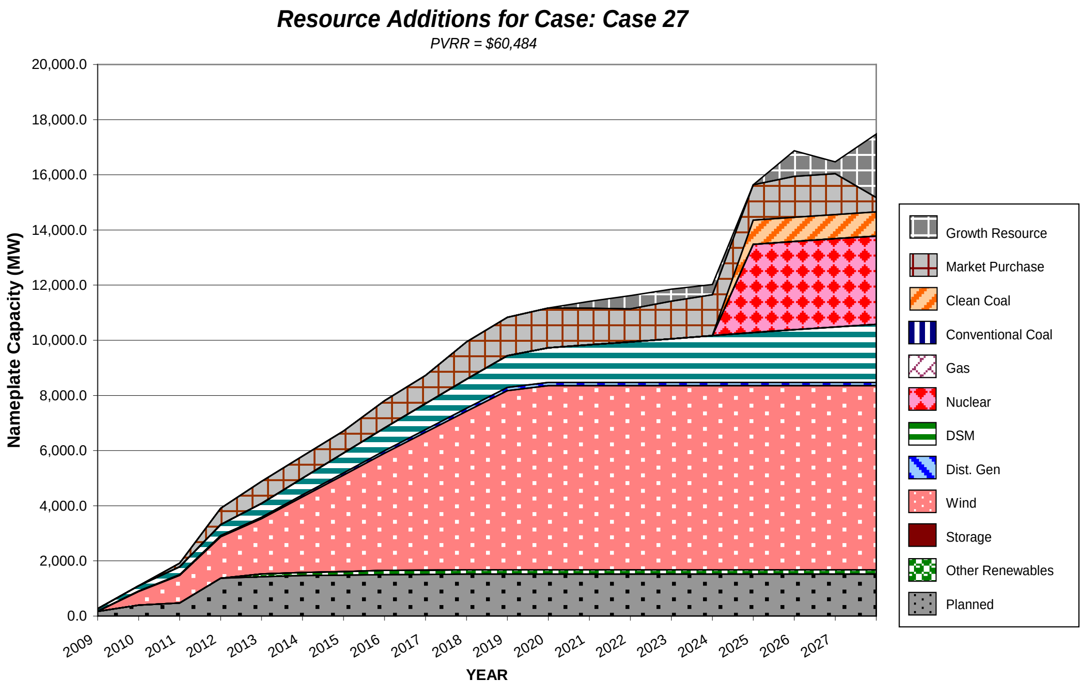
PVRR = $58,838

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

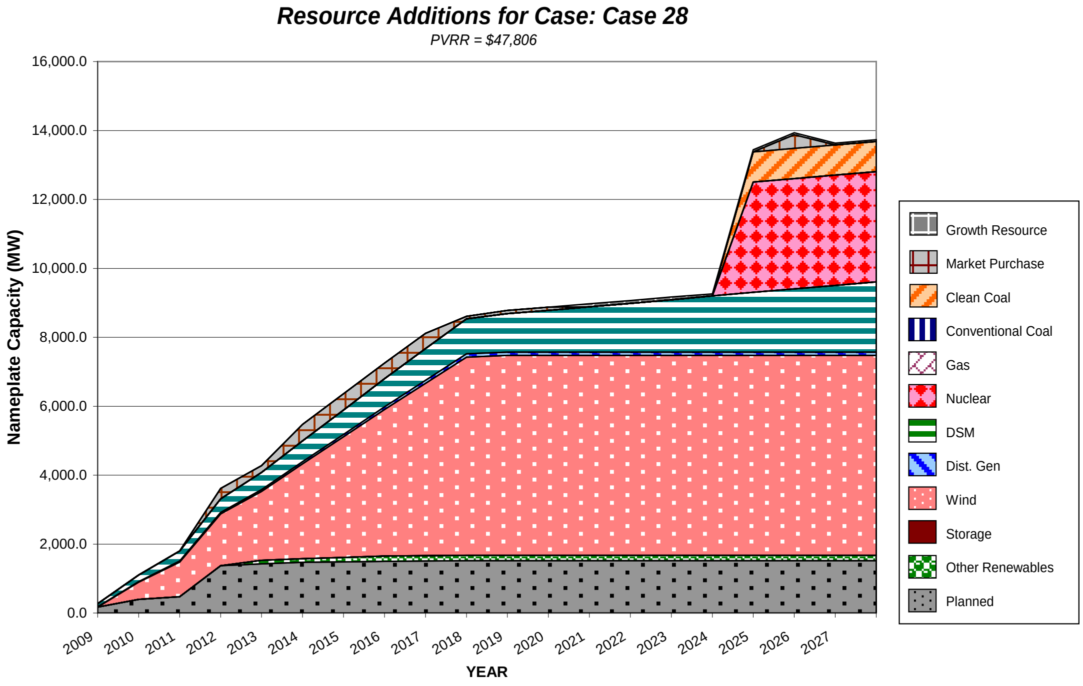

Resource Additions for Case: Case 26

PVRR = $59,660

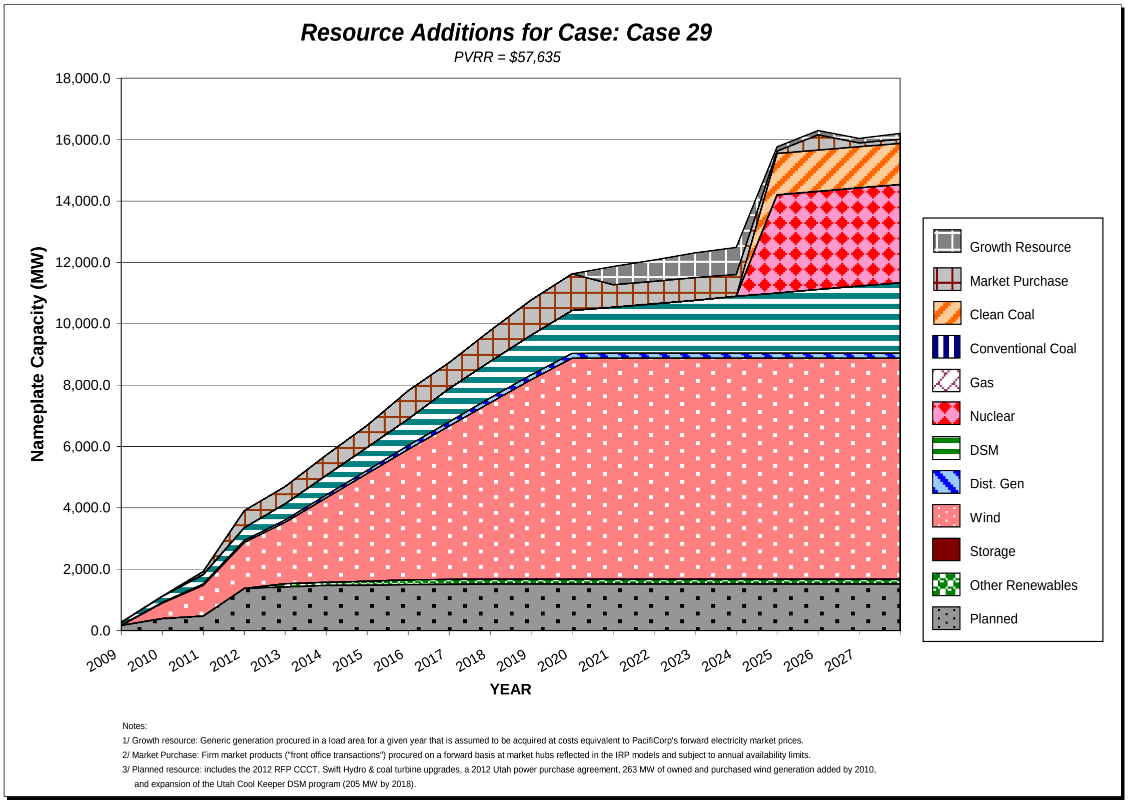
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



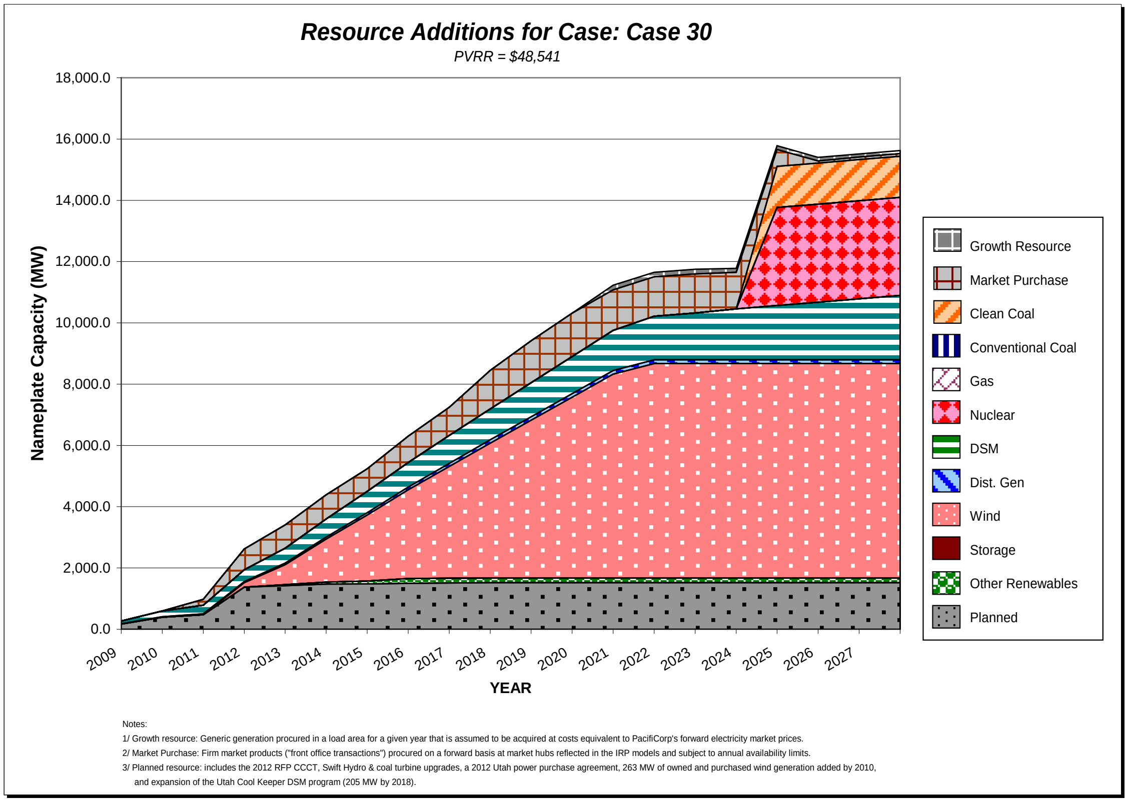
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 29

PVRR = $57,635

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



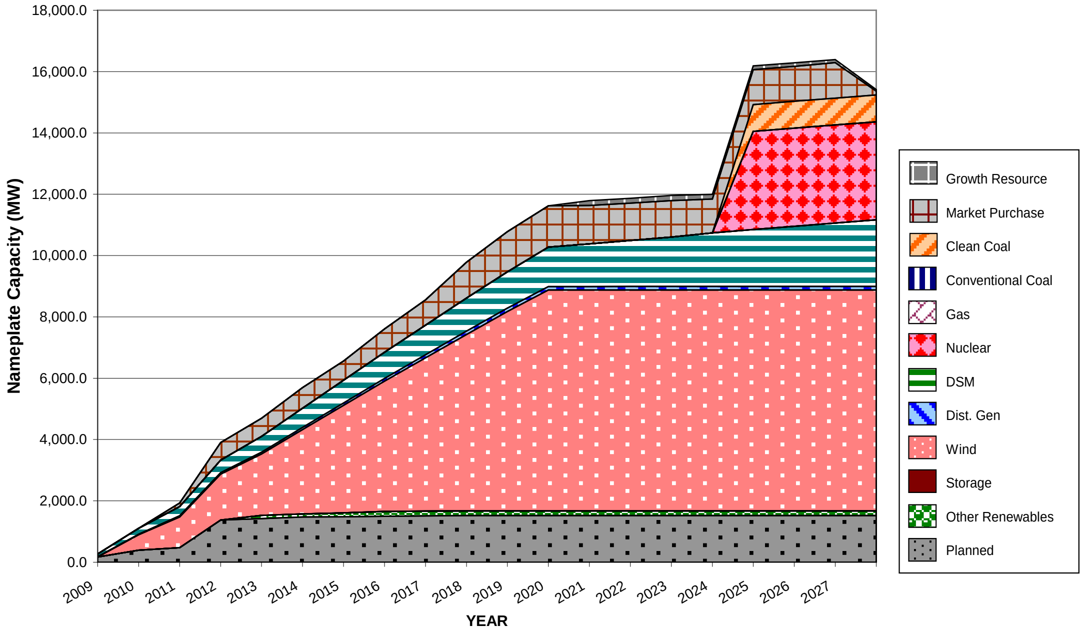
Resource Additions for Case: Case 30

PVRR = $48,541

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 31

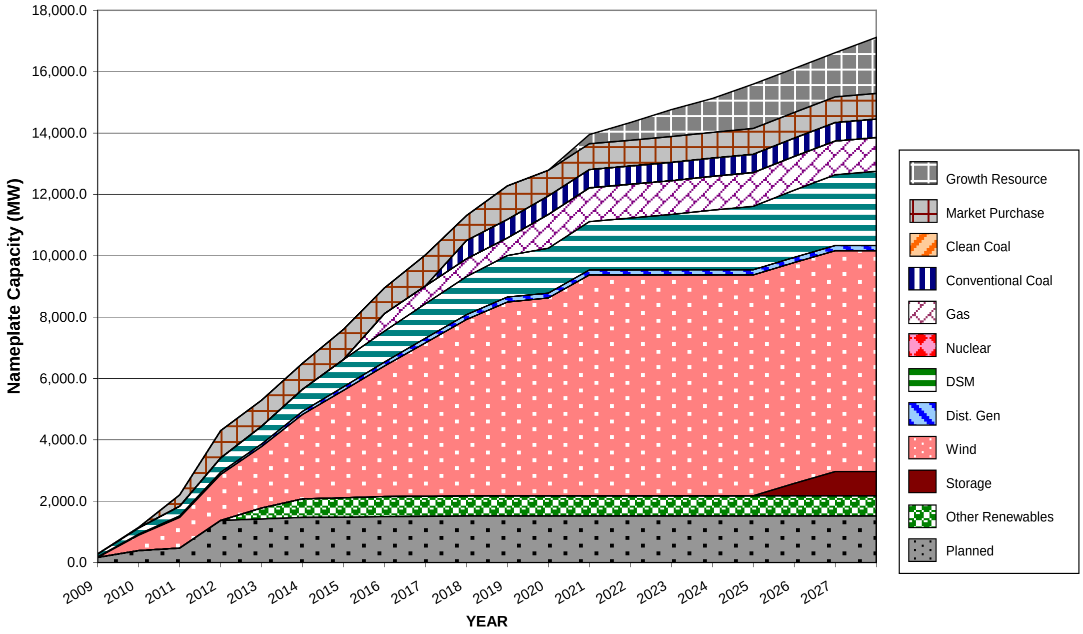
PVRR = $47,552



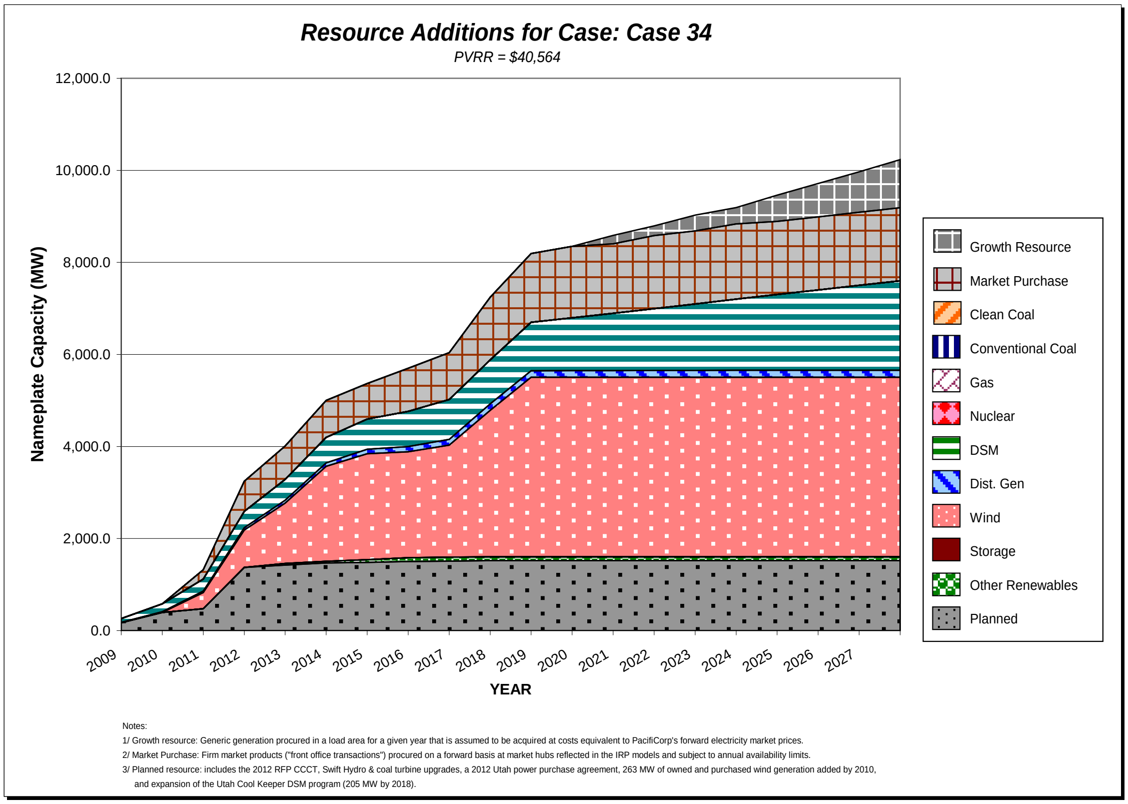
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 33

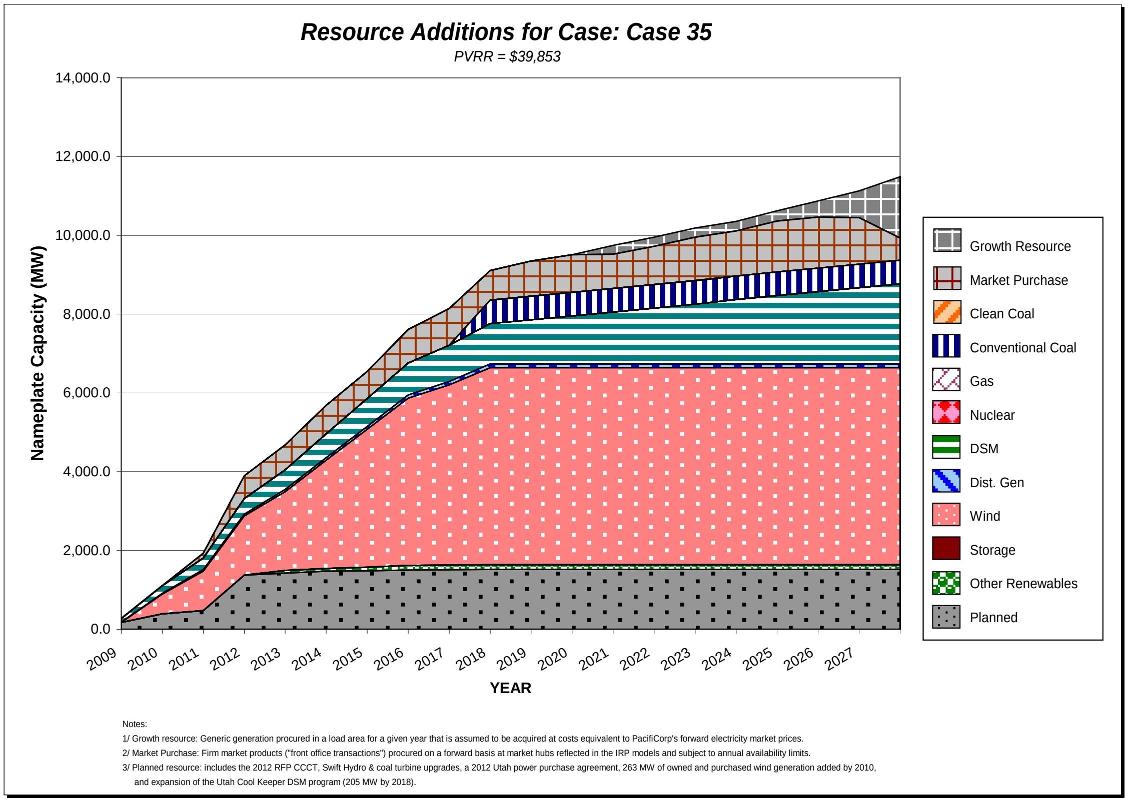
PVRR = $69,949



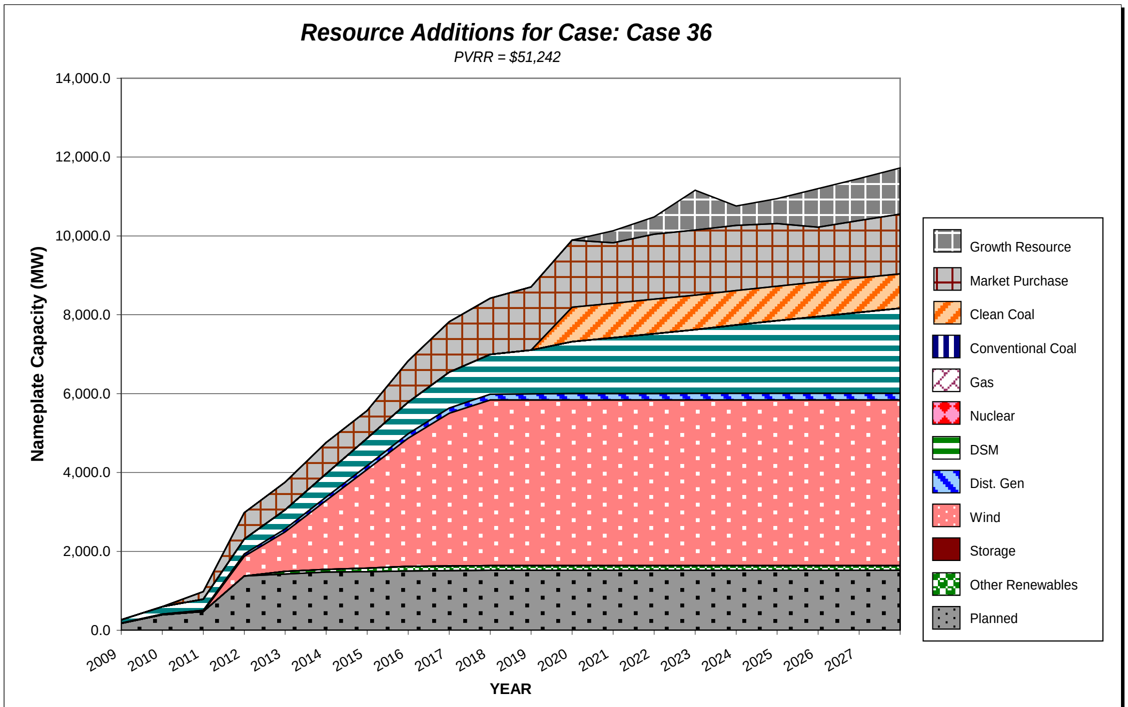
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



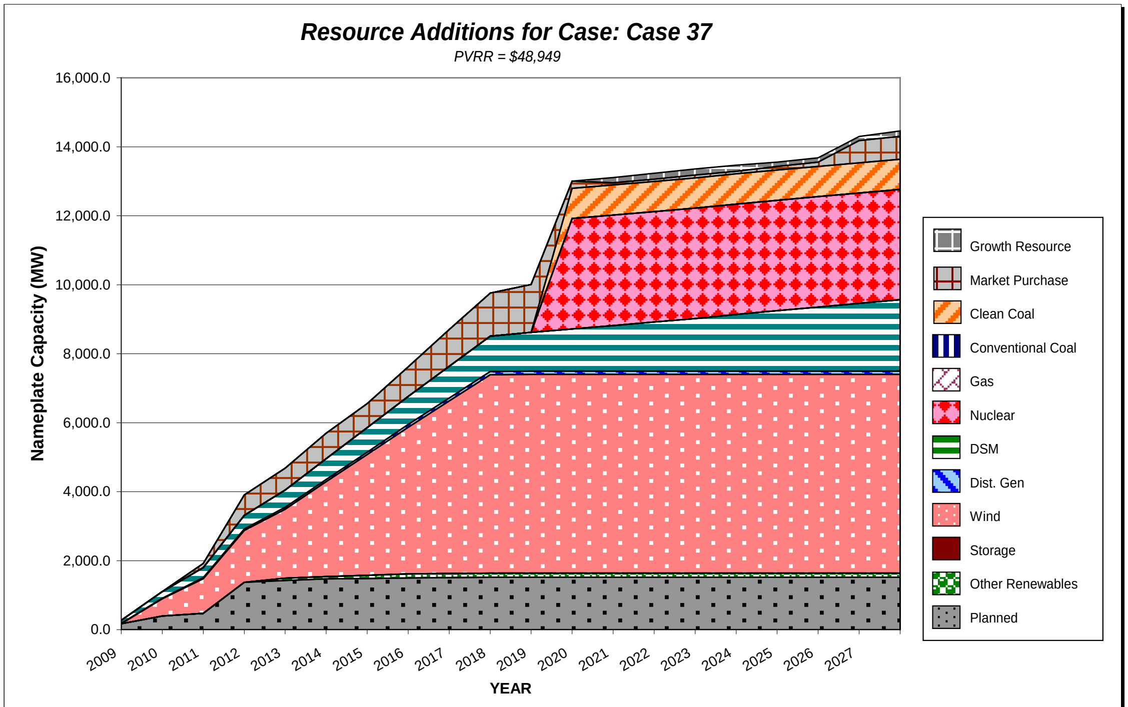
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



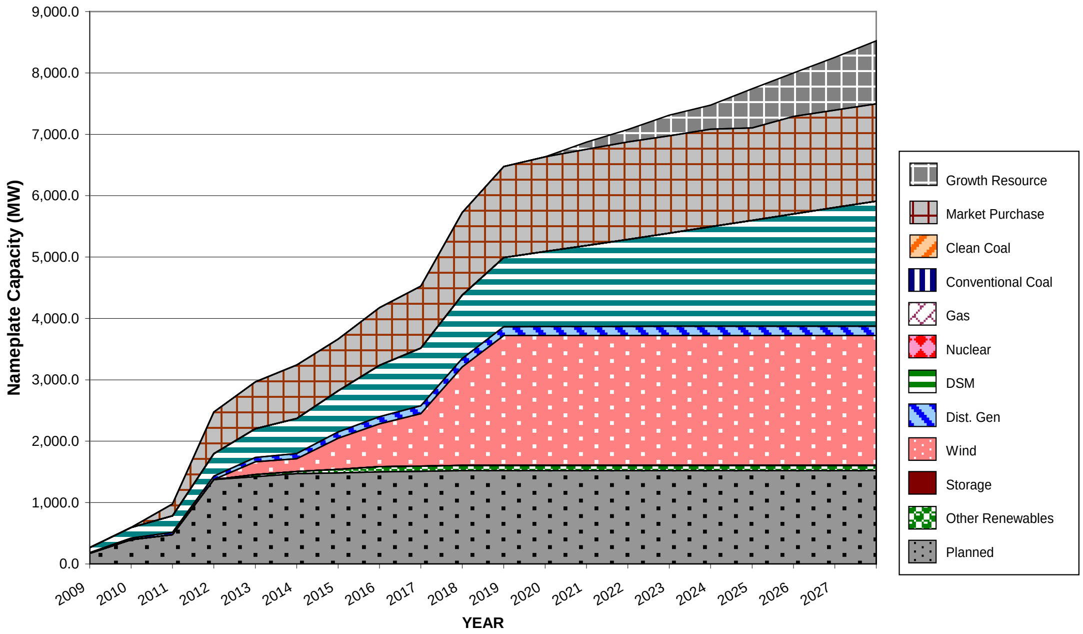
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



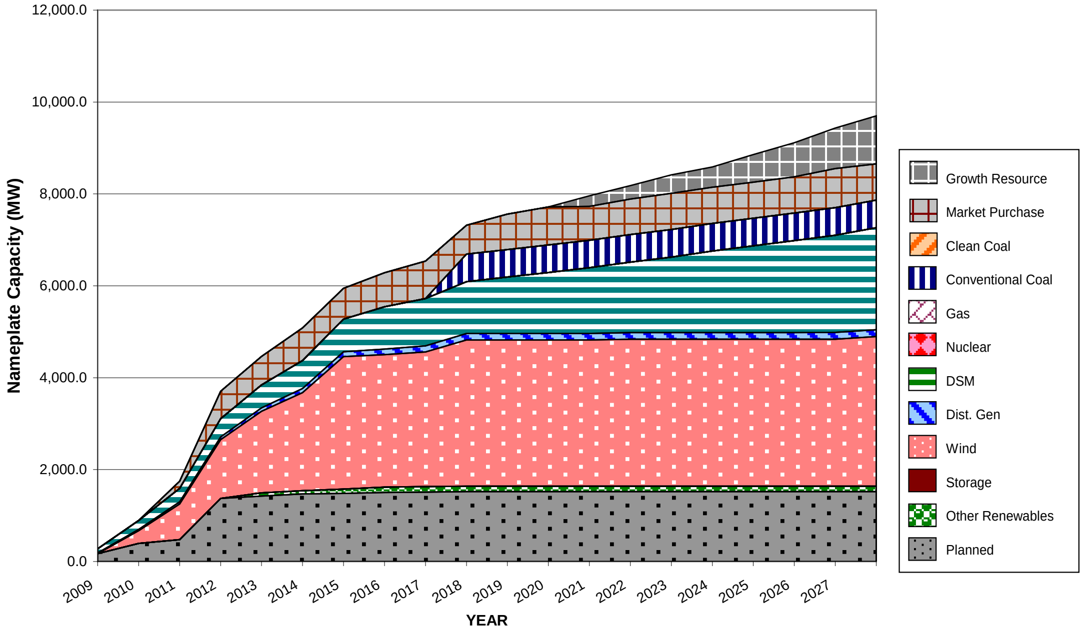
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 38

PVRR = $41,974

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



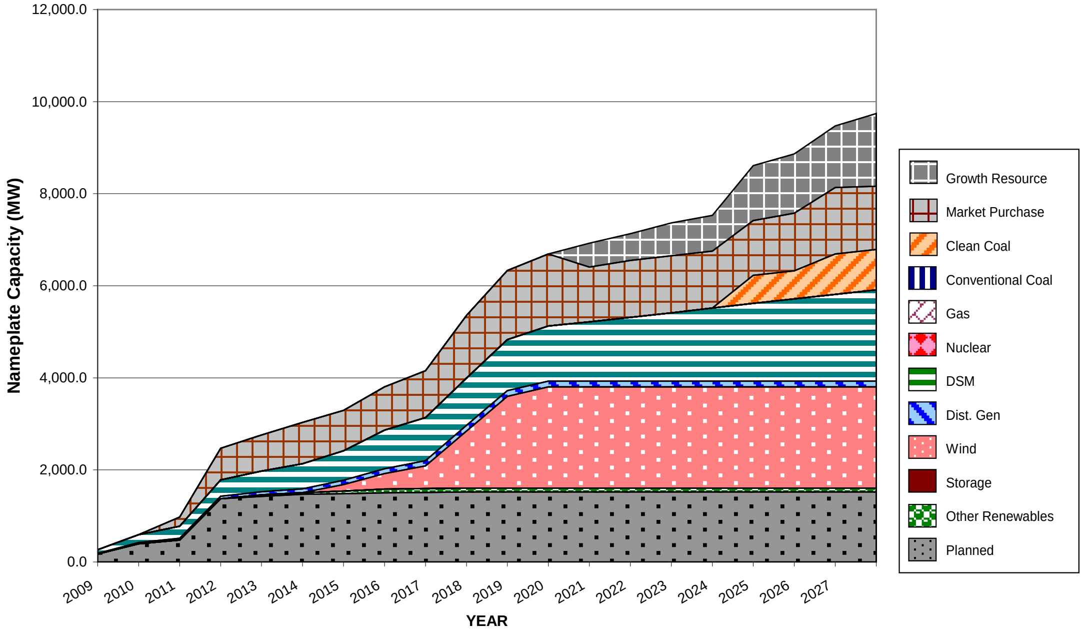
Resource Additions for Case: Case 39

PVRR = $34,791

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 40

PVRR = $24,761



Notes:

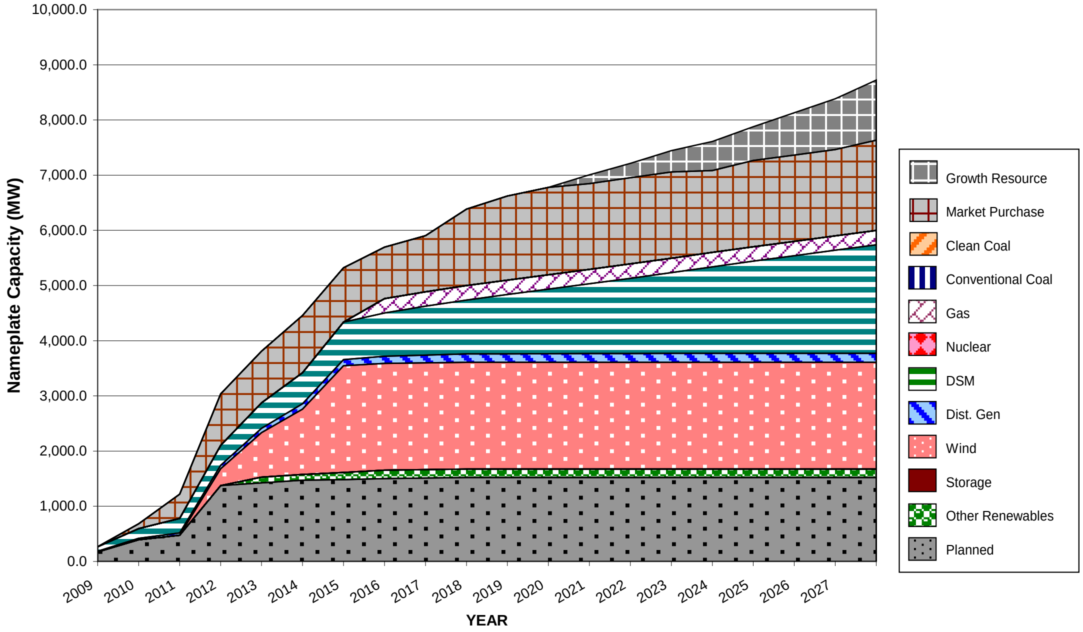
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 41

PVRR = $41,542



Notes:

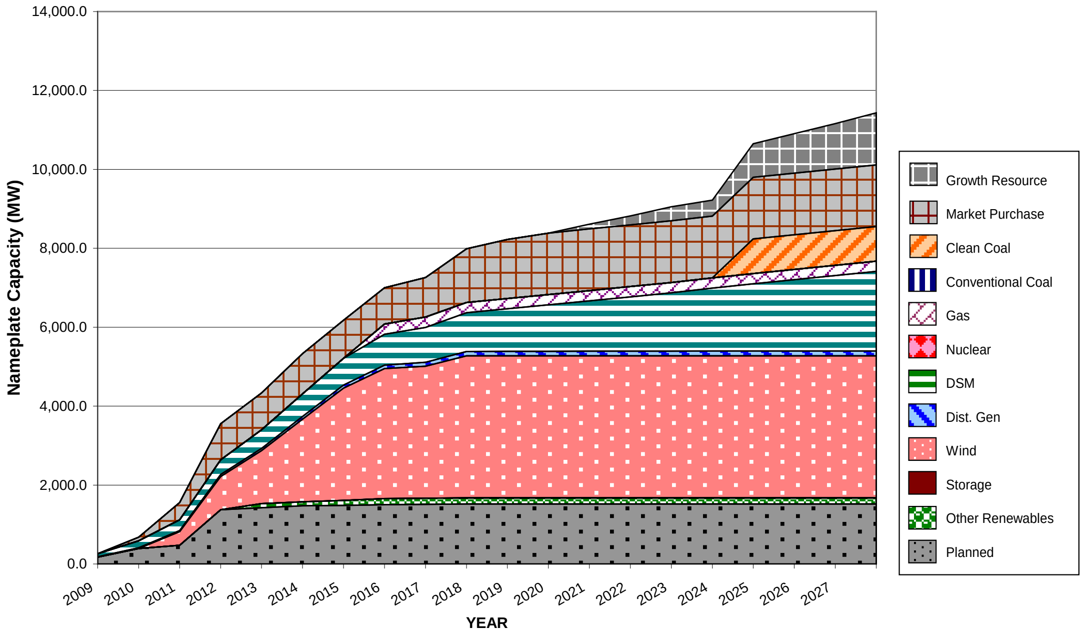
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 42

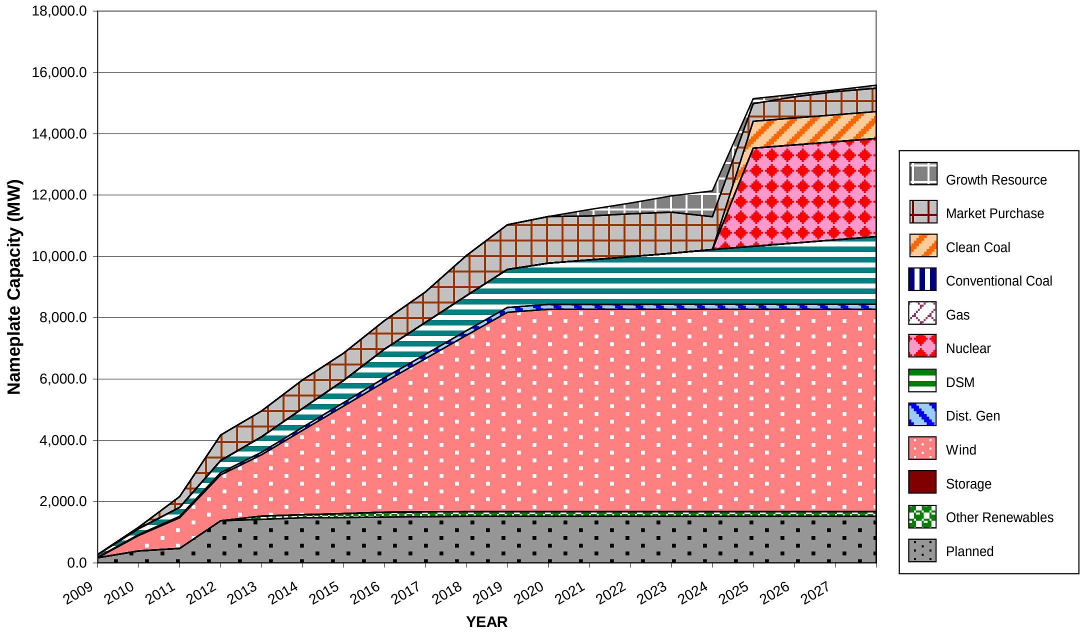
PVRR = $51,420



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 43

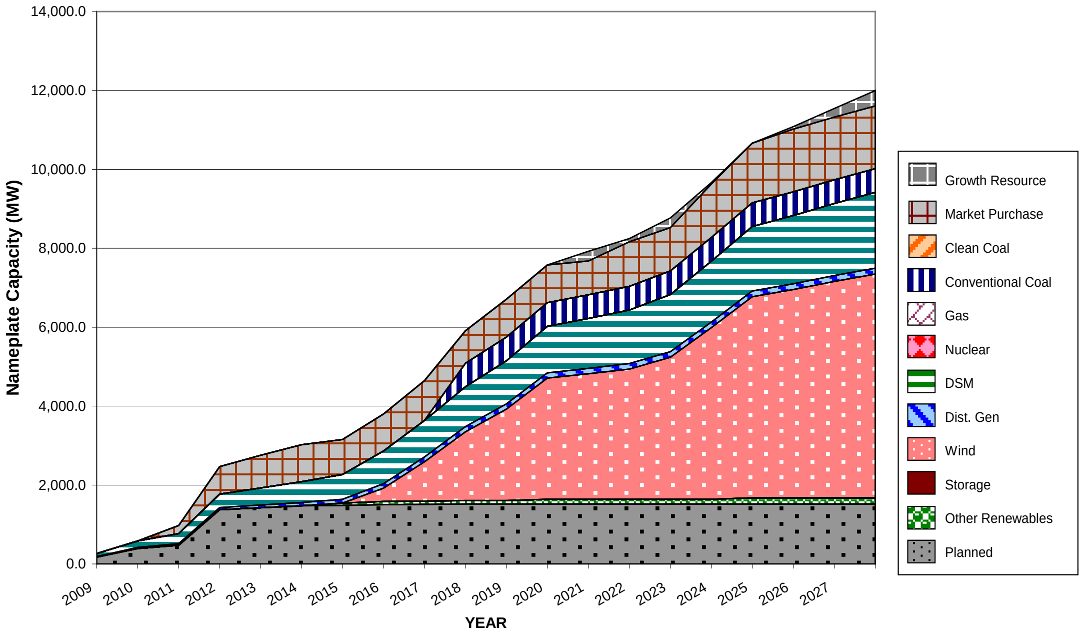
PVRR = $60,905



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 44

PVRR = $21,249



Notes:

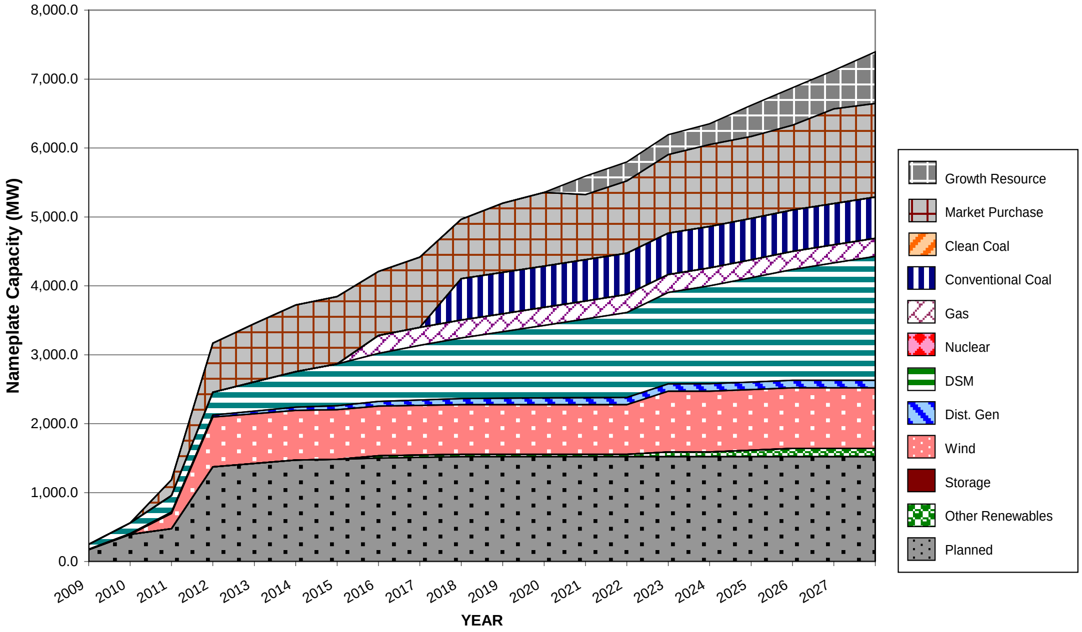
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 45

PVRR = $20,875



Notes:

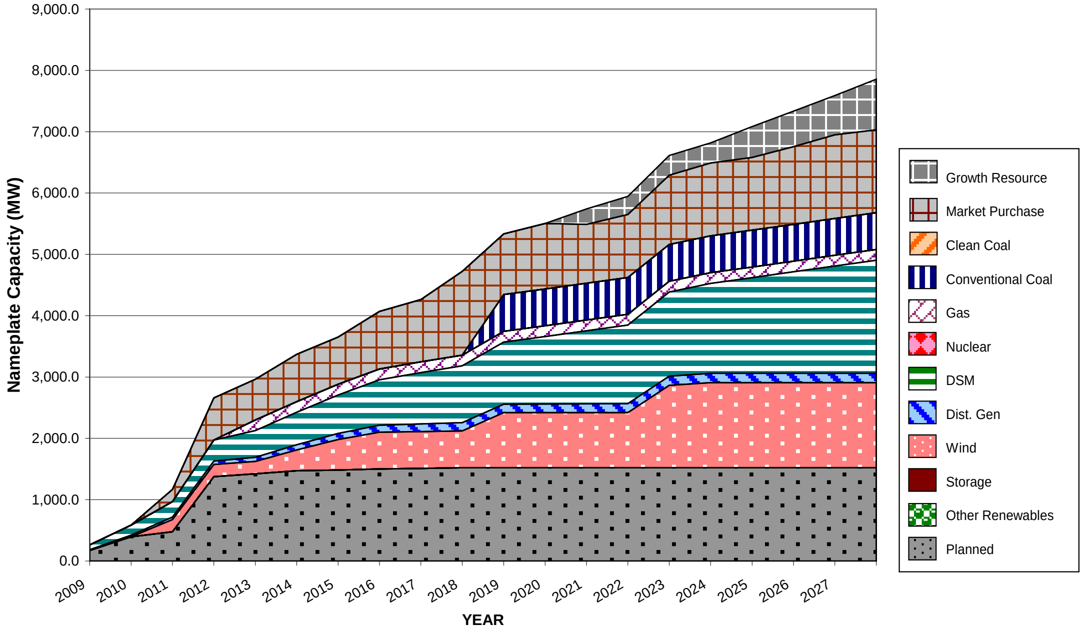
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 46

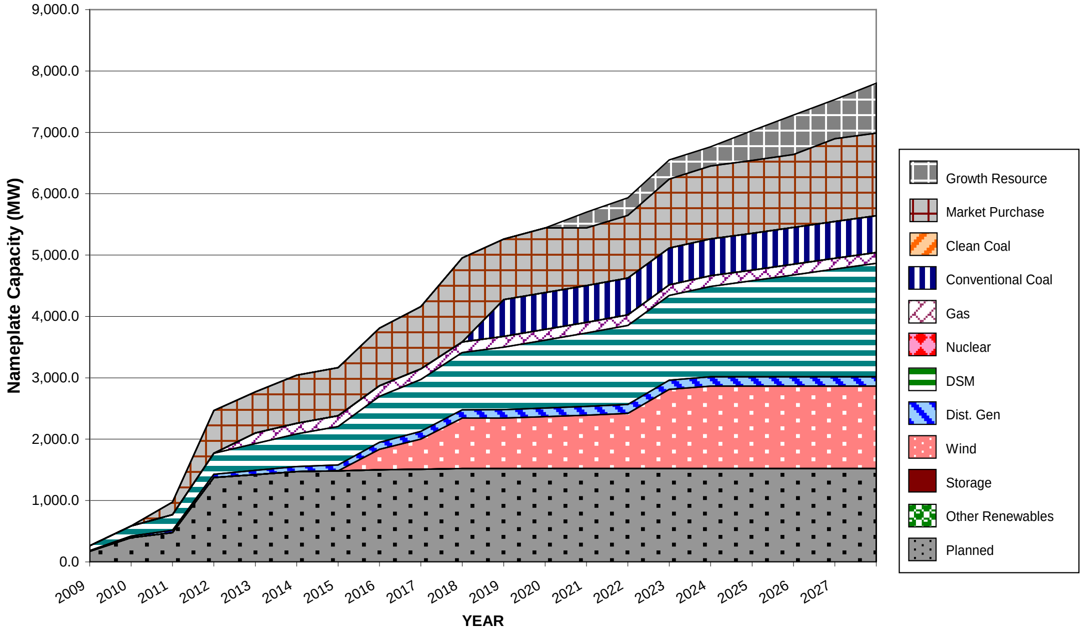
PVRR = $21,532



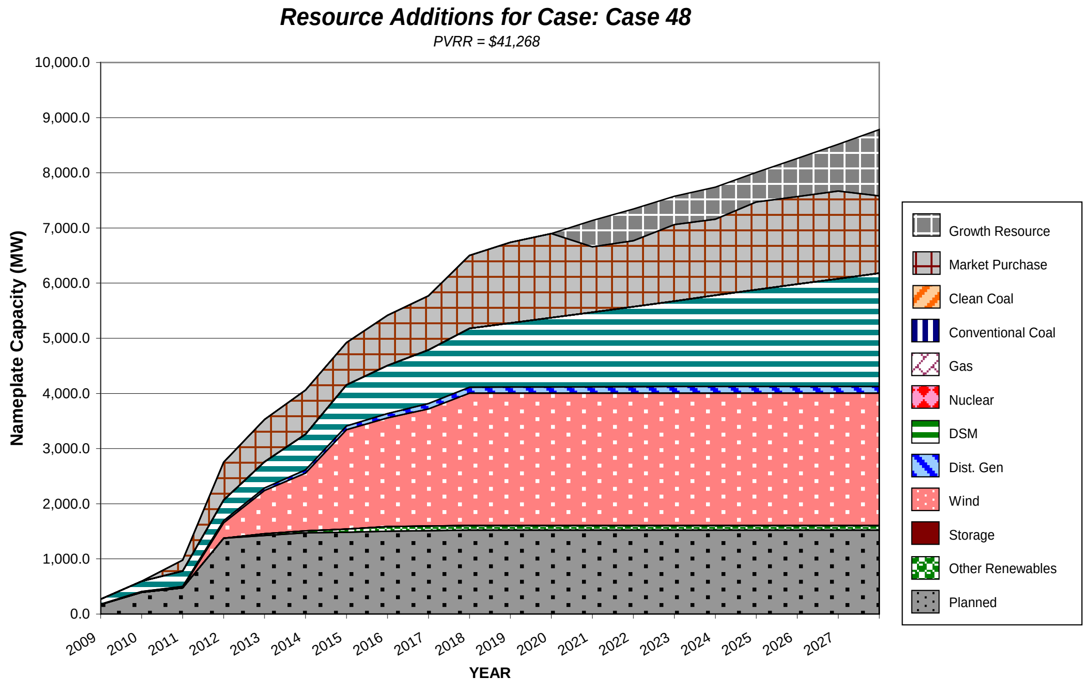
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 47

PVRR = $20,863



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:

1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

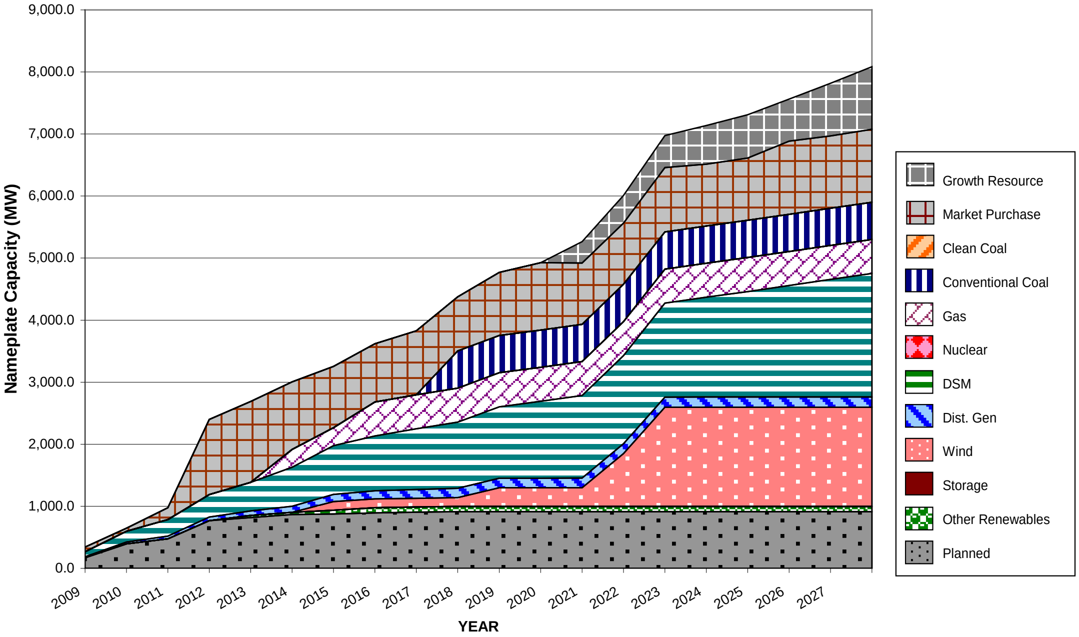
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Area Charts: "B-Series" – Portfolio Capacity Additions by Resource Type

Resource Additions for Case: Case 02b

PVRR = $22,040



Notes:

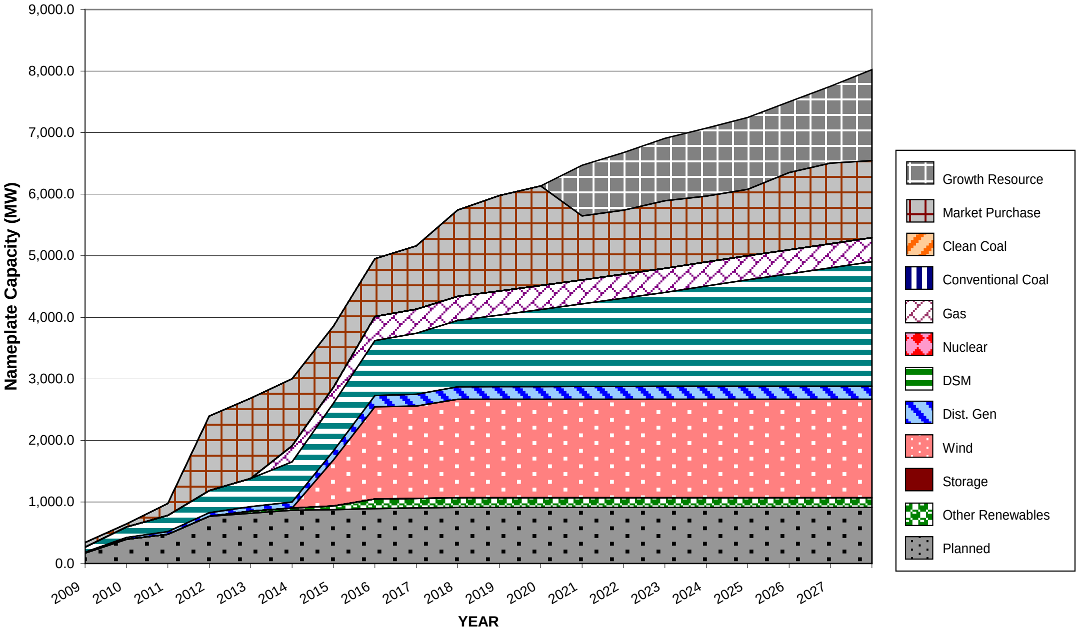
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 05b

PVRR = $41,265



Notes:

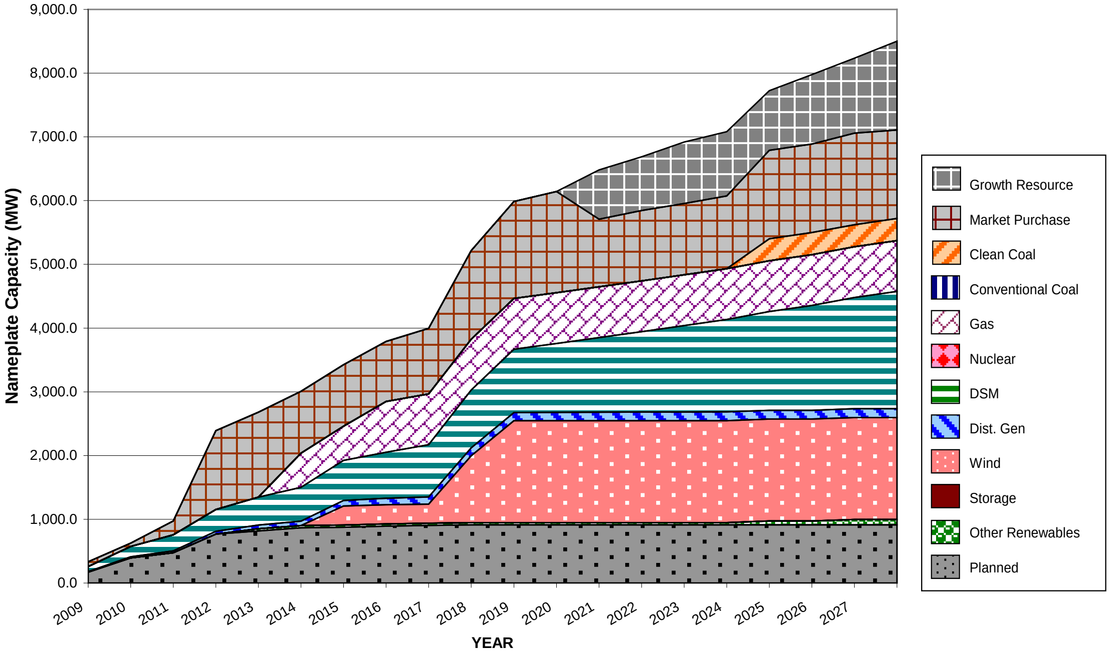
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 05b_CCCT

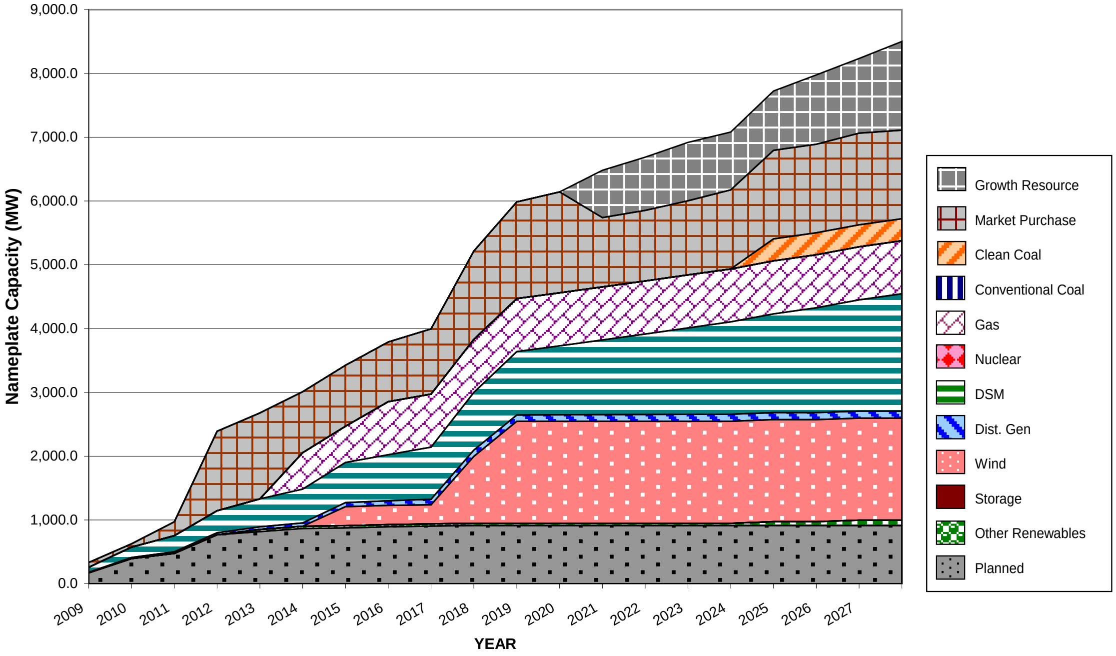
PVRR = $41,325



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 05b_WC_CCCT

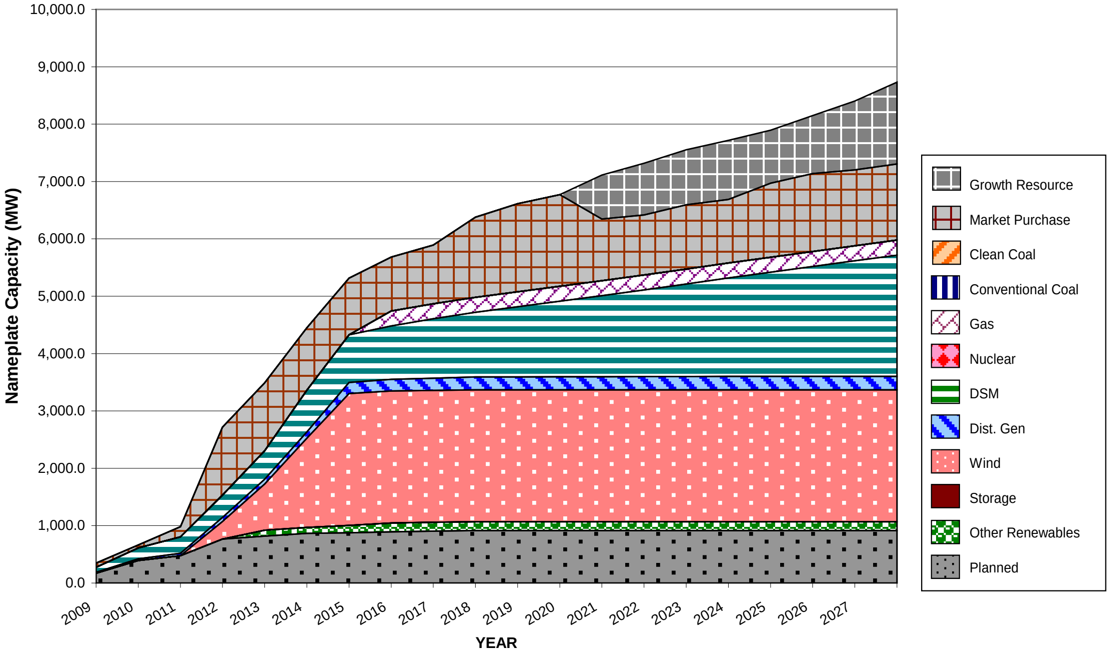
PVRR = $41,271



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 08b

PVRR = $41,922



Notes:

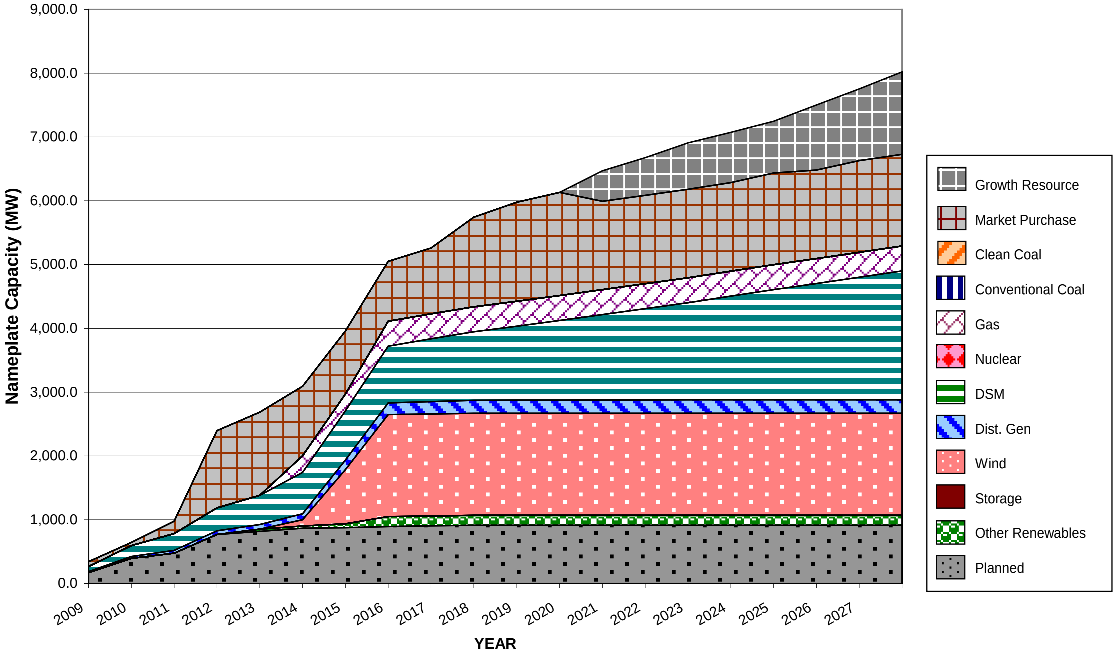
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 09b

PVRR = $40,967

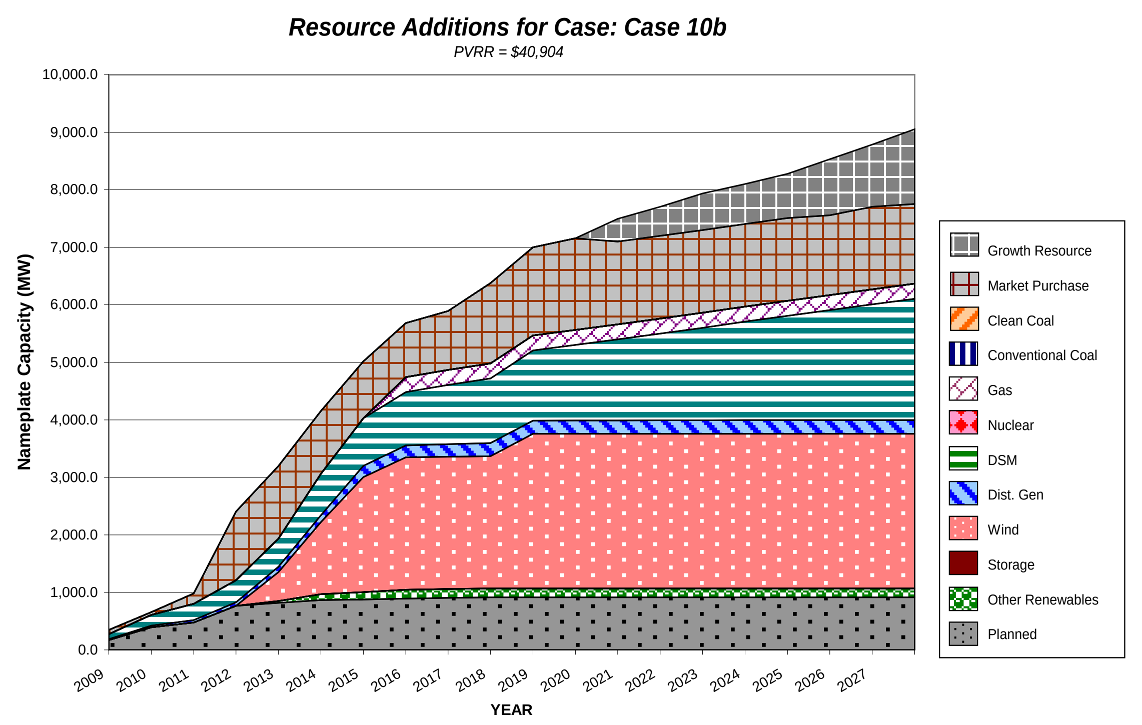


Notes:

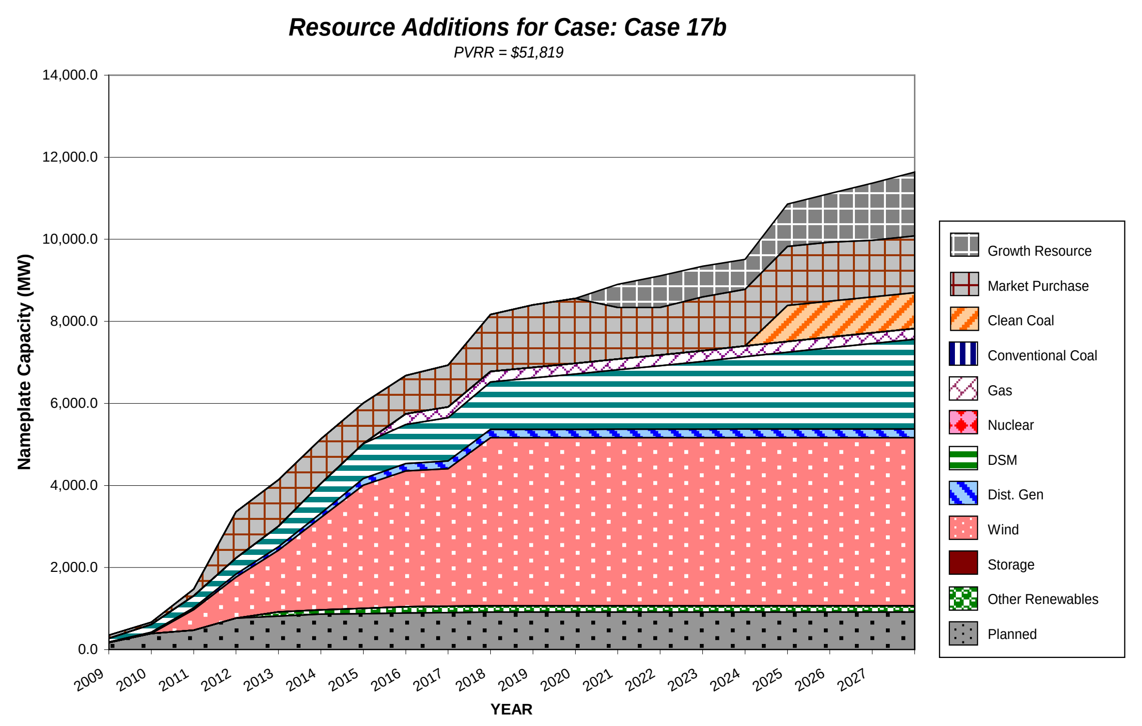
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



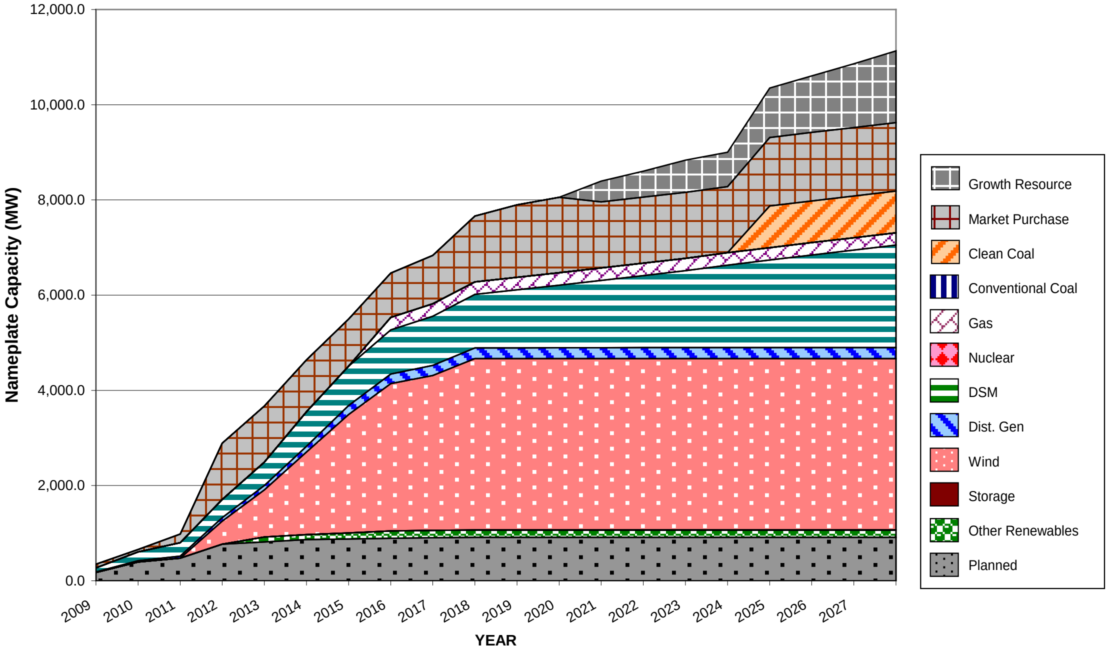
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 18b

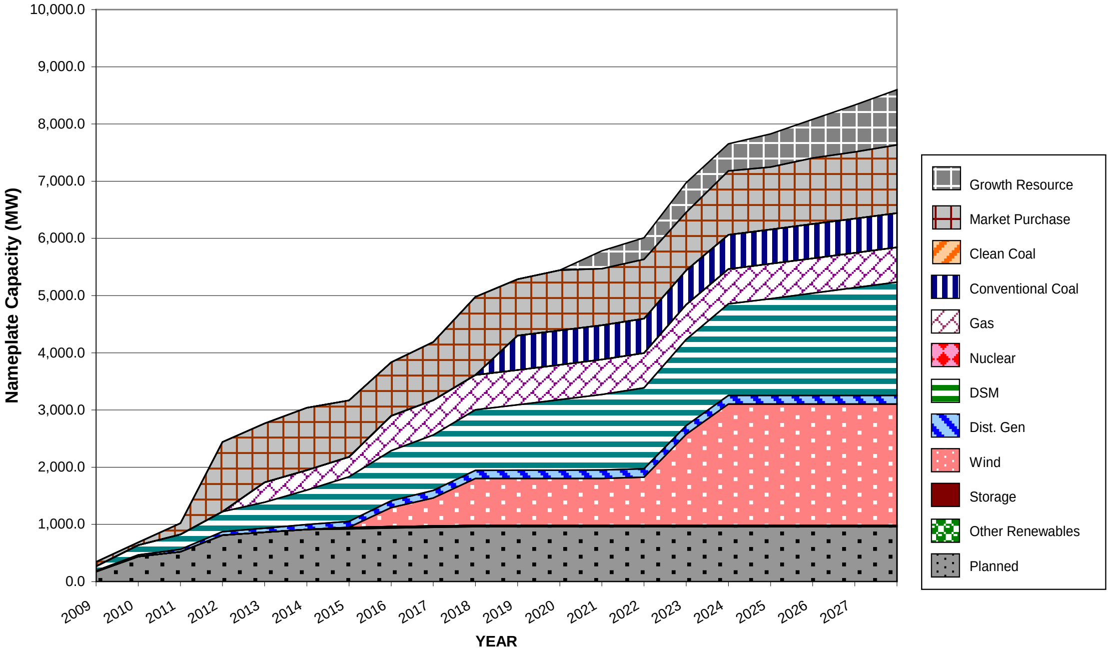
PVRR = $50,597



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 47b

PVRR = $21,785



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

CORE CASES – PIVOT SUMMARY

Table A.4 – Pivot Summary Year 2009 to 2013 (Medium Load Growth Only)

Load	Medium													**2009-2013**
Sum of Capacity			Group											
Co2	Case (Price Curve)	**Year**	**Wind**	**Other Renewables**	**Nuclear**	**Gas**	**Dist. Gen**	**DSM**	**SCPC**	**Clean Coal**	**Storage**	**Growth Resource**	**Market Purchase**	**Planned Resource**
$0	Case 01 (Low - June 2008)	2009					13	9						172
		2010					13	44						222
		2011					13	72					301	82
		2012					13	75					801	899
		2013					13	89					933	49
	Case 01 (Low - June 2008) Total						67	289						1,423
	Case 02 (Medium - June 2008)	2009					8	78						172
		2010					8	87						222
		2011					8	88					219	82
		2012					8	90					714	899
		2013		35			8	93					817	49
	Case 02 (Medium - June 2008) Total			35			41	436						1,423
	Case 03 (High - June 2008)	2009					8	87						172
		2010	500				8	99						222
		2011	500				14	97					129	82
		2012	295				8	98					601	899
		2013		105			8	99					648	49
	Case 03 (High - June 2008) Total		1,295	105			47	480						1,423
$45	Case 05 (Low - June 2008)	2009					8	76						172
		2010					8	87						222
		2011					8	88					220	82
		2012					8	90					716	899
		2013		35			9	95					817	49
	Case 05 (Low - June 2008) Total			35			42	436						1,423
	Case 08 (Medium - June 2008)	2009					10	81						172
		2010					13	92						222
		2011					13	91					200	82
		2012	264				20	93					683	899
		2013	500	35			15	100					758	49
	Case 08 (Medium - June 2008) Total		764	35			72	458						1,423
	Case 09 (Low - Oct 2008)	2009					8	76						172
		2010					8	87						222
		2011					8	88					220	82
		2012					8	90					716	899
		2013		35			9	93					818	49
	Case 09 (Low - Oct 2008) Total			35			42	434						1,423
	Case 10 (Medium - Oct 2008)	2009					8	78						172
		2010					8	91						222
		2011					9	91					213	82
		2012					9	93					705	899
		2013	361	35			9	96					798	49
	Case 10 (Medium - Oct 2008) Total		361	35			44	450						1,423
	Case 11 (High - Oct 2008)	2009					8	86						172
		2010					8	99						222
		2011	64				8	97					196	82
		2012	500				14	99					674	899
		2013	500	105			8	103					663	49
	Case 11 (High - Oct 2008) Total		1,064	105			47	484						1,423
	Case 14 (High - June 2008)	2009					8	90						172
		2010	500				8	103						222
		2011	500				20	98					122	82
		2012	500				9	103					586	899
		2013	500	105			9	104					615	49
	Case 14 (High - June 2008) Total		2,000	105			55	499						1,423
$70	Case 17 (Medium - June 2008)	2009					8	82						172
		2010					8	98						222
		2011	194				9	97					197	82
		2012	500				21	99					673	899
		2013	500	105			9	99					688	49
	Case 17 (Medium - June 2008) Total		1,194	105			56	475						1,423
	Case 18 (Low - Oct 2008)	2009					8	78						172
		2010					9	91						222
		2011					9	91					213	82
		2012	263				21	93					699	899
		2013	500	70			9	100					745	49
	Case 18 (Low - Oct 2008) Total		763	70			57	454						1,423
	Case 19 (Medium - Oct 2008)	2009					8	81						172
		2010					9	92						222
		2011					9	96					207	82
		2012	500				21	98					682	899
		2013	500	105			9	101					695	49
	Case 19 (Medium - Oct 2008) Total		1,000	105			57	468						1,423
	Case 20 (High - Oct 2008)	2009					8	87						172
		2010					8	99						222
		2011	500				8	97					184	82
		2012	500				20	102					631	899
		2013	500	105			8	104					800	49
	Case 20 (High - Oct 2008) Total		1,500	105			53	490						1,423
	Case 22 (High - June 2008)	2009					8	90						172
		2010	500				8	103						222
		2011	500				14	98					122	82
		2012	500				14	103					591	899
		2013	500	105			9	105					605	49
	Case 22 (High - June 2008) Total		2,000	105			54	500						1,423

Load	Medium													**2009-2013**
Sum of Capacity			Group											
Co2	Case (Price Curve)	**Year**	**Wind**	**Other Renewables**	**Nuclear**	**Gas**	**Dist. Gen**	**DSM**	**SCPC**	**Clean Coal**	**Storage**	**Growth Resource**	**Market Purchase**	**Planned Resource**
$100	Case 24 (Medium - June 2008)	2009					9	87						172
		2010	489				9	99						222
		2011	500				9	98					128	82
		2012	500				21	103					596	899
		2013	500	105			9	104					607	49
	Case 24 (Medium - June 2008) Total		1,989	105			59	492						1,423
	Case 25 (Low - Oct 2008)	2009					9	82						172
		2010					9	98						222
		2011	500				9	97					185	82
		2012	500				21	102					661	899
		2013	500	105			9	104					800	49
	Case 25 (Low - Oct 2008) Total		1,500	105			59	483						1,423
	Case 26 (Medium - Oct 2008)	2009					9	87						172
		2010					9	99						222
		2011	500				9	97					182	82
		2012	500				21	103					643	899
		2013	500	105			9	104					800	49
	Case 26 (Medium - Oct 2008) Total		1,500	105			59	490						1,423
	Case 27 (High - Oct 2008)	2009					8	87						172
		2010	500				9	103						222
		2011	500				9	98					126	82
		2012	500				21	103					593	899
		2013	500	105			9	104					800	49
	Case 27 (High - Oct 2008) Total		2,000	105			57	496						1,423
	Case 29 (High - June 2008)	2009					9	91						172
		2010	500				14	109						222
		2011	500				20	106					102	82
		2012	500				21	109					556	899
		2013	500	105			15	110					564	49
	Case 29 (High - June 2008) Total		2,000	105			78	526						1,423

Table A.5 – Pivot Summary Year 2014 to 2020 (Medium Load Growth Only)

Load	Medium													2014-2020
Sum of Capacity			Group											
Co2	Case (Price Curve)	Year	Wind	Other Renewables	Nuclear	Gas	Dist. Gen	DSM	SCPC	Clean Coal	Storage	Growth Resource	Market Purchase	Planned Resource
$0	Case 01 (Low - June 2008)	2014					13	85					1,055	49
		2015					13	162					989	10
		2016				261	13	118					939	18
		2017					8	87					1,039	10
		2018					8	82					1,422	10
		2019					5	82					1,566	
		2020					0	82					1,638	
	Case 01 (Low - June 2008) Total					261	63	699						97
	Case 02 (Medium - June 2008)	2014					8	92					938	49
		2015					8	92					949	10
		2016				261	8	89					933	18
		2017					8	96					1,027	10
		2018	140				10	87	600				863	10
		2019	160				2	87					1,008	
		2020					3	88					1,074	
	Case 02 (Medium - June 2008) Total		300			261	48	630	600					97
	Case 03 (High - June 2008)	2014	135				14	102					749	49
		2015	750	25			8	102					709	10
		2016	223	25			8	101					891	18
		2017	138				8	104					967	10
		2018	750				8	99	790				604	10
		2019	712					97					739	
		2020						97					800	
	Case 03 (High - June 2008) Total		2,708	50			47	702	790					97
$45	Case 05 (Low - June 2008)	2014					9	94					935	49
		2015	300				11	95					936	10
		2016				261	11	95					914	18
		2017					11	97					1,004	10
		2018	750				11	87					1,365	10
		2019	400				3	87					1,500	
		2020					3	88					1,566	
	Case 05 (Low - June 2008) Total		1,450			261	59	642						97
	Case 08 (Medium - June 2008)	2014	286				15	101					859	49
		2015	750	25			22	101					821	10
		2016	193	60			16	107					939	18
		2017	158				11	104					1,010	10
		2018	249				11	92					1,358	10
		2019					3	96					1,500	
		2020					3	95					1,561	
	Case 08 (Medium - June 2008) Total		1,636	85			80	695						97
	Case 09 (Low - Oct 2008)	2014					9	94					937	49
		2015	300				11	95					938	10
		2016				261	11	95					916	18
		2017	444				11	97					996	10
		2018	536				11	87					1,362	10
		2019	305				3	87					1,499	
		2020	15				3	88					1,565	
	Case 09 (Low - Oct 2008) Total		1,600			261	58	642						97
	Case 10 (Medium - Oct 2008)	2014	291				9	101					902	49
		2015	750	25			25	102					867	10
		2016	591	95			16	107					939	18
		2017	158				11	104					1,010	10
		2018	248				11	92					1,358	10
		2019	200				3	96					1,468	
		2020					3	95					1,529	
	Case 10 (Medium - Oct 2008) Total		2,238	120			78	696						97
	Case 11 (High - Oct 2008)	2014	750				14	105					733	49
		2015	750	25			10	104					689	10
		2016	750	25			10	104					863	18
		2017	750				10	105					915	10
		2018	750				10	106	600				726	10
		2019	185				2	97					866	
		2020					2	97					925	
	Case 11 (High - Oct 2008) Total		3,935	50			60	718	600					97
	Case 14 (High - June 2008)	2014	750				9	105					689	49
		2015	750	25			11	104					651	10
		2016	750	25			11	105					790	18
		2017	482				11	106					866	10
		2018	622			0	11	106	600				679	10
		2019	335				3	98					819	
		2020	199				3	98					877	
	Case 14 (High - June 2008) Total		3,888	50		0	58	722	600					97

Load	Medium													**2014-2020**
Sum of Capacity			Group											
$70	Case 17 (Medium - June 2008)	2014	750				9	102					764	49
		2015	750	25			11	102					701	10
		2016	595	25			11	103					875	18
		2017	110				11	112					947	10
		2018	500				11	99					1,287	10
		2019					3	97					1,429	
		2020					3	97					1,487	
	Case 17 (Medium - June 2008) Total		2,706	50			59	713						97
	Case 18 (Low - Oct 2008)	2014	750	35			9	102					810	49
		2015	486	25			11	102					749	10
		2016	400	25			11	101					903	18
		2017	750				11	110					969	10
		2018	750				11	92					1,310	10
		2019					3	96					1,453	
		2020					2	95					1,514	
	Case 18 (Low - Oct 2008) Total		3,136	85			58	698						97
	Case 19 (Medium - Oct 2008)	2014	750				9	102					794	49
		2015	750	25			11	102					707	10
		2016	750	25			11	101					881	18
		2017	585				11	111					944	10
		2018	265				11	98					1,287	10
		2019					3	97					1,429	
		2020					2	97					1,488	
	Case 19 (Medium - Oct 2008) Total		3,100	50			58	708						97
	Case 20 (High - Oct 2008)	2014	750				9	105					720	49
		2015	750	25			10	104					685	10
		2016	750	25			10	104					855	18
		2017	750				10	112					914	10
		2018	750				10	99					1,228	10
		2019	750				2	97					1,368	
		2020	600				2	97					1,426	
	Case 20 (High - Oct 2008) Total		5,100	50			55	719						97
	Case 22 (High - June 2008)	2014	750				9	110					700	49
		2015	750	25			10	112					653	10
		2016	750	25			10	110					807	18
		2017	750				10	113					1,007	10
		2018	750				8	111	600				658	10
		2019	750					102					791	
		2020	700					102					843	
	Case 22 (High - June 2008) Total		5,200	50			47	760	600					97
$100	Case 24 (Medium - June 2008)	2014	750				9	105					706	49
		2015	750	25			11	104					673	10
		2016	750	25			11	104					841	18
		2017	750				11	105					883	10
		2018	750				11	106					1,218	10
		2019	750				2	102					1,355	
		2020	111				2	103					1,411	
	Case 24 (Medium - June 2008) Total		4,611	50			57	729						97
	Case 25 (Low - Oct 2008)	2014	750				9	105					850	49
		2015	750	25			11	104					850	10
		2016	750	25			11	104					1,015	18
		2017	750				11	112					1,530	10
		2018	750				11	99					1,530	10
		2019	750				2	97					1,530	
		2020	175				2	97					1,530	
	Case 25 (Low - Oct 2008) Total		4,675	50			57	719						97
	Case 26 (Medium - Oct 2008)	2014	750				9	105					728	49
		2015	750	25			11	104					800	10
		2016	750	25			11	104					1,009	18
		2017	750				11	112					1,072	10
		2018	750				11	99					1,381	10
		2019	750				2	97					1,423	
		2020	600				2	97					1,482	
	Case 26 (Medium - Oct 2008) Total		5,100	50			57	719						97
	Case 27 (High - Oct 2008)	2014	750				9	110					800	49
		2015	750	25			11	112					800	10
		2016	750	25			11	109					987	18
		2017	750				11	114					1,019	10
		2018	750				11	111					1,352	10
		2019	750				3	103					1,390	
		2020	180				2	103					1,443	
	Case 27 (High - Oct 2008) Total		4,680	50			58	763						97
	Case 29 (High - June 2008)	2014	750				15	112					661	49
		2015	750	25			16	113					716	10
		2016	750	25			16	110					926	18
		2017	750				16	218					850	10
		2018	750				16	110					1,009	10
		2019	750				2	103					1,144	
		2020	700				2	103					1,197	
	Case 29 (High - June 2008) Total		5,200	50			84	870						97

Table A.6 – Pivot Summary Year 2021 to 2028 (Medium Load Growth Only)

Load	Medium													2021-2028
Sum of Capacity			Group											
Co2	Case (Price Curve)	**Year**	**Wind**	**Other Renewables**	**Nuclear**	**Gas**	**Dist. Gen**	**DSM**	**SCPC**	**Clean Coal**	**Storage**	**Growth Resource**	**Market Purchase**	**Planned Resource**
$0	Case 01 (Low - June 2008)	2021						76				407	1,388	
		2022						79				531	1,388	
		2023						80				629	1,438	
		2024						79				708	1,438	
		2025						81				889	1,438	
		2026						88				1,051	1,438	
		2027						89				1,213	1,438	
		2028						85				1,441	1,388	
	Case 01 (Low - June 2008) Total							657						
	Case 02 (Medium - June 200	2021					3	90				268	950	
		2022					3	91				363	966	
		2023	14				3	93				287	1,177	
		2024					3	93				535	995	
		2025					3	92				633	1,068	
		2026					3	95				668	1,188	
		2027	628				3	98				636	1,359	
		2028					1	97				804	1,361	
	Case 02 (Medium - June 2008) Total		641				20	750						
	Case 03 (High - June 2008)	2021						98				450	491	
		2022						99				440	608	
		2023						101				299	881	
		2024						116				289	942	
		2025						107				664	728	
		2026						98				713	834	
		2027						100				198	1,504	
		2028						98				438	1,433	
	Case 03 (High - June 2008) Total							817						
$45	Case 05 (Low - June 2008)	2021	150				3	90				399	1,308	
		2022					3	91				430	1,389	
		2023					2	93				578	1,377	
		2024					2	93				693	1,329	
		2025						100		346		719	1,588	
		2026						97				875	1,588	
		2027						98				981	1,638	
		2028						97				1,200	1,588	
	Case 05 (Low - June 2008) Total		150				9	760		346				
	Case 08 (Medium - June 200	2021					3	95				495	1,206	
		2022					2	97				250	1,558	
		2023					2	100				352	1,588	
		2024					2	105				545	1,453	
		2025						102				575	1,588	
		2026						98				731	1,588	
		2027						100				885	1,588	
		2028						98				1,161	1,543	
	Case 08 (Medium - June 2008) Total						8	797						
	Case 09 (Low - Oct 2008)	2021					3	90				121	1,588	
		2022					3	91				233	1,588	
		2023					2	93				369	1,588	
		2024					2	93				435	1,588	
		2025						100		346		720	1,588	
		2026						97				877	1,588	
		2027						98				1,032	1,588	
		2028						97				1,202	1,588	
	Case 09 (Low - Oct 2008) Total						10	760		346				
	Case 10 (Medium - Oct 2008	2021					2	95				95	1,574	
		2022					2	97				190	1,588	
		2023					2	100				321	1,588	
		2024					2	105				379	1,588	
		2025						102				544	1,588	
		2026						98				700	1,588	
		2027						100				854	1,588	
		2028						98				1,023	1,588	
	Case 10 (Medium - Oct 2008) Total						7	797						
	Case 11 (High - Oct 2008)	2021					2	99				285	778	
		2022					2	100				306	862	
		2023					2	102				321	977	
		2024						117				186	1,162	
		2025						108				288	1,283	
		2026						106				706	1,015	
		2027						100				1,130	850	
		2028						98				1,984	168	
	Case 11 (High - Oct 2008) Total						6	828						
	Case 14 (High - June 2008)	2021	398				3	105				224	785	
		2022					2	106				235	875	
		2023					2	102				724	515	
		2024						117				261	1,029	
		2025						108		466		181	853	
		2026						106				199	984	
		2027						104				151	1,184	
		2028						104				200	1,300	
	Case 14 (High - June 2008) Total		398				7	852		466				

Load	Medium													2021-2028
Sum of Capacity			Group											
Co2	Case (Price Curve)	Year	Wind	Other Renewables	Nuclear	Gas	Dist. Gen	DSM	SCPC	Clean Coal	Storage	Growth Resource	Market Purchase	Planned Resource
$70	Case 17 (Medium - June 20	2021					2	99				107	1,518	
		2022					2	100				144	1,588	
		2023					2	102				274	1,588	
		2024					2	117				323	1,588	
		2025						108		876		778	1,588	
		2026						106				927	1,588	
		2027						104				1,078	1,588	
		2028						104				1,243	1,588	
	Case 17 (Medium - June 2008) Total						7	840		876				
	Case 18 (Low - Oct 2008)	2021					2	95				186	1,468	
		2022					2	97				310	1,452	
		2023					2	101				305	1,588	
		2024					2	116				474	1,468	
		2025						107		876		810	1,588	
		2026						106				960	1,588	
		2027						103				1,062	1,638	
		2028						103				1,227	1,638	
	Case 18 (Low - Oct 2008) Total						7	829		876				
	Case 19 (Medium - Oct 2008	2021					2	99				94	1,532	
		2022					2	100				144	1,588	
		2023					2	102				290	1,572	
		2024					2	117				368	1,543	
		2025						108		876		779	1,588	
		2026						106				928	1,588	
		2027						104				1,079	1,650	
		2028						104				1,194	1,700	
	Case 19 (Medium - Oct 2008) Total						7	840		876				
	Case 20 (High - Oct 2008)	2021					2	99				826	800	
		2022					2	100				743	989	
		2023					2	102				716	1,146	
		2024						117				431	1,481	
		2025			1,600			108		876			939	
		2026						106				11	1,077	
		2027						104				464	800	
		2028						98				2,014	800	
	Case 20 (High - Oct 2008) Total				1,600		6	833		876				
	Case 22 (High - June 2008)	2021						105				154	824	
		2022						106				173	908	
		2023						108				179	1,029	
		2024						117				242	1,016	
		2025			1,600			109		876		123	161	
		2026						107				125	308	
		2027						104				124	639	
		2028						106				165	654	
	Case 22 (High - June 2008) Total				1,600			862		876				
$100	Case 24 (Medium - June 20	2021					2	105				211	1,333	
		2022					2	106				357	1,289	
		2023					2	108				517	1,254	
		2024					2	118				815	1,005	
		2025			3,200			109		876		163	565	
		2026						107				62	683	
		2027						104				34	745	
		2028						106				82	753	
	Case 24 (Medium - June 2008) Total				3,200		6	862		876				
	Case 25 (Low - Oct 2008)	2021					2	99				96	1,530	
		2022					2	100				402	1,268	
		2023					2	102				332	1,530	
		2024					2	117				499	1,349	
		2025						108		876		836	1,468	
		2026						106				1,186	1,268	
		2027						104				1,087	1,518	
		2028						104				1,776	993	
	Case 25 (Low - Oct 2008) Total						6	840		876				
	Case 26 (Medium - Oct 2008	2021					2	99				613	1,063	
		2022					2	100				570	1,094	
		2023					2	102				676	1,117	
		2024					2	117				502	1,341	
		2025			3,200			108		876			731	
		2026						106				11	257	
		2027						104				35	268	
		2028						104				82	277	
	Case 26 (Medium - Oct 2008) Total				3,200		6	840		876				
	Case 27 (High - Oct 2008)	2021					2	105				245	1,330	
		2022					2	107				482	1,194	
		2023					2	108				435	1,366	
		2024						117				374	1,477	
		2025			3,200			108		876			1,280	
		2026						106				930	1,480	
		2027						99				431	1,480	
		2028						97				2,304	517	
	Case 27 (High - Oct 2008) Total				3,200		5	846		876				
	Case 29 (High - June 2008)	2021					2	106				601	728	
		2022					2	107				695	736	
		2023					2	110				809	745	
		2024						135				878	713	
		2025			3,200			110		1,342		140	81	
		2026						112				137	501	
		2027						112				148	125	
		2028						107				187	141	
	Case 29 (High - June 2008) Total				3,200		5	898		1,342				

Core Cases – 20-Year Summary by Scenario Variable

This section provides the 47 core cases 20-Year summarization for Load Growth, CO2 Tax Levels and Natural Gas Forward Price Curves. Additionally a Minimum and Maximum value for each resource group is provide at the bottom.

Table A.7 – 20-year Summary by Scenario Variable, Load Growth

Sum of 20 Year (MW)				Resource Group												
Load	CASE	Gas	CO2	**SCPC**	**IGCC CCS**	**SCPC CCS**	**Gas**	**Dist. Gen**	**Other Renewables**	**Wind**	**Storage**	**Nuclear**	**Mkt Purchases**	**Planned Resource**	**DSM 1**	**DSM 2**
Low	Case 04	Low - June 2008	$45			346		110	35	300			394	1,520		1,801
	Case 07	Medium - June 2008	$45			346		110	85	1,800			300	1,520		1,857
	Case 13	High - June 2008	$45	600				95	155	4,800			152	1,520		2,038
	Case 16	High - June 2008	$70			876		122	155	3,599			219	1,520		1,990
	Case 21	High - June 2008	$70			876		95	155	6,202		1,600	194	1,520		2,058
	Case 23	Medium - June 2008	$100			876		122	155	6,600		3,200	242	1,520		2,045
	Case 28	High - June 2008	$100			876		95	155	5,800		3,200	217	1,520		2,036
Medium	Case 01	Low - June 2008	$0				261	130					1,960	1,520	108	1,537
	Case 02	Medium - June 2008	$0	600			261	109	35	941			1,405	1,520	2	1,815
	Case 03	High - June 2008	$0	790				95	155	4,003			1,150	1,520	7	1,992
	Case 05	Low - June 2008	$45			346	261	110	35	1,600			1,823	1,520	2	1,835
	Case 08	Medium - June 2008	$45					160	120	2,400			1,714	1,520	7	1,942
	Case 09	Low - Oct 2008	$45			346	261	110	35	1,600			1,757	1,520	2	1,834
	Case 10	Medium - Oct 2008	$45					129	155	2,600			1,637	1,520	7	1,936
	Case 11	High - Oct 2008	$45	600				114	155	5,000			1,368	1,520	7	2,024
	Case 14	High - June 2008	$45	600	466			120	155	6,287			983	1,520	7	2,066
	Case 17	Medium - June 2008	$70			876		122	155	3,900			1,693	1,520	7	2,020
	Case 18	Low - Oct 2008	$70			876		122	155	3,900			1,756	1,520	7	1,974
	Case 19	Medium - Oct 2008	$70			876		122	155	4,100			1,703	1,520	7	2,009
	Case 20	High - Oct 2008	$70			876		114	155	6,600		1,600	1,493	1,520	7	2,035
	Case 22	High - June 2008	$70	600		876		101	155	7,200		1,600	776	1,520	7	2,115
	Case 24	Medium - June 2008	$100			876		122	155	6,600		3,200	1,082	1,520	7	2,076
	Case 25	Low - Oct 2008	$100			876		122	155	6,175			1,847	1,520	7	2,035
	Case 26	Medium - Oct 2008	$100			876		122	155	6,600		3,200	1,095	1,520	7	2,042
	Case 27	High - Oct 2008	$100			876		120	155	6,680		3,200	1,622	1,520	7	2,098
	Case 29	High - June 2008	$100		466	876		167	155	7,200		3,200	1,024	1,520	110	2,183
	Case 46	Medium - Oct 2008	Cap-and-Trade	600			174	151		1,388			1,365	1,520	19	1,825
	Case 47	Medium - Oct 2008	Cap-and-Trade	600			174	151		1,344			1,361	1,520	29	1,822
High	Case 06	Low - June 2008	$45				1,838	209	155	1,600			2,306	1,520	126	1,983
	Case 12	Medium - June 2008	$45	600			888	169	155	2,299	805		2,311	1,520	126	2,082
	Case 15	High - June 2008	$45	600	466		261	169	655	6,599		1,600	1,719	1,520	125	2,163
			Min	600	466	346	174	95	35	300	805	1,600	152	1,520	2	1,537
			Max	790	466	876	1,838	209	655	7,200	805	3,200	2,311	1,520	126	2,183

Table A.8 – 20-year Summary by Scenario Variable, CO_2 level

Sum of 20 Year (MW)				Resource Group												
CO2	CASE	Load	Gas	**SCPC**	**SCPC CCS**	**IGCC CCS**	**Gas**	**Dist. Gen**	**Wind**	**Other Renewables**	**Storage**	**Nuclear**	**Mkt Purchases**	**Planned Resource**	**DSM 1**	**DSM 2**
$0	Case 01	Medium	Low - June 2008				261	130					1,960	1,520	108	1,537
	Case 02	Medium	Medium - June 2008	600			261	109	941	35			1,405	1,520	2	1,815
	Case 03	Medium	High - June 2008	790				95	4,003	155			1,150	1,520	7	1,992
$45	Case 04	Low	Low - June 2008		346			110	300	35			394	1,520		1,801
	Case 05	Medium	Low - June 2008		346		261	110	1,600	35			1,823	1,520	2	1,835
	Case 06	High	Low - June 2008				1,838	209	1,600	155			2,306	1,520	126	1,983
	Case 07	Low	Medium - June 2008		346			110	1,800	85			300	1,520		1,857
	Case 08	Medium	Medium - June 2008					160	2,400	120			1,714	1,520	7	1,942
	Case 09	Medium	Low - Oct 2008		346		261	110	1,600	35			1,757	1,520	2	1,834
	Case 10	Medium	Medium - Oct 2008					129	2,600	155			1,637	1,520	7	1,936
	Case 11	Medium	High - Oct 2008	600				114	5,000	155			1,368	1,520	7	2,024
	Case 12	High	Medium - June 2008	600			888	169	2,299	155	805		2,311	1,520	126	2,082
	Case 13	Low	High - June 2008	600				95	4,800	155			152	1,520		2,038
	Case 14	Medium	High - June 2008	600		466		120	6,287	155			983	1,520	7	2,066
	Case 15	High	High - June 2008	600		466	261	169	6,599	655		1,600	1,719	1,520	125	2,163
$70	Case 16	Low	High - June 2008		876			122	3,599	155			219	1,520		1,990
	Case 17	Medium	Medium - June 2008		876			122	3,900	155			1,693	1,520	7	2,020
	Case 18	Medium	Low - Oct 2008		876			122	3,900	155			1,756	1,520	7	1,974
	Case 19	Medium	Medium - Oct 2008		876			122	4,100	155			1,703	1,520	7	2,009
	Case 20	Medium	High - Oct 2008		876			114	6,600	155		1,600	1,493	1,520	7	2,035
	Case 21	Low	High - June 2008		876			95	6,202	155		1,600	194	1,520		2,058
	Case 22	Medium	High - June 2008	600	876			101	7,200	155		1,600	776	1,520	7	2,115
$100	Case 23	Low	Medium - June 2008		876			122	6,600	155		3,200	242	1,520		2,045
	Case 24	Medium	Medium - June 2008		876			122	6,600	155		3,200	1,082	1,520	7	2,076
	Case 25	Medium	Low - Oct 2008		876			122	6,175	155			1,847	1,520	7	2,035
	Case 26	Medium	Medium - Oct 2008		876			122	6,600	155		3,200	1,095	1,520	7	2,042
	Case 27	Medium	High - Oct 2008		876			120	6,680	155		3,200	1,622	1,520	7	2,098
	Case 28	Low	High - June 2008		876			95	5,800	155		3,200	217	1,520		2,036
	Case 29	Medium	High - June 2008		876	466		167	7,200	155		3,200	1,024	1,520	110	2,183
Cap-and-Trade	Case 46	Medium	Medium - Oct 2008	600			174	151	1,388				1,365	1,520	19	1,825
	Case 47	Medium	Medium - Oct 2008	600			174	151	1,344				1,361	1,520	29	1,822
			Min	600	346	466	174	95	300	35	805	1,600	152	1,520	2	1,537
			Max	790	876	466	1,838	209	7,200	655	805	3,200	2,311	1,520	126	2,183

Table A.9 – 20-year Summary by Scenario Variable, Natural Gas Price Forecast

Sum of 20 Year (MW)				Resource Group												
Gas	CASE	Load	CO2	**SCPC**	**SCPC CCS**	**IGCC CCS**	**Gas**	**Dist. Gen**	**Other Renewables**	**Wind**	**Storage**	**Nuclear**	**Mkt Purchases**	**Planned Resource**	**DSM 1**	**DSM 2**
Low - June 2008	Case 01	Medium	$0				261	130					1,960	1,520	108	1,537
	Case 04	Low	$45		346			110	35	300			394	1,520		1,801
	Case 05	Medium	$45		346		261	110	35	1,600			1,823	1,520	2	1,835
	Case 06	High	$45				1,838	209	155	1,600			2,306	1,520	126	1,983
Medium - June 2008	Case 02	Medium	$0	600			261	109	35	941			1,405	1,520	2	1,815
	Case 07	Low	$45		346			110	85	1,800			300	1,520		1,857
	Case 08	Medium	$45					160	120	2,400			1,714	1,520	7	1,942
	Case 12	High	$45	600			888	169	155	2,299	805		2,311	1,520	126	2,082
	Case 17	Medium	$70		876			122	155	3,900			1,693	1,520	7	2,020
	Case 23	Low	$100		876			122	155	6,600		3,200	242	1,520		2,045
	Case 24	Medium	$100		876			122	155	6,600		3,200	1,082	1,520	7	2,076
High - June 2008	Case 03	Medium	$0	790				95	155	4,003			1,150	1,520	7	1,992
	Case 13	Low	$45	600				95	155	4,800			152	1,520		2,038
	Case 14	Medium	$45	600		466		120	155	6,287			983	1,520	7	2,066
	Case 15	High	$45	600		466	261	169	655	6,599		1,600	1,719	1,520	125	2,163
	Case 16	Low	$70		876			122	155	3,599			219	1,520		1,990
	Case 21	Low	$70		876			95	155	6,202		1,600	194	1,520		2,058
	Case 22	Medium	$70	600	876			101	155	7,200		1,600	776	1,520	7	2,115
	Case 28	Low	$100		876			95	155	5,800		3,200	217	1,520		2,036
	Case 29	Medium	$100		876	466		167	155	7,200		3,200	1,024	1,520	110	2,183
Low - Oct 2008	Case 09	Medium	$45		346		261	110	35	1,600			1,757	1,520	2	1,834
	Case 18	Medium	$70		876			122	155	3,900			1,756	1,520	7	1,974
	Case 25	Medium	$100		876			122	155	6,175			1,847	1,520	7	2,035
Medium - Oct 2008	Case 10	Medium	$45					129	155	2,600			1,637	1,520	7	1,936
	Case 19	Medium	$70		876			122	155	4,100			1,703	1,520	7	2,009
	Case 26	Medium	$100		876			122	155	6,600		3,200	1,095	1,520	7	2,042
	Case 46	Medium	Cap-and-Trade	600			174	151		1,388			1,365	1,520	19	1,825
	Case 47	Medium	Cap-and-Trade	600			174	151		1,344			1,361	1,520	29	1,822
High - Oct 2008	Case 11	Medium	$45	600				114	155	5,000			1,368	1,520	7	2,024
	Case 20	Medium	$70		876			114	155	6,600		1,600	1,493	1,520	7	2,035
	Case 27	Medium	$100		876			120	155	6,680		3,200	1,622	1,520	7	2,098
			Min	600	346	466	174	95	35	300	805	1,600	152	1,520	2	1,537
			Max	790	876	466	1,838	209	655	7,200	805	3,200	2,311	1,520	126	2,183

Resource Type Summary

In the following tables, resource additions are reported at capacity megawatts accrued as of the year listed.

Table A.10 – Total Aggregate Capacity Additions for 20 years

Aggregate Resource Additions

(Capacity MW) (Does not include Short Term Resources)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	195	474	641	1,628	1,780	1,927	2,113	2,524	2,629	2,730	2,817	2,900	2,976	3,055	3,134	3,213	3,294	3,382	3,471	3,556
Case 02	258	575	753	1,751	1,935	2,085	2,195	2,572	2,685	3,532	3,781	3,872	3,964	4,058	4,168	4,264	4,358	4,456	5,185	5,283
Case 03	267	1,096	1,789	3,090	3,351	3,651	4,546	4,922	5,182	6,840	7,648	7,745	7,842	7,942	8,043	8,159	8,266	8,365	8,464	8,562
Case 04	253	569	746	1,744	1,926	2,076	2,328	2,446	2,721	2,828	2,917	3,007	3,100	3,194	3,290	3,386	3,824	3,920	4,016	4,111
Case 05	256	573	750	1,748	1,935	2,088	2,503	2,888	3,005	3,864	4,353	4,444	4,686	4,780	4,875	4,970	5,417	5,513	5,612	5,709
Case 06	266	593	781	2,052	2,266	2,772	3,711	4,257	4,380	5,216	5,314	5,886	6,687	6,788	6,890	7,008	7,115	7,221	7,325	7,429
Case 07	261	581	762	1,790	2,476	2,975	3,865	3,988	4,207	4,416	4,506	4,597	4,695	4,794	4,890	4,987	5,081	5,177	5,274	5,718
Case 08	263	590	777	2,053	2,751	3,201	4,109	4,503	4,786	5,147	5,247	5,344	5,442	5,542	5,643	5,750	5,851	5,950	6,050	6,148
Case 09	256	573	751	1,749	1,934	2,086	2,501	2,885	3,447	4,092	4,486	4,591	4,684	4,778	4,873	4,969	5,415	5,512	5,610	5,707
Case 10	259	579	761	1,763	2,314	2,764	3,676	4,502	4,785	5,147	5,446	5,543	5,641	5,740	5,841	5,948	6,050	6,148	6,248	6,346
Case 11	267	595	847	2,359	3,123	4,041	4,941	5,848	6,724	8,200	8,485	8,584	8,685	8,787	8,891	9,008	9,116	9,221	9,321	9,419
Case 12	271	604	797	2,263	3,295	3,883	5,298	5,478	5,604	6,323	6,558	6,828	7,049	7,156	7,266	7,400	7,509	8,026	8,523	8,643
Case 13	267	1,096	1,790	3,305	4,070	4,982	5,879	6,295	6,642	7,983	8,105	8,203	8,467	8,567	8,669	8,786	8,894	9,000	9,104	9,207
Case 14	271	1,104	1,804	3,315	4,081	4,994	5,895	6,803	7,413	8,762	9,198	9,497	10,003	10,111	10,215	10,333	10,906	11,013	11,117	11,221
Case 15	281	1,125	1,840	3,362	4,147	5,330	6,500	7,773	8,657	10,132	10,987	11,209	11,316	11,425	11,534	11,669	13,844	13,950	14,054	14,158
Case 16	262	583	869	2,387	3,149	4,059	4,957	5,496	5,829	6,345	6,444	6,541	6,640	6,742	6,845	6,964	7,947	8,054	8,158	8,262
Case 17	262	589	971	2,490	3,252	4,163	5,061	5,813	6,057	6,677	6,777	6,877	6,978	7,079	7,183	7,301	8,285	8,391	8,496	8,599
Case 18	259	580	762	2,039	2,767	3,712	4,346	4,902	5,782	6,646	6,745	6,841	6,939	7,038	7,140	7,258	8,241	8,347	8,450	8,553
Case 19	262	583	770	2,289	3,053	3,963	4,861	5,767	6,483	6,867	6,966	7,066	7,167	7,269	7,372	7,490	8,474	8,581	8,685	8,789
Case 20	267	596	1,284	2,805	3,571	4,484	5,384	6,291	7,173	8,043	8,892	9,591	9,692	9,794	9,898	10,015	12,599	12,705	12,809	12,907
Case 21	271	1,104	1,798	3,314	4,080	4,992	5,890	6,795	7,669	8,536	9,086	9,184	9,284	9,384	9,486	9,604	12,188	12,295	12,399	12,505
Case 22	271	1,104	1,799	3,315	4,082	5,000	5,907	6,820	7,703	9,181	10,034	10,836	10,941	11,046	11,155	11,272	13,857	13,964	14,068	14,174
Case 23	267	905	1,594	3,117	3,884	4,797	5,697	6,604	7,480	8,350	9,200	9,591	9,692	9,794	9,897	10,016	14,201	14,307	14,412	14,517
Case 24	268	1,087	1,776	3,300	4,067	4,980	5,880	6,788	7,664	8,541	9,396	9,611	9,717	9,825	9,935	10,054	14,238	14,345	14,450	14,556
Case 25	262	592	1,280	2,803	3,570	4,483	5,383	6,291	7,174	8,044	8,893	9,167	9,268	9,369	9,472	9,591	10,575	10,681	10,786	10,889
Case 26	267	598	1,286	2,810	3,576	4,490	5,390	6,298	7,181	8,051	8,900	9,599	9,699	9,801	9,904	10,023	14,207	14,313	14,417	14,521
Case 27	267	1,101	1,790	3,314	4,081	4,999	5,907	6,821	7,705	8,587	9,443	9,729	9,836	9,944	10,054	10,171	14,354	14,460	14,560	14,656
Case 28	271	1,104	1,799	3,315	4,081	4,993	5,891	6,796	7,670	8,537	8,685	8,783	8,882	8,983	9,085	9,202	13,381	13,480	13,581	13,682
Case 29	272	1,116	1,825	3,353	4,132	5,057	5,971	6,891	7,885	8,771	9,627	10,432	10,539	10,648	10,759	10,894	15,545	15,658	15,770	15,877
Case 30	267	595	784	1,941	2,644	3,599	4,499	5,442	6,324	7,194	8,045	8,900	9,757	10,215	10,325	10,460	15,110	15,217	15,329	15,436
Case 31	272	1,106	1,815	3,331	4,104	5,024	5,932	6,847	7,731	8,614	9,469	10,274	10,382	10,491	10,602	10,738	14,924	15,031	15,135	15,238
Case 33	282	1,127	1,837	3,409	4,442	5,644	6,617	8,118	9,018	10,499	11,182	11,948	12,812	12,928	13,046	13,185	13,309	13,835	14,341	14,452
Case 34	262	583	1,121	2,592	3,284	4,198	4,595	4,762	5,020	5,883	6,698	6,795	6,894	6,993	7,095	7,202	7,304	7,402	7,502	7,600
Case 35	271	1,105	1,806	3,316	4,047	4,959	5,856	6,759	7,209	8,358	8,455	8,552	8,651	8,751	8,852	8,968	9,070	9,168	9,268	9,365
Case 36	266	595	788	2,314	3,052	3,970	4,871	5,784	6,544	6,995	7,105	8,194	8,294	8,396	8,499	8,618	8,726	8,832	8,936	9,040
Case 37	271	1,104	1,798	3,314	4,046	4,958	5,856	6,763	7,637	8,511	8,622	12,796	12,895	12,996	13,098	13,215	13,324	13,431	13,535	13,641
Case 38	267	594	785	1,796	2,203	2,369	2,822	3,236	3,517	4,380	4,993	5,090	5,188	5,288	5,389	5,496	5,598	5,703	5,807	5,909
Case 39	276	893	1,593	3,108	3,845	4,372	5,275	5,545	5,722	6,692	6,790	6,888	6,992	7,116	7,224	7,358	7,469	7,584	7,699	7,865
Case 40	266	591	777	1,782	1,974	2,133	2,417	2,864	3,138	3,994	4,831	5,127	5,217	5,314	5,412	5,516	6,228	6,325	6,690	6,788
Case 41	267	593	781	2,104	2,874	3,421	4,338	4,762	4,886	4,999	5,098	5,195	5,293	5,392	5,494	5,600	5,702	5,800	5,900	5,999
Case 42	262	589	1,120	2,639	3,402	4,312	5,209	6,081	6,257	6,628	6,728	6,828	6,929	7,031	7,134	7,252	8,236	8,342	8,447	8,550
Case 43	277	1,116	1,811	3,340	4,112	5,036	5,949	6,973	7,849	8,720	9,574	9,778	9,884	9,991	10,101	10,221	14,405	14,512	14,617	14,722
Case 44	263	585	768	1,771	1,927	2,085	2,266	2,862	3,637	5,091	5,749	6,620	6,823	7,035	7,428	8,274	9,153	9,430	9,736	10,017
Case 45	251	560	958	2,455	2,605	2,754	2,867	3,280	3,397	4,104	4,195	4,287	4,380	4,474	4,765	4,861	4,978	5,099	5,195	5,289
Case 46	263	586	969	1,973	2,301	2,599	2,881	3,130	3,247	3,356	4,345	4,435	4,528	4,622	5,161	5,301	5,394	5,489	5,585	5,679
Case 47	263	585	768	1,771	2,101	2,259	2,381	2,871	3,145	3,585	4,274	4,388	4,504	4,626	5,115	5,263	5,356	5,451	5,547	5,640
Case 48	270	596	780	2,068	2,760	3,259	4,156	4,505	4,789	5,177	5,276	5,374	5,472	5,572	5,674	5,781	5,882	5,981	6,081	6,179

Table A.11 – Total Wind Aggregate Capacity Additions for 20 years

Wind

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	144	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263
Case 02	144	263	263	263	263	263	263	263	263	403	563	563	563	563	576	576	576	576	1,204	1,204
Case 03	144	763	1,263	1,558	1,558	1,693	2,443	2,666	2,804	3,554	4,266	4,266	4,266	4,266	4,266	4,266	4,266	4,266	4,266	4,266
Case 04	144	263	263	263	263	263	403	403	563	563	563	563	563	563	563	563	563	563	563	563
Case 05	144	263	263	263	263	263	563	563	563	1,313	1,713	1,713	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
Case 06	144	263	263	263	263	403	563	916	916	1,167	1,167	1,167	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
Case 07	144	263	263	290	790	1,136	1,886	1,886	1,963	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063
Case 08	144	263	263	527	1,027	1,313	2,063	2,256	2,414	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663
Case 09	144	263	263	263	263	263	563	563	1,007	1,543	1,848	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
Case 10	144	263	263	263	624	915	1,665	2,256	2,414	2,663	2,863	2,863	2,863	2,863	2,863	2,863	2,863	2,863	2,863	2,863
Case 11	144	263	327	827	1,327	2,077	2,827	3,577	4,327	5,077	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263
Case 12	144	263	263	704	1,204	1,542	2,170	2,170	2,170	2,170	2,305	2,466	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562
Case 13	144	763	1,263	1,763	2,263	3,013	3,763	4,024	4,248	4,873	4,897	4,897	5,063	5,063	5,063	5,063	5,063	5,063	5,063	5,063
Case 14	144	763	1,263	1,763	2,263	3,013	3,763	4,513	4,995	5,618	5,953	6,151	6,550	6,550	6,550	6,550	6,550	6,550	6,550	6,550
Case 15	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	6,862	6,862	6,862	6,862	6,862	6,862	6,862	6,862	6,862
Case 16	144	263	367	867	1,367	2,117	2,867	3,252	3,460	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862
Case 17	144	263	457	957	1,457	2,207	2,957	3,552	3,662	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163
Case 18	144	263	263	526	1,026	1,776	2,263	2,663	3,413	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163
Case 19	144	263	263	763	1,263	2,013	2,763	3,513	4,098	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363
Case 20	144	263	763	1,263	1,763	2,513	3,263	4,013	4,763	5,513	6,263	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 21	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465
Case 22	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 23	144	572	1,072	1,572	2,072	2,822	3,572	4,322	5,072	5,822	6,572	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 24	144	752	1,252	1,752	2,252	3,002	3,752	4,502	5,252	6,002	6,752	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 25	144	263	763	1,263	1,763	2,513	3,263	4,013	4,763	5,513	6,263	6,438	6,438	6,438	6,438	6,438	6,438	6,438	6,438	6,438
Case 26	144	263	763	1,263	1,763	2,513	3,263	4,013	4,763	5,513	6,263	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 27	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	6,943	6,943	6,943	6,943	6,943	6,943	6,943	6,943	6,943
Case 28	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,063	6,063	6,063	6,063	6,063	6,063	6,063	6,063	6,063	6,063
Case 29	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 30	144	263	263	413	913	1,663	2,413	3,163	3,913	4,663	5,413	6,163	6,913	7,263	7,263	7,263	7,263	7,263	7,263	7,263
Case 31	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 33	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,582	6,713	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 34	144	263	616	1,074	1,574	2,324	2,563	2,563	2,696	3,446	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163
Case 35	144	763	1,263	1,763	2,263	3,013	3,763	4,511	4,837	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263
Case 36	144	263	263	763	1,263	2,013	2,763	3,513	4,136	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463
Case 37	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025
Case 38	144	263	263	263	471	471	771	961	1,118	1,868	2,381	2,381	2,381	2,381	2,381	2,381	2,381	2,381	2,381	2,381
Case 39	144	541	1,041	1,541	2,041	2,395	3,145	3,145	3,192	3,445	3,445	3,445	3,445	3,462	3,462	3,462	3,462	3,462	3,462	3,518
Case 40	144	263	263	263	263	263	403	596	754	1,504	2,254	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463
Case 41	144	263	263	570	1,070	1,447	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197
Case 42	144	263	607	1,107	1,607	2,357	3,107	3,561	3,611	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863
Case 43	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 44	144	263	263	263	263	263	263	598	1,259	2,009	2,582	3,332	3,444	3,563	3,862	4,612	5,362	5,542	5,750	5,936
Case 45	144	263	484	984	984	984	984	984	984	984	984	984	984	984	1,144	1,144	1,144	1,144	1,144	1,144
Case 46	144	263	463	463	463	603	763	863	863	863	1,163	1,163	1,163	1,163	1,606	1,651	1,651	1,651	1,651	1,651
Case 47	144	263	263	263	263	263	263	596	754	1,085	1,085	1,110	1,132	1,161	1,555	1,607	1,607	1,607	1,607	1,607
Case 48	144	263	263	544	1,044	1,313	2,063	2,234	2,388	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663

Table A.12 – Total Market Purchases Capacity Additions for 20 years

Market Purchase

(Figures shown are megawatts acquired in each year. Annual figures are not additive.)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01			301	801	933	1,055	989	939	1,039	1,422	1,566	1,638	1,388	1,388	1,438	1,438	1,438	1,438	1,438	1,388
Case 02			219	714	817	938	949	933	1,027	863	1,008	1,074	950	966	1,177	995	1,068	1,188	1,359	1,361
Case 03			129	601	648	749	709	891	967	604	739	800	491	608	881	942	728	834	1,504	1,433
Case 04				335	322	321	197	278	237	475	488	421	281	251	240	186	329	338	339	349
Case 05			220	716	817	935	936	914	1,004	1,365	1,500	1,566	1,308	1,389	1,377	1,329	1,588	1,588	1,638	1,588
Case 06		39	469	841	1,058	1,089	644	939	1,179	1,288	1,582	1,381	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638
Case 07				321	292	279	123	201	134	370	382	315	180	146	134	81	105	113	115	400
Case 08			200	683	758	859	821	939	1,010	1,358	1,500	1,561	1,206	1,558	1,588	1,453	1,588	1,588	1,588	1,543
Case 09			220	716	818	937	938	916	996	1,362	1,499	1,565	1,588	1,588	1,588	1,588	1,588	1,588	1,588	1,588
Case 10			213	705	798	902	867	939	1,010	1,358	1,468	1,529	1,574	1,588	1,588	1,588	1,588	1,588	1,588	1,588
Case 11			196	674	663	733	689	863	915	726	866	925	778	862	977	1,162	1,283	1,015	850	168
Case 12		30	457	1,037	943	1,089	633	939	1,177	1,173	1,445	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,700
Case 13				303	471	193	60	52	52	80	108	106								
Case 14			122	586	615	689	651	790	866	679	819	877	785	875	515	1,029	853	984	1,184	1,300
Case 15			367	940	1,075	1,089	989	939	1,160	1,148	1,437	1,638	1,588	1,588	1,374	1,588	1,237	1,571	1,588	1,638
Case 16				308	204	217	85	80	80	183	188	135					170	171	167	172
Case 17			197	673	688	764	701	875	947	1,287	1,429	1,487	1,518	1,588	1,588	1,588	1,588	1,588	1,588	1,588
Case 18			213	699	745	810	749	903	969	1,310	1,453	1,514	1,468	1,452	1,588	1,468	1,588	1,588	1,638	1,638
Case 19			207	682	695	794	707	881	944	1,287	1,429	1,488	1,532	1,588	1,572	1,543	1,588	1,588	1,650	1,700
Case 20			184	631	800	720	685	855	914	1,228	1,368	1,426	800	989	1,146	1,481	939	1,077	800	800
Case 21				302	198	200	60	54	453	72	97	94							480	480
Case 22			122	591	605	700	653	807	1,007	658	791	843	824	908	1,029	1,016	161	308	639	654
Case 23				305	201	209	79	67	55	90	112	109					480	480	480	480
Case 24			128	596	607	706	673	841	883	1,218	1,355	1,411	1,333	1,289	1,254	1,005	565	683	745	753
Case 25			185	661	800	850	850	1,015	1,530	1,530	1,530	1,530	1,530	1,268	1,530	1,349	1,468	1,268	1,518	993
Case 26			182	643	800	728	800	1,009	1,072	1,381	1,423	1,482	1,063	1,094	1,117	1,341	731	257	268	277
Case 27			126	593	800	800	800	987	1,019	1,352	1,390	1,443	1,330	1,194	1,366	1,477	1,280	1,480	1,480	517
Case 28				302	197	479	470	453	445	70	94	92						400		
Case 29			102	556	564	661	716	926	850	1,009	1,144	1,197	728	736	745	713	81	501	125	141
Case 30			197	681	764	791	738	863	922	1,256	1,373	1,414	1,319	1,287	1,276	1,191	550	70	86	88
Case 31			115	570	586	671	626	762	824	1,172	1,308	1,348	1,249	1,220	1,187	1,108	1,136	1,137	1,153	120
Case 33		18	371	889	846	850	984	833	1,014	814	1,092	837	838	838	838	838	838	838	838	838
Case 34			200	653	728	803	772	939	1,019	1,360	1,493	1,554	1,509	1,588	1,588	1,634	1,588	1,588	1,588	1,588
Case 35			122	578	632	726	690	851	933	750	895	956	873	970	1,104	1,145	1,293	1,296	1,182	567
Case 36			192	665	703	790	702	1,050	1,280	1,423	1,600	1,700	1,530	1,650	1,650	1,650	1,588	1,390	1,455	1,517
Case 37			122	592	637	736	697	856	1,064	1,245	1,388	206	60	63	81	76	109	124	645	662
Case 38			193	678	765	873	841	939	1,010	1,346	1,483	1,544	1,568	1,588	1,588	1,588	1,505	1,588	1,588	1,588
Case 39			156	596	617	713	668	739	817	626	770	830	738	770	788	788	788	788	850	788
Case 40			199	688	785	899	874	939	1,017	1,363	1,499	1,563	1,188	1,238	1,238	1,238	1,188	1,249	1,445	1,372
Case 41		91	440	931	937	1,037	983	933	1,018	1,387	1,523	1,584	1,552	1,563	1,563	1,485	1,563	1,563	1,563	1,634
Case 42		91	437	913	932	1,017	968	918	1,002	1,362	1,497	1,556	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563
Case 43		50	352	830	842	932	892	933	992	1,311	1,454	1,521	1,436	1,399	1,337	1,071	575	691	755	763
Case 44			206	696	825	939	886	939	1,011	820	959	958	855	1,130	1,098	1,359	1,511	1,588	1,588	1,588
Case 45			227	713	847	968	976	928	1,019	861	1,004	1,068	943	1,048	1,140	1,188	1,188	1,232	1,372	1,355
Case 46			197	688	663	771	771	939	1,016	1,367	988	1,069	961	1,028	1,130	1,188	1,188	1,267	1,363	1,352
Case 47			205	696	670	784	784	939	1,016	1,367	988	1,053	939	1,020	1,123	1,188	1,188	1,188	1,349	1,346
Case 48			200	687	767	799	766	910	981	1,324	1,464	1,525	1,188	1,196	1,386	1,378	1,588	1,588	1,588	1,402

Table A.13 – Total Gas Capacity Additions for 20 years

Gas

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 02	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 03	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 04	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 05	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 06	3	3	3	1,072	1,072	1,072	1,699	1,699	1,699	2,174	2,174	2,649	2,649	2,649	2,649	2,649	2,649	2,649	2,649	2,649
Case 07	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 08	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 09	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 10	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 11	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 12	3	3	3	811	1,072	1,072	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699
Case 13	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 14	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 15	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 16	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 17	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 18	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 19	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 20	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 21	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 22	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 23	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 24	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 25	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 26	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 27	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 28	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 29	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 30	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 31	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 33	3	3	3	811	811	811	811	1,388	1,388	1,388	1,388	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911
Case 34	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 35	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 36	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 37	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 38	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 39	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 40	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 41	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 42	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 43	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 44	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 45	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 46	3	3	3	811	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985
Case 47	3	3	3	811	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985
Case 48	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811

Table A.14 – Total Conventional Coal Capacity Additions for 20 years

Conventional Coal

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 02	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 03	0	53	95	131	145	159	159	167	167	957	957	957	957	957	957	957	957	957	957	957
Case 04	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 05	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 06	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 07	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 08	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 09	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 10	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 11	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 12	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 13	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 14	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 15	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 16	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 17	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 18	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 19	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 20	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 21	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 22	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 23	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 24	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 25	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 26	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 27	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 28	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 29	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 30	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 31	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 33	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 34	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 35	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 36	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 37	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 38	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 39	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 40	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 41	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 42	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 43	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 44	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 45	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 46	0	53	95	131	145	159	159	167	167	167	767	767	767	767	767	767	767	767	767	767
Case 47	0	53	95	131	145	159	159	167	167	167	767	767	767	767	767	767	767	767	767	767
Case 48	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167

Table A.15 – Total Clean Coal Capacity Additions for 20 years

Clean Coal

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346
Case 05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346
Case 06	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 07	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346
Case 08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 09	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346
Case 10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	466	466	466	466
Case 15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	466	466	466	466
Case 16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,342	1,342	1,342	1,342
Case 30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,342	1,342	1,342	1,342
Case 31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 36	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876	876	876	876	876	876
Case 37	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876	876	876	876	876	876
Case 38	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	611	611	876	876
Case 41	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 44	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 45	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 46	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table A.16 – Total Demand-side Management Capacity Additions for 20 years

Demand Side Management

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	34	128	240	345	444	539	711	839	937	1,029	1,111	1,193	1,270	1,348	1,428	1,507	1,588	1,676	1,765	1,850
Case 02	103	240	368	488	591	693	795	894	1,000	1,097	1,184	1,271	1,361	1,453	1,546	1,639	1,731	1,826	1,925	2,022
Case 03	112	261	398	526	635	747	859	971	1,085	1,194	1,290	1,387	1,485	1,584	1,685	1,801	1,909	2,007	2,107	2,204
Case 04	97	233	361	481	582	684	787	886	991	1,087	1,174	1,261	1,351	1,443	1,536	1,629	1,721	1,816	1,912	2,006
Case 05	101	238	365	485	591	694	799	904	1,011	1,108	1,195	1,282	1,372	1,464	1,557	1,650	1,750	1,847	1,945	2,042
Case 06	105	246	377	504	612	850	962	1,074	1,187	1,287	1,383	1,478	1,575	1,675	1,776	1,892	1,999	2,105	2,209	2,313
Case 07	105	246	377	500	605	710	815	920	1,027	1,125	1,213	1,301	1,396	1,493	1,586	1,680	1,773	1,869	1,965	2,062
Case 08	106	248	379	503	613	723	834	951	1,064	1,167	1,263	1,357	1,453	1,550	1,650	1,755	1,857	1,956	2,056	2,154
Case 09	101	238	366	486	589	693	798	902	1,009	1,106	1,193	1,281	1,371	1,462	1,555	1,649	1,749	1,845	1,944	2,041
Case 10	103	244	375	499	605	716	828	945	1,058	1,161	1,257	1,352	1,447	1,544	1,644	1,750	1,851	1,950	2,050	2,148
Case 11	111	260	397	526	639	754	868	982	1,097	1,213	1,310	1,407	1,506	1,607	1,708	1,825	1,933	2,038	2,138	2,236
Case 12	111	258	395	531	643	840	953	1,084	1,198	1,306	1,404	1,506	1,628	1,733	1,841	1,974	2,083	2,195	2,307	2,412
Case 13	112	261	399	530	644	758	872	986	1,100	1,209	1,306	1,404	1,503	1,603	1,705	1,822	1,929	2,035	2,139	2,243
Case 14	115	269	407	540	654	769	883	998	1,114	1,230	1,328	1,426	1,531	1,637	1,739	1,856	1,964	2,071	2,175	2,278
Case 15	120	278	424	563	690	819	948	1,161	1,284	1,398	1,501	1,616	1,722	1,829	1,937	2,070	2,179	2,285	2,389	2,493
Case 16	106	248	380	508	617	729	840	951	1,065	1,167	1,263	1,358	1,454	1,554	1,656	1,772	1,880	1,987	2,091	2,195
Case 17	107	254	391	520	630	742	854	967	1,089	1,197	1,295	1,392	1,491	1,591	1,693	1,810	1,918	2,024	2,128	2,232
Case 18	103	244	376	499	609	721	833	944	1,064	1,166	1,262	1,357	1,452	1,550	1,651	1,767	1,874	1,980	2,083	2,186
Case 19	106	248	384	512	623	735	847	958	1,079	1,187	1,284	1,382	1,481	1,581	1,682	1,799	1,907	2,014	2,118	2,221
Case 20	112	261	398	531	645	760	875	988	1,110	1,219	1,316	1,414	1,513	1,613	1,714	1,831	1,939	2,045	2,149	2,247
Case 21	115	269	407	539	653	768	883	997	1,113	1,222	1,320	1,418	1,517	1,618	1,720	1,837	1,946	2,053	2,157	2,263
Case 22	115	269	407	540	655	775	897	1,017	1,140	1,260	1,363	1,465	1,570	1,676	1,784	1,901	2,010	2,117	2,221	2,327
Case 23	112	261	398	531	645	759	873	987	1,102	1,210	1,308	1,406	1,505	1,606	1,708	1,825	1,933	2,040	2,145	2,250
Case 24	112	261	399	532	647	762	876	990	1,105	1,221	1,323	1,426	1,531	1,637	1,745	1,863	1,971	2,078	2,183	2,288
Case 25	107	255	392	524	638	753	868	981	1,104	1,212	1,309	1,407	1,506	1,606	1,708	1,824	1,932	2,039	2,143	2,247
Case 26	112	261	398	531	645	760	875	988	1,111	1,219	1,316	1,414	1,513	1,613	1,714	1,831	1,939	2,046	2,150	2,254
Case 27	112	266	404	537	651	771	893	1,012	1,136	1,257	1,360	1,464	1,569	1,676	1,784	1,901	2,008	2,114	2,213	2,310
Case 28	115	269	407	540	654	769	884	998	1,114	1,222	1,321	1,419	1,518	1,619	1,721	1,838	1,941	2,040	2,141	2,241
Case 29	116	275	421	560	681	802	925	1,045	1,274	1,394	1,497	1,600	1,706	1,813	1,923	2,057	2,167	2,279	2,391	2,498
Case 30	111	260	398	527	642	757	871	985	1,106	1,215	1,313	1,416	1,521	1,627	1,735	1,869	1,977	2,084	2,196	2,303
Case 31	116	270	416	554	674	795	918	1,039	1,162	1,284	1,387	1,490	1,596	1,703	1,813	1,947	2,057	2,164	2,268	2,371
Case 33	121	281	427	610	735	884	1,065	1,190	1,324	1,444	1,556	1,666	1,778	1,893	2,009	2,147	2,271	2,392	2,513	2,624
Case 34	106	247	379	502	607	718	828	946	1,060	1,162	1,258	1,353	1,448	1,546	1,646	1,751	1,853	1,951	2,051	2,149
Case 35	115	269	407	540	654	768	883	996	1,112	1,227	1,324	1,421	1,520	1,620	1,721	1,837	1,939	2,037	2,137	2,234
Case 36	111	259	397	527	642	756	871	985	1,106	1,214	1,316	1,521	1,620	1,720	1,822	1,939	2,046	2,153	2,257	2,361
Case 37	115	269	407	540	654	770	885	999	1,115	1,231	1,329	1,427	1,527	1,628	1,730	1,847	1,956	2,063	2,167	2,273
Case 38	107	248	384	512	623	734	846	1,021	1,135	1,237	1,334	1,428	1,524	1,621	1,721	1,826	1,928	2,034	2,137	2,240
Case 39	115	269	408	541	655	771	885	1,109	1,225	1,334	1,432	1,530	1,634	1,740	1,848	1,982	2,093	2,206	2,319	2,426
Case 40	105	246	376	499	604	710	816	1,024	1,131	1,229	1,316	1,403	1,493	1,590	1,688	1,792	1,893	1,991	2,090	2,188
Case 41	106	248	379	506	618	729	854	968	1,081	1,183	1,280	1,374	1,470	1,567	1,667	1,772	1,874	1,972	2,072	2,171
Case 42	106	254	391	520	629	740	852	965	1,079	1,188	1,285	1,382	1,481	1,581	1,683	1,800	1,908	2,014	2,118	2,222
Case 43	115	269	407	540	654	774	896	1,121	1,236	1,346	1,448	1,551	1,656	1,762	1,870	1,988	2,096	2,203	2,308	2,413
Case 44	102	239	367	487	590	695	800	1,013	1,118	1,213	1,298	1,383	1,472	1,562	1,655	1,748	1,840	1,935	2,031	2,125
Case 45	97	229	356	475	578	680	782	882	987	1,084	1,170	1,258	1,348	1,439	1,532	1,626	1,717	1,813	1,908	2,002
Case 46	103	240	368	489	591	696	802	926	1,033	1,131	1,218	1,305	1,395	1,487	1,580	1,673	1,765	1,860	1,956	2,050
Case 47	102	239	367	488	591	695	801	933	1,040	1,137	1,223	1,311	1,401	1,493	1,585	1,679	1,771	1,866	1,962	2,055
Case 48	114	261	395	518	628	811	921	1,055	1,168	1,271	1,367	1,461	1,557	1,654	1,754	1,859	1,961	2,060	2,160	2,258

Table A.17 – Total Other Capacity Additions for 20 years

Other

(Capacity MW) (Other includes Distributed Generation, Other Renewables, and Nuclear)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	13	27	40	79	117	156	169	183	191	199	205	205	205	205	205	205	205	205	205	205
Case 02	8	17	25	58	126	159	167	176	184	194	196	199	202	205	207	210	213	215	218	219
Case 03	8	17	31	64	202	241	274	308	316	324	324	324	324	324	324	324	324	324	324	324
Case 04	8	17	25	58	126	159	170	180	190	201	203	206	209	211	214	217	217	218	219	219
Case 05	8	17	25	58	126	161	172	183	194	205	208	210	213	216	218	219	219	219	219	219
Case 06	14	29	43	83	174	289	330	401	412	422	424	426	434	435	437	438	438	438	438	438
Case 07	8	17	25	58	126	159	194	204	240	251	253	256	259	262	264	267	268	269	269	269
Case 08	10	23	37	82	156	196	243	319	330	341	344	346	349	351	353	354	354	354	354	354
Case 09	8	17	25	58	126	160	171	182	193	204	207	210	212	215	217	219	219	219	219	219
Case 10	8	17	25	60	129	163	213	324	335	346	349	352	354	355	357	358	358	358	358	358
Case 11	8	17	25	64	202	241	277	312	322	333	335	337	339	341	343	343	343	343	343	343
Case 12	13	27	41	87	231	270	318	359	370	381	384	391	394	395	397	398	398	803	1,188	1,203
Case 13	8	17	31	70	208	241	274	308	316	324	324	324	324	324	324	324	324	324	324	324
Case 14	8	17	37	71	209	243	279	315	326	337	340	342	345	347	349	349	349	349	349	349
Case 15	14	28	55	94	239	528	819	861	872	883	885	892	894	895	897	898	2,498	2,498	2,498	2,498
Case 16	8	17	25	71	210	244	280	316	327	338	341	343	346	348	350	351	351	351	351	351
Case 17	8	17	25	72	211	245	281	317	328	339	342	345	347	348	350	351	351	351	351	351
Case 18	8	17	26	72	176	246	282	318	329	340	342	345	347	348	350	351	351	351	351	351
Case 19	8	17	26	72	211	246	282	318	329	340	342	345	347	348	350	351	351	351	351	351
Case 20	8	17	25	70	208	242	277	312	323	333	335	337	339	342	344	344	1,944	1,944	1,944	1,944
Case 21	8	17	31	70	208	241	274	308	316	324	324	324	324	324	324	324	1,924	1,924	1,924	1,924
Case 22	8	17	31	70	208	242	278	313	322	331	331	331	331	331	331	331	1,931	1,931	1,931	1,931
Case 23	8	17	27	73	212	246	282	318	329	340	343	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 24	9	18	28	74	213	248	284	320	331	341	344	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 25	9	18	28	74	213	248	283	319	330	341	344	345	347	348	350	351	351	351	351	351
Case 26	9	18	28	74	213	248	283	319	330	341	344	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 27	8	17	26	72	211	246	282	318	329	340	342	345	347	348	350	350	3,550	3,550	3,550	3,550
Case 28	8	17	31	70	208	241	274	308	316	324	324	324	324	324	324	324	3,524	3,524	3,524	3,524
Case 29	9	23	43	89	233	272	314	355	371	387	389	391	394	395	397	397	3,597	3,597	3,597	3,597
Case 30	8	17	25	60	135	210	246	317	328	339	342	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 31	9	18	39	73	211	246	282	318	329	340	342	344	346	348	350	351	3,551	3,551	3,551	3,551
Case 33	14	28	49	94	489	778	819	861	877	888	890	891	894	895	897	898	898	1,303	1,688	1,688
Case 34	8	17	29	74	147	187	234	275	286	297	300	303	306	308	310	311	311	311	311	311
Case 35	9	18	39	72	175	208	241	275	283	291	291	291	291	291	291	291	291	291	291	291
Case 36	8	17	31	83	192	232	268	309	325	341	349	357	359	360	362	363	363	363	363	363
Case 37	8	17	31	70	173	206	239	273	281	289	289	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489
Case 38	13	27	40	80	154	194	235	276	287	298	300	303	306	308	309	311	311	311	311	311
Case 39	13	27	46	85	193	237	276	314	328	336	336	336	336	336	336	336	336	338	341	344
Case 40	13	27	40	79	152	190	229	267	276	284	284	284	284	284	284	284	284	284	284	284
Case 41	13	27	41	87	231	276	318	359	370	381	384	386	388	390	391	393	393	393	393	393
Case 42	8	17	25	72	211	245	281	317	328	339	342	345	347	348	350	351	351	351	351	351
Case 43	15	29	44	96	240	279	321	362	373	384	385	387	388	390	391	393	3,593	3,593	3,593	3,593
Case 44	13	27	40	79	118	158	233	274	283	291	291	328	330	332	334	336	373	376	378	379
Case 45	6	13	21	54	88	121	131	176	187	198	203	207	210	213	250	253	279	304	304	305
Case 46	13	27	40	79	118	158	174	190	200	211	213	216	219	222	224	226	226	226	226	226
Case 47	13	27	40	79	118	158	174	190	200	211	213	216	219	222	224	226	226	226	226	226
Case 48	8	17	25	64	132	167	203	239	256	267	270	272	275	278	280	281	281	281	281	281

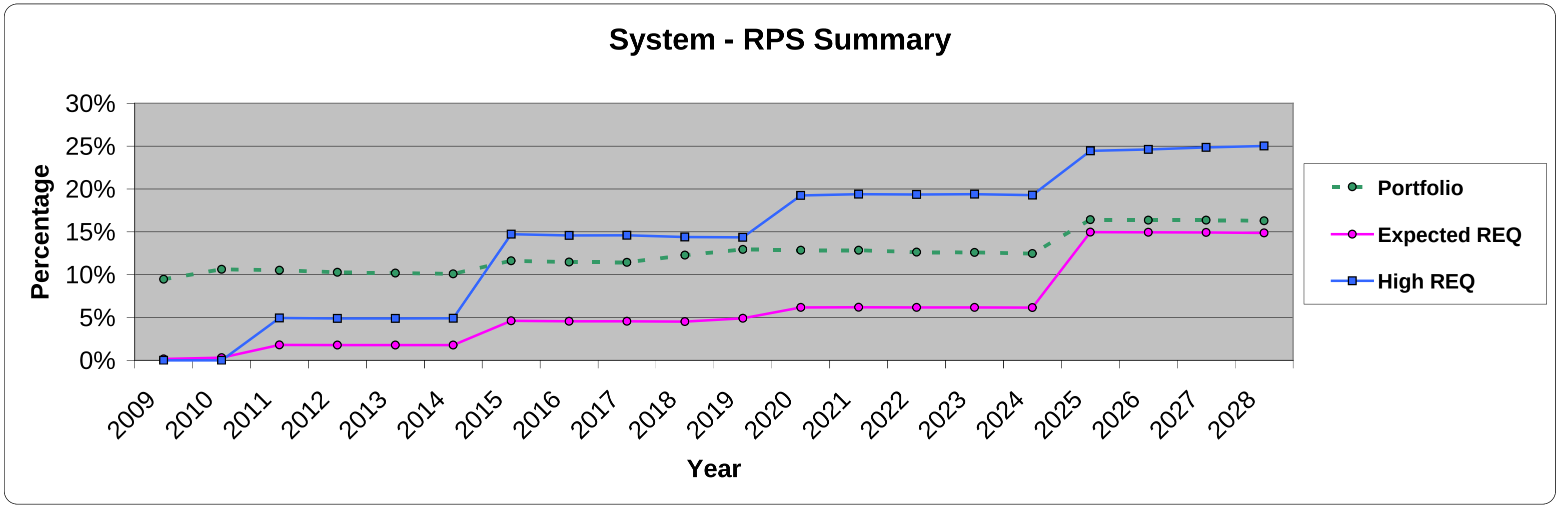
DETAILED PORTFOLIO DATA

Renewable Portfolio Summary by Case

For each case, PacifiCorp generated an RPS compliance report. This report shows the annual system RPS requirements, REC bank balances, REC-adjusted qualifying generation, RPS compliance percentages, and the system load used in the calculations. The report also includes a line chart comparing the RPS compliance and system generation requirements percentages for both the base and high RPS scenarios (Expected REQ and High REQ, respectively). See Chapter 7 “Representation and Modeling of Renewable Portfolio Standards” for additional information.

System - RPS Report - Case # 1

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,131	18,404	21,743	25,007	28,225	31,466	34,074	35,843	37,610	39,340	40,915	42,474	43,948	39,329	34,645	29,878	25,051
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	340	345	357	118	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	1,376	2,519	2,952	3,376	3,782	4,166	2,986	1,794	581	-	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,534**	**15,343**	**18,847**	**22,531**	**26,266**	**28,111**	**30,019**	**32,048**	**34,074**	**35,843**	**37,610**	**39,340**	**40,915**	**42,474**	**43,948**	**39,329**	**34,645**	**29,878**	**25,051**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,205	3,211	3,273	3,340	3,264	3,281	3,306	3,314	3,334	3,357	3,370	3,321	3,337	3,342	5,257	5,301	5,358	5,391
Other (ID,WY)	822	1,022	1,034	1,046	1,052	1,071	1,018	1,029	1,038	1,035	1,038	1,041	1,042	1,010	1,013	983	991	996	1,003	1,009
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	290	299	303	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	982	1,143	1,133	1,132	1,126	1,116	2,228	2,244	2,266	2,918	3,163	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,107**	**5,807**	**5,850**	**5,873**	**5,953**	**6,043**	**7,104**	**7,160**	**7,229**	**7,897**	**8,430**	**8,465**	**8,525**	**8,469**	**8,524**	**8,534**	**11,317**	**11,396**	**11,503**	**11,586**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	10%	10%	12%	11%	11%	12%	13%	13%	13%	13%	13%	12%	16%	16%	16%	16%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

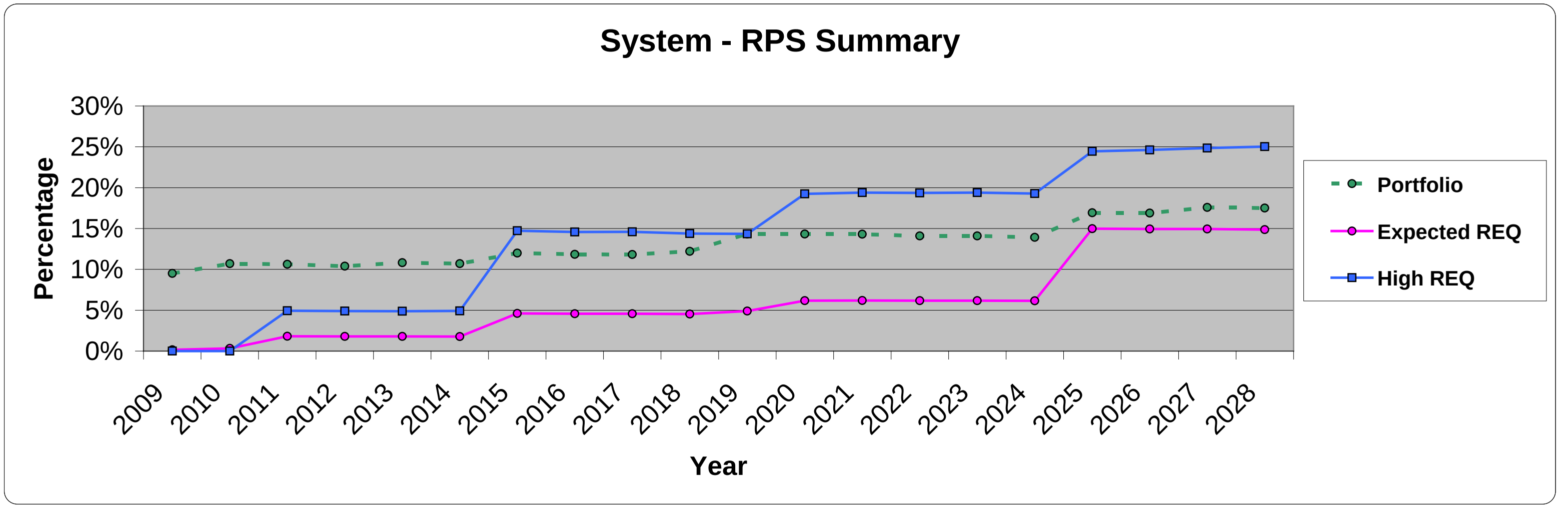


Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded

System - RPS Report - Case # 2

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,743	11,975	15,216	18,646	22,145	25,557	28,947	32,369	36,054	38,983	42,216	45,419	48,470	51,548	54,519	51,372	48,147	46,782	45,340
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	350	380	415	174	-	-	2	-	-	-	-	-	-	-	-	-	-
Oregon	1,382	2,536	2,985	3,428	3,928	4,407	3,315	2,209	1,086	82	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,941**	**11,583**	**15,439**	**18,994**	**22,954**	**26,967**	**29,047**	**31,156**	**33,455**	**36,139**	**38,983**	**42,216**	**45,419**	**48,470**	**51,548**	**54,519**	**51,372**	**48,147**	**46,782**	**45,340**
Adjusted Qualifying Renewables																				
Utah	2,959	3,184	3,231	3,241	3,430	3,499	3,412	3,427	3,459	3,685	3,942	3,971	3,987	3,939	3,974	3,969	5,257	5,301	5,358	5,391
Other (ID,WY)	828	1,032	1,049	1,063	1,141	1,162	1,103	1,113	1,126	1,249	1,389	1,398	1,402	1,371	1,386	1,349	1,355	1,361	1,861	1,872
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	328	332	370	372	375	379	632	636	640	644	647	651	655	659	662	666
Oregon	988	1,155	1,149	1,150	1,220	1,211	2,228	2,244	2,266	2,277	3,106	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,129**	**5,850**	**5,912**	**5,945**	**6,322**	**6,417**	**7,337**	**7,389**	**7,469**	**7,843**	**9,331**	**9,437**	**9,502**	**9,448**	**9,534**	**9,527**	**11,681**	**11,761**	**12,361**	**12,449**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	11%	11%	12%	12%	12%	12%	14%	14%	14%	14%	14%	14%	17%	17%	18%	17%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

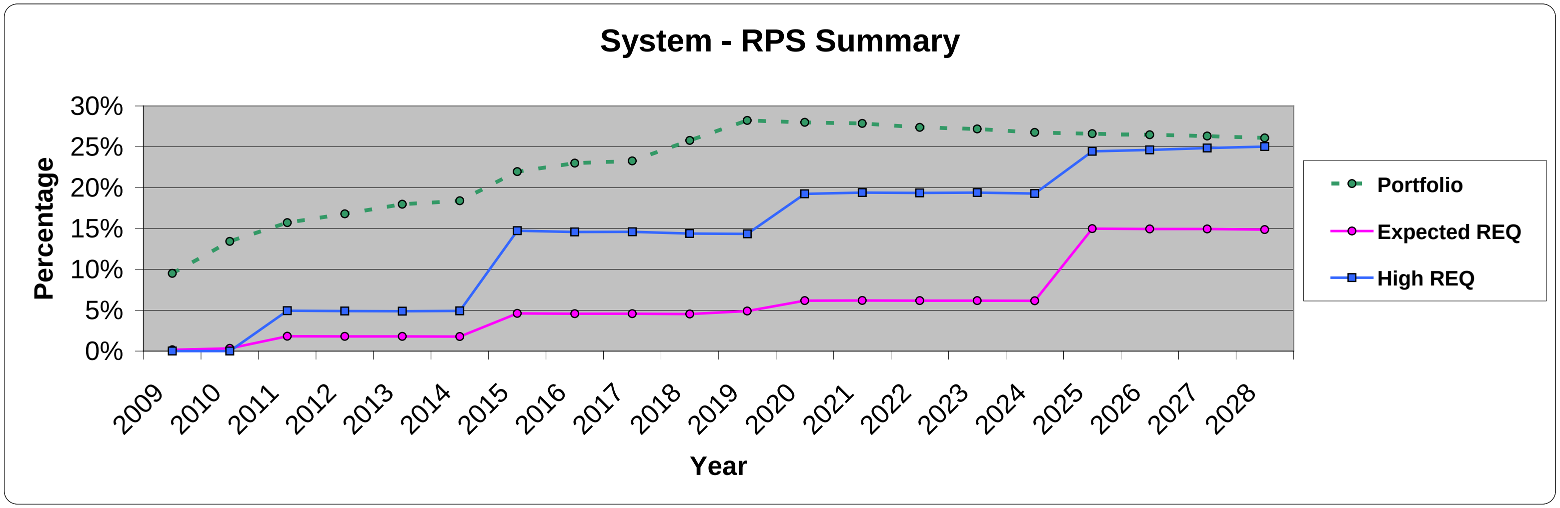

System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded

System - RPS Report - Case # 3

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,377	13,818	18,615	23,830	29,290	35,777	42,658	49,694	57,515	66,116	74,739	83,394	91,990	100,611	109,224	112,576	115,904	119,184	122,434
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	419	816	855	990	1,099	1,093	1,120	1,210	1,373	1,398	1,274	1,264	1,247	1,231	1,224	1,204	1,180	1,159	1,136
Oregon	1,382	2,926	4,110	5,493	7,067	8,711	9,436	10,362	11,338	12,766	14,613	15,629	16,604	17,516	18,394	19,221	19,137	18,978	18,730	18,388
Cumulative Surplus Credit Bank Balance	**6,942**	**12,721**	**18,744**	**24,963**	**31,887**	**39,099**	**46,306**	**54,140**	**62,242**	**71,655**	**82,126**	**91,642**	**101,261**	**110,752**	**120,236**	**129,670**	**132,917**	**136,062**	**139,074**	**141,958**
Adjusted Qualifying Renewables																				
Utah	2,960	3,817	4,441	4,797	5,215	5,460	6,487	6,881	7,037	7,821	8,600	8,624	8,654	8,596	8,621	8,613	8,609	8,629	8,638	8,640
Other (ID,WY)	828	1,380	1,721	1,932	2,144	2,279	2,867	3,102	3,193	3,633	4,078	4,105	4,125	4,091	4,107	4,059	4,081	4,115	4,142	4,164
California	88	176	185	194	204	213	223	233	243	269	300	336	339	341	345	348	352	354	357	360
Washington	266	419	519	580	654	690	896	966	991	1,134	1,272	1,269	1,271	1,260	1,261	1,260	1,250	1,244	1,237	1,228
Oregon	989	1,543	1,885	2,091	2,294	2,376	2,953	3,170	3,242	3,706	4,146	4,112	4,108	4,066	4,061	4,038	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**7,335**	**8,750**	**9,593**	**10,511**	**11,018**	**13,427**	**14,353**	**14,706**	**16,563**	**18,396**	**18,445**	**18,497**	**18,354**	**18,395**	**18,318**	**18,353**	**18,428**	**18,496**	**18,552**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	17%	18%	18%	22%	23%	23%	26%	28%	28%	28%	27%	27%	27%	27%	26%	26%	26%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

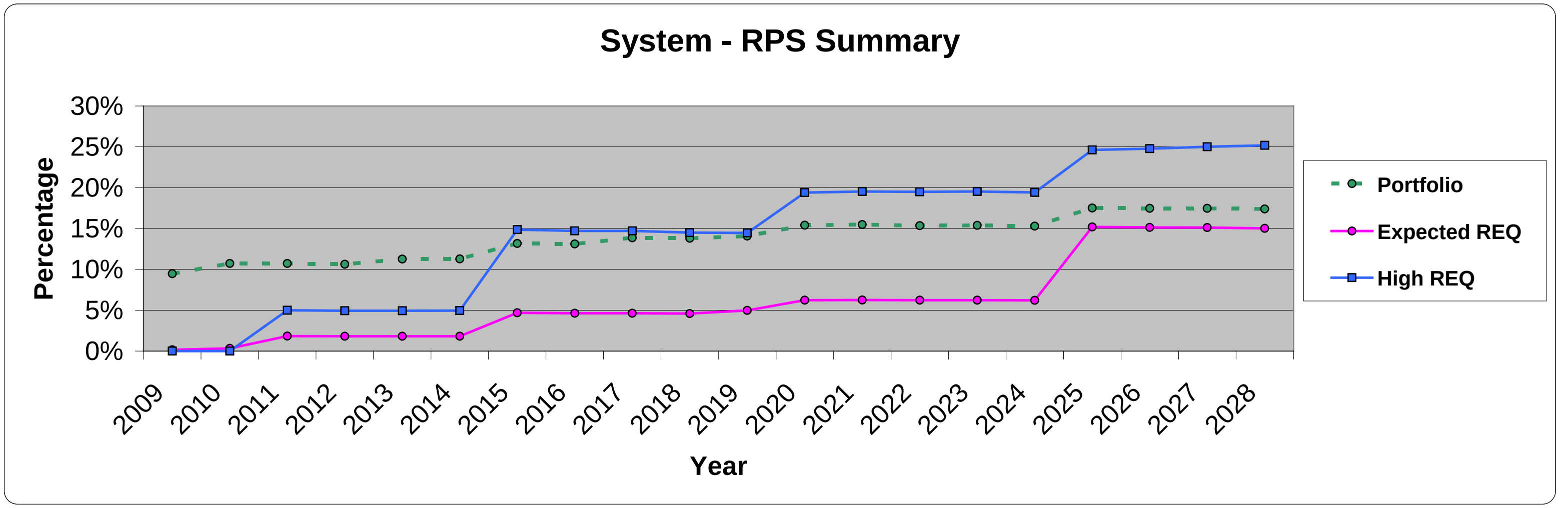


Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 4

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,550	8,715	11,919	15,138	18,571	22,075	25,704	29,360	33,272	37,195	41,062	44,887	48,563	52,128	55,719	59,250	57,591	55,984	54,409	52,888
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	472	344	381	424	235	47	96	144	-	-	-	-	-	-	-	-	-	-
Oregon	1,376	2,519	2,958	3,402	3,926	4,437	3,587	2,753	2,057	1,382	710	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,534**	**15,349**	**18,883**	**22,878**	**26,935**	**29,526**	**32,160**	**35,425**	**38,721**	**41,773**	**44,887**	**48,563**	**52,128**	**55,719**	**59,250**	**57,591**	**55,984**	**54,409**	**52,888**
Adjusted Qualifying Renewables																				
Utah	2,950	3,165	3,204	3,219	3,433	3,503	3,629	3,656	3,912	3,923	3,948	3,978	3,993	3,942	3,957	3,952	4,505	4,479	4,464	4,426
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,228	1,245	1,387	1,386	1,392	1,402	1,405	1,372	1,376	1,338	1,345	1,351	1,357	1,363
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	264	300	293	292	328	333	374	377	421	423	577	574	572	568	564	561	558	554	550	546
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Adjusted Qualifying Renewables	**5,108**	**5,806**	**5,848**	**5,891**	**6,330**	**6,426**	**7,568**	**7,616**	**8,063**	**8,071**	**8,262**	**9,033**	**9,050**	**8,946**	**8,952**	**8,898**	**10,141**	**10,095**	**10,068**	**10,019**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	9%	11%	11%	11%	11%	11%	13%	13%	14%	14%	14%	15%	15%	15%	15%	15%	18%	17%	17%	17%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

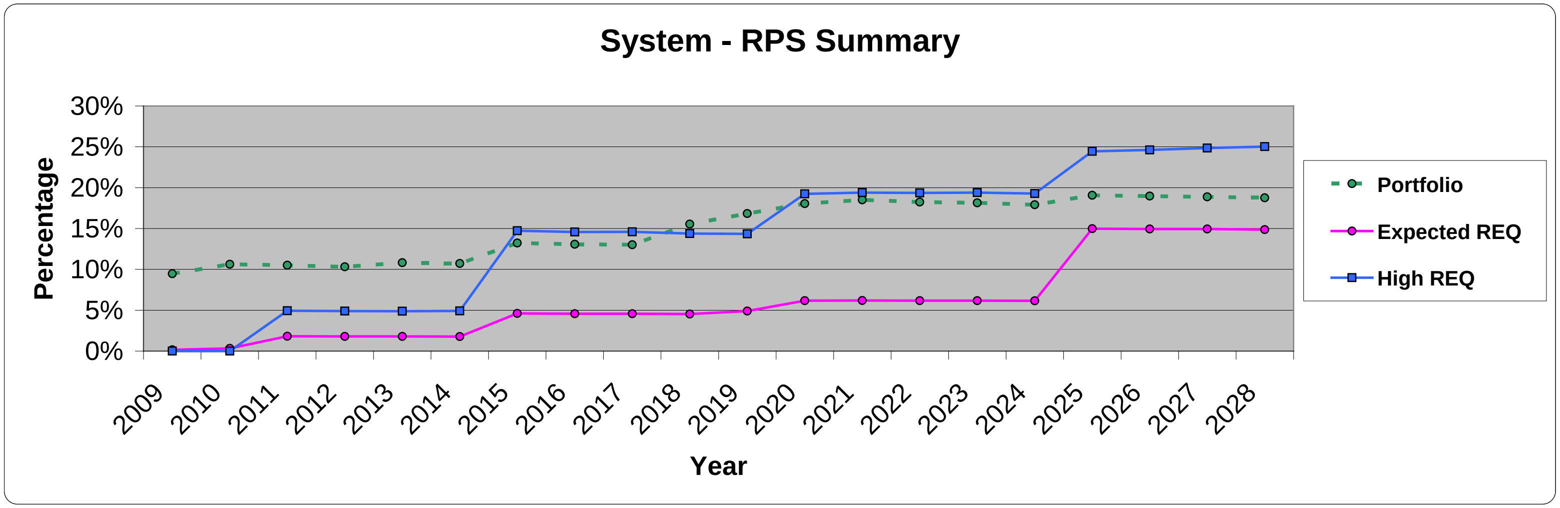


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 5

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,138	18,572	22,075	25,936	29,823	33,735	38,638	44,089	49,570	55,262	60,902	66,558	72,209	72,622	73,013	73,368	73,712
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	93	270	290	125	149	166	149	141	126	107	89	71
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,537	2,702	1,844	1,557	1,555	739	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,860**	**22,831**	**26,856**	**29,730**	**32,619**	**35,671**	**40,465**	**45,934**	**50,434**	**55,411**	**61,068**	**66,707**	**72,350**	**72,748**	**73,120**	**73,457**	**73,783**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	3,861	3,887	3,912	4,903	5,451	5,481	5,692	5,640	5,656	5,651	5,671	5,692	5,713	5,734
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,360	1,378	1,387	1,951	2,260	2,277	2,396	2,365	2,370	2,330	2,347	2,364	2,380	2,396
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	417	420	421	602	697	695	730	720	720	719	713	708	702	697
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,891**	**6,330**	**6,427**	**8,089**	**8,162**	**8,229**	**9,986**	**10,971**	**11,885**	**12,290**	**12,220**	**12,273**	**12,258**	**13,144**	**13,204**	**13,275**	**13,347**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	13%	16%	17%	18%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

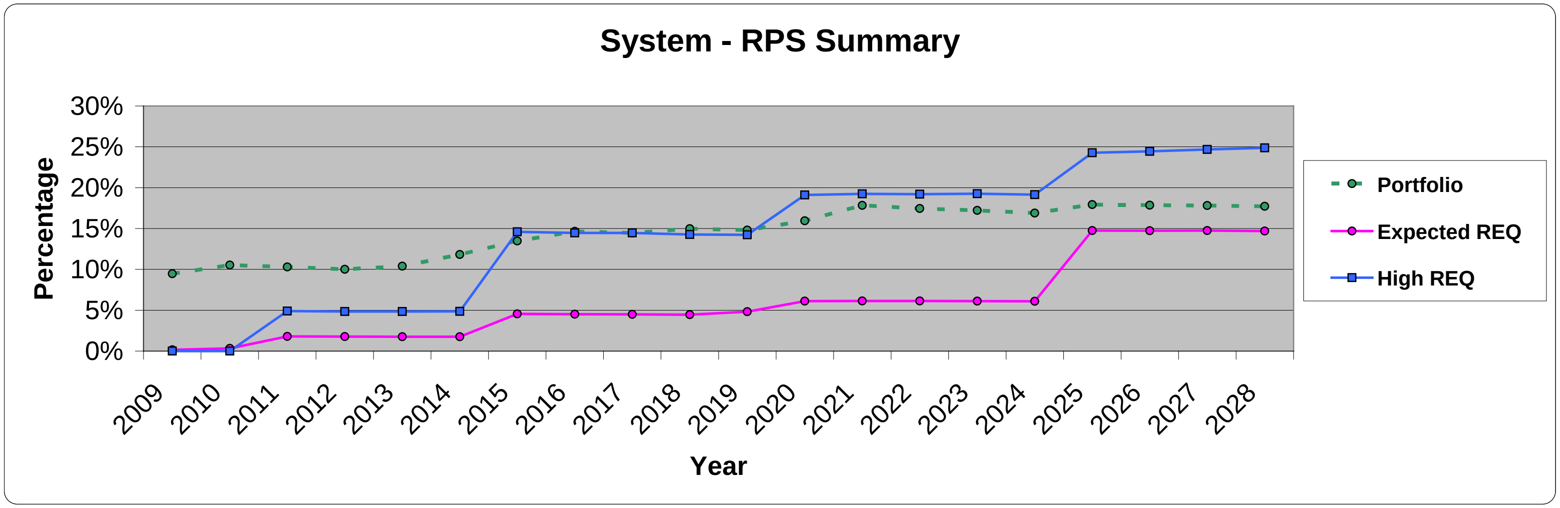


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 6

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,508	26,682	31,430	36,202	41,314	46,451	51,553	57,643	63,683	69,738	75,787	75,755	75,599	75,172	74,493
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	470	339	371	488	371	269	359	408	181	-	87	153	119	93	59	21	-	-
Oregon	1,376	2,519	2,945	3,359	3,839	4,547	3,788	3,314	2,789	2,423	2,006	658	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,335**	**18,836**	**22,783**	**27,542**	**30,841**	**35,013**	**39,350**	**44,146**	**48,638**	**52,211**	**57,731**	**63,836**	**69,856**	**75,880**	**75,814**	**75,619**	**75,172**	**74,493**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,936	4,175	4,748	4,772	5,112	5,137	5,167	6,091	6,040	6,055	6,050	6,103	6,233	6,383	6,509
Other (ID,WY)	823	1,022	1,034	1,050	1,143	1,411	1,540	1,874	1,885	2,071	2,078	2,094	2,629	2,598	2,604	2,563	2,583	2,602	2,621	2,639
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	264	300	293	292	328	412	474	577	578	640	691	703	803	793	793	792	786	781	793	807
Oregon	982	1,143	1,133	1,137	1,222	1,471	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,849**	**5,892**	**6,331**	**7,443**	**8,760**	**9,822**	**9,919**	**10,558**	**10,704**	**11,780**	**13,428**	**13,406**	**13,509**	**13,545**	**14,665**	**14,902**	**15,192**	**15,462**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	9%	11%	10%	10%	10%	12%	13%	15%	14%	15%	15%	16%	18%	17%	17%	17%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

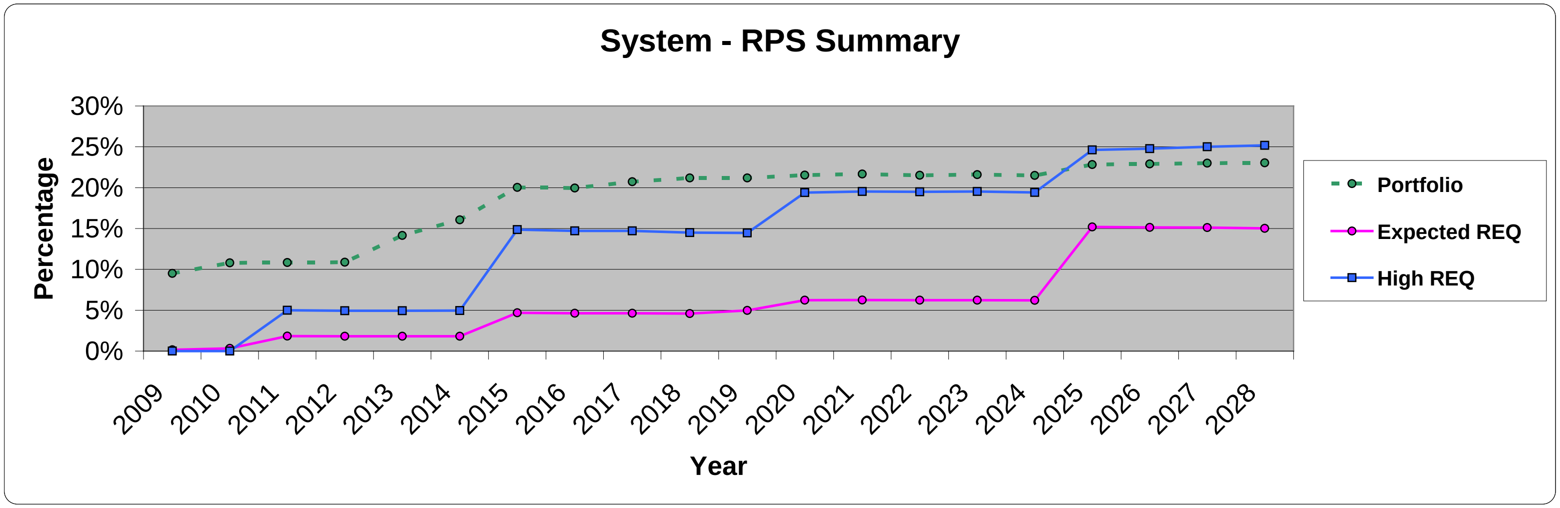


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = High, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 7

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	8,742	11,973	15,249	19,371	24,034	29,708	35,410	41,318	47,369	53,444	59,550	65,670	71,739	77,824	83,903	85,497	87,139	88,817	90,555
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	480	359	517	761	821	794	834	898	697	469	471	467	464	470	470	465	462	459
Oregon	1,382	2,536	2,991	3,469	4,408	5,608	5,966	6,335	6,812	7,387	7,965	7,832	7,690	7,525	7,361	7,181	6,281	5,368	4,435	3,482
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,444**	**19,077**	**24,296**	**30,403**	**36,495**	**42,539**	**48,964**	**55,654**	**62,106**	**67,851**	**73,831**	**79,731**	**85,649**	**91,554**	**92,248**	**92,972**	**93,715**	**94,496**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,276	4,122	4,663	5,674	5,701	5,909	6,051	6,075	6,106	6,120	6,069	6,084	6,079	6,100	6,121	6,142	6,163
Other (ID,WY)	828	1,031	1,049	1,082	1,530	1,825	2,401	2,423	2,541	2,612	2,620	2,640	2,647	2,615	2,621	2,580	2,600	2,620	2,638	2,657
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	266	303	298	302	454	544	748	751	785	811	811	809	808	799	798	797	792	786	781	775
Oregon	989	1,154	1,149	1,171	1,637	1,903	2,473	2,476	2,580	2,665	2,664	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Adjusted Qualifying Renewables	**5,130**	**5,845**	**5,912**	**6,025**	**7,946**	**9,148**	**11,518**	**11,582**	**12,056**	**12,389**	**12,430**	**12,633**	**12,655**	**12,547**	**12,559**	**12,503**	**13,224**	**13,236**	**13,258**	**13,280**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	11%	11%	11%	14%	16%	20%	20%	21%	21%	21%	22%	22%	22%	22%	21%	23%	23%	23%	23%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

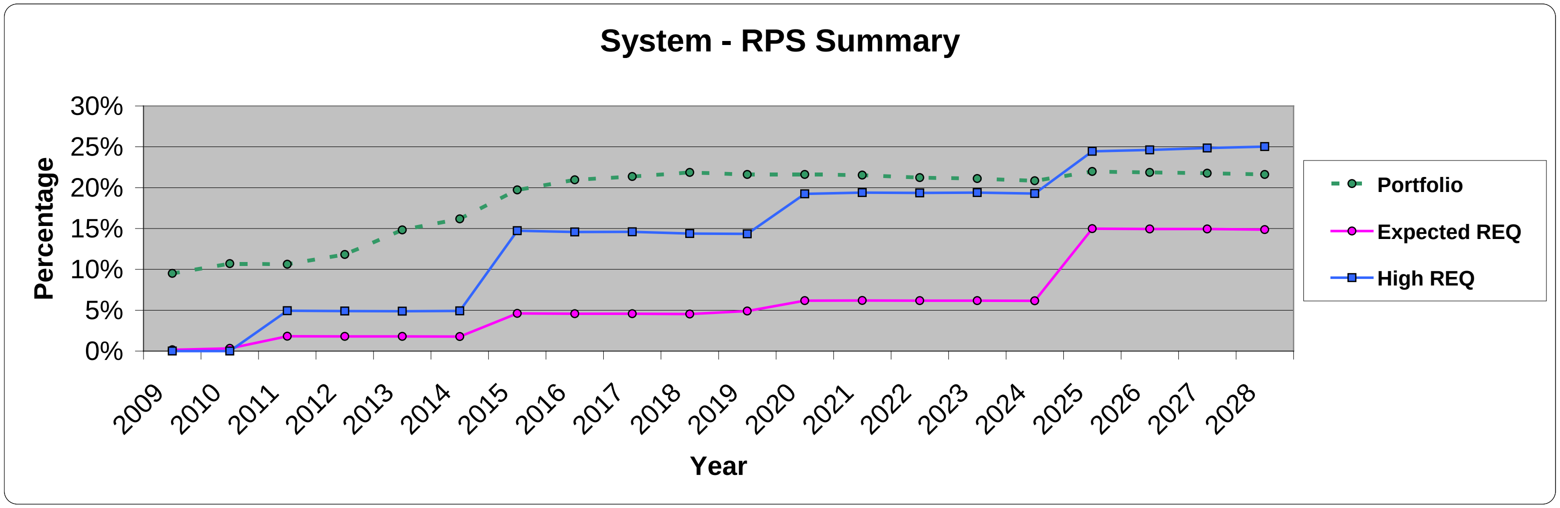


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 8

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,742	11,973	15,559	19,990	24,883	30,787	37,127	43,651	50,409	57,191	64,004	70,831	77,608	84,399	91,185	92,735	94,262	95,752	97,232
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	413	625	852	883	915	1,018	1,086	872	611	599	581	564	556	541	522	504	486
Oregon	1,382	2,536	2,984	3,635	4,738	6,045	6,426	7,033	7,708	8,511	9,291	9,251	9,164	9,020	8,839	8,606	7,484	6,301	5,044	3,715
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,436**	**19,607**	**25,353**	**31,780**	**38,097**	**45,074**	**52,376**	**60,006**	**67,354**	**73,866**	**80,595**	**87,208**	**93,802**	**100,347**	**100,760**	**101,084**	**101,301**	**101,433**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,586	4,431	4,893	5,904	6,339	6,524	6,758	6,782	6,813	6,827	6,776	6,791	6,786	6,807	6,828	6,849	6,870
Other (ID,WY)	828	1,031	1,049	1,255	1,703	1,956	2,533	2,790	2,897	3,020	3,029	3,051	3,059	3,028	3,035	2,993	3,017	3,041	3,064	3,087
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	359	511	586	790	867	898	940	940	938	937	928	927	926	921	915	910	904
Oregon	989	1,154	1,149	1,359	1,823	2,040	2,609	2,851	2,941	3,081	3,079	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**6,752**	**8,672**	**9,689**	**12,059**	**13,081**	**13,503**	**14,052**	**14,093**	**14,234**	**14,296**	**14,227**	**14,281**	**14,264**	**15,158**	**15,224**	**15,303**	**15,382**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	15%	16%	20%	21%	21%	22%	22%	22%	22%	21%	21%	21%	22%	22%	22%	22%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

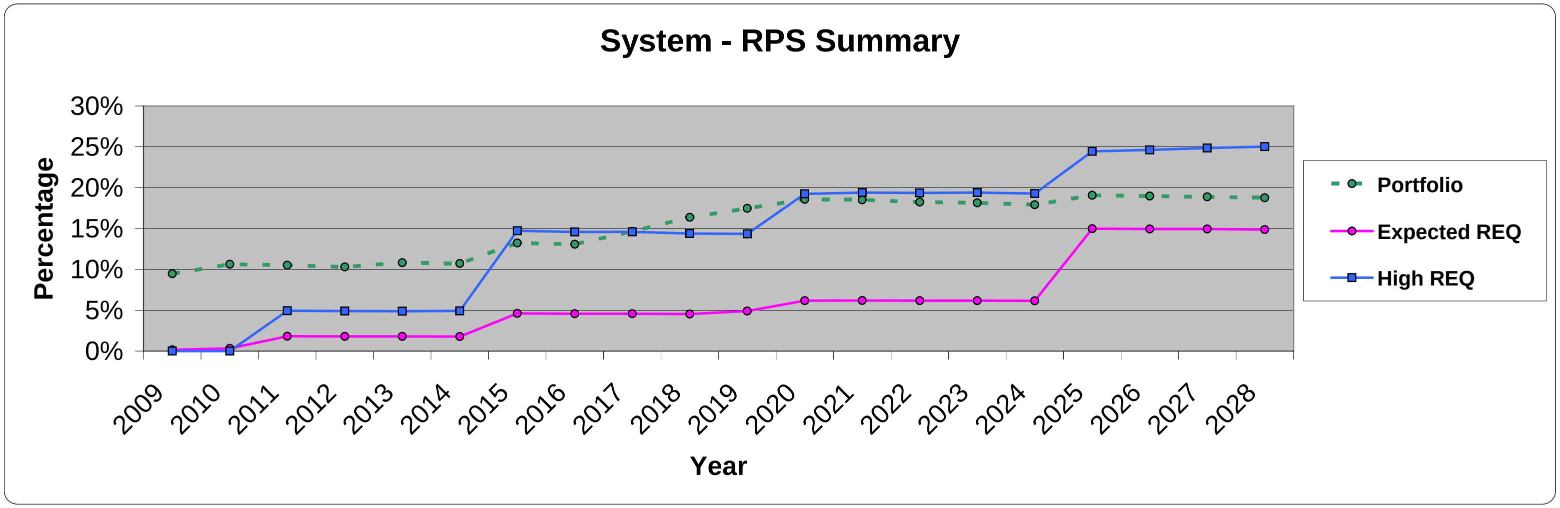


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 9

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,137	18,571	22,074	25,934	29,822	34,314	39,519	45,146	50,823	56,515	62,155	67,811	73,461	73,875	74,266	74,621	74,964
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	199	431	377	193	184	166	149	141	126	107	89	71
Oregon	1,376	2,519	2,952	3,380	3,882	4,363	3,537	2,701	2,184	2,074	2,175	1,474	727	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**18,858**	**22,829**	**26,854**	**29,728**	**32,617**	**36,697**	**42,023**	**47,699**	**52,489**	**57,426**	**62,321**	**67,960**	**73,602**	**74,001**	**74,373**	**74,710**	**75,036**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,217	3,433	3,503	3,861	3,887	4,492	5,205	5,628	5,677	5,692	5,640	5,656	5,651	5,671	5,692	5,713	5,734
Other (ID,WY)	822	1,022	1,034	1,049	1,143	1,164	1,360	1,378	1,723	2,125	2,362	2,390	2,396	2,365	2,370	2,330	2,347	2,364	2,380	2,396
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	291	328	333	417	420	527	657	730	731	730	720	720	719	713	708	702	697
Oregon	982	1,144	1,133	1,136	1,222	1,214	2,228	2,244	2,266	2,277	2,401	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**5,888**	**6,331**	**6,427**	**8,089**	**8,162**	**9,251**	**10,516**	**11,383**	**12,230**	**12,290**	**12,220**	**12,273**	**12,258**	**13,144**	**13,204**	**13,275**	**13,347**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	15%	16%	17%	19%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

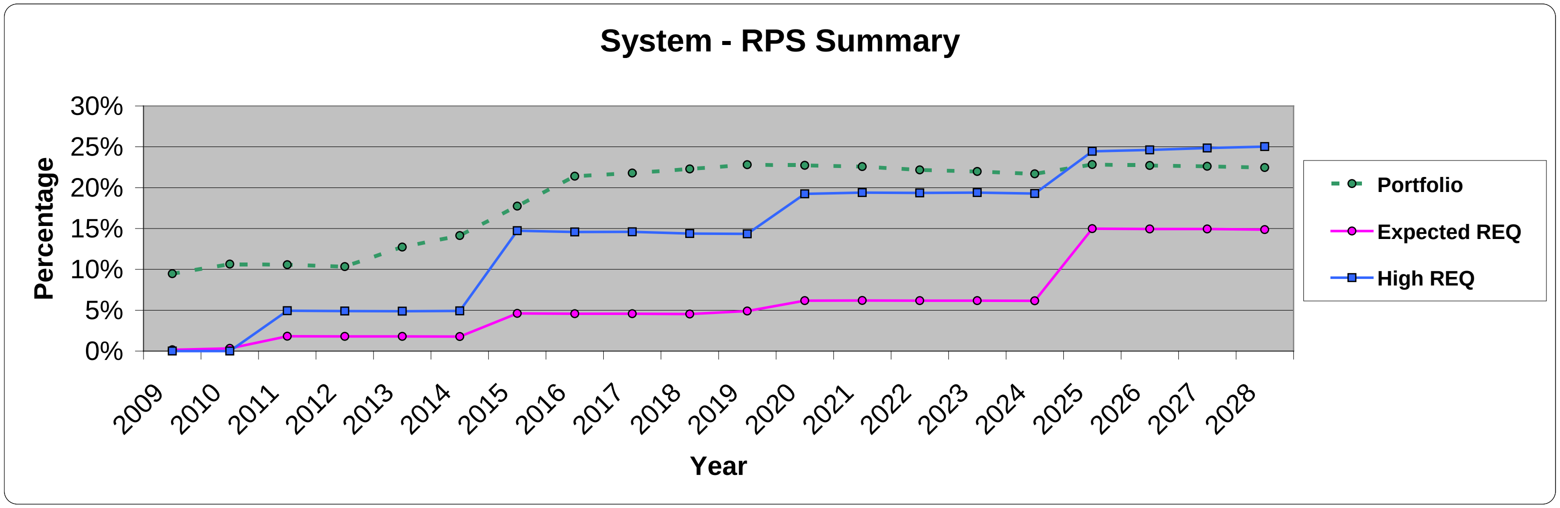


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 10

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,551	8,721	11,942	15,168	19,073	23,448	28,834	35,289	41,929	48,803	55,917	63,061	70,220	77,328	84,451	91,569	93,450	95,308	97,131	98,941
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	475	346	464	662	694	841	1,060	1,128	953	732	720	702	685	677	662	643	625	607
Oregon	1,376	2,522	2,965	3,398	4,185	5,184	5,258	5,934	6,677	7,548	8,522	8,676	8,782	8,830	8,841	8,800	7,869	6,875	5,805	4,661
Cumulative Surplus Credit Bank Balance	**6,927**	**11,544**	**15,381**	**18,912**	**23,722**	**29,293**	**34,786**	**42,064**	**49,666**	**57,479**	**65,392**	**72,469**	**79,722**	**86,860**	**93,977**	**101,046**	**101,981**	**102,826**	**103,561**	**104,209**
Adjusted Qualifying Renewables																				
Utah	2,950	3,170	3,221	3,226	3,906	4,375	5,386	6,455	6,640	6,874	7,114	7,144	7,159	7,108	7,123	7,118	7,138	7,159	7,180	7,202
Other (ID,WY)	823	1,025	1,043	1,054	1,408	1,661	2,235	2,857	2,964	3,087	3,220	3,244	3,253	3,222	3,229	3,187	3,213	3,239	3,264	3,289
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	301	296	293	415	492	695	889	919	961	1,001	999	998	988	988	987	981	976	970	965
Oregon	983	1,146	1,143	1,141	1,506	1,731	2,303	2,920	3,009	3,149	3,274	3,250	3,239	3,202	3,193	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,109**	**5,817**	**5,888**	**5,909**	**7,438**	**8,472**	**10,842**	**13,353**	**13,775**	**14,323**	**14,872**	**14,972**	**14,988**	**14,861**	**14,878**	**14,850**	**15,745**	**15,814**	**15,894**	**15,975**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	13%	14%	18%	21%	22%	22%	23%	23%	23%	22%	22%	22%	23%	23%	23%	22%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

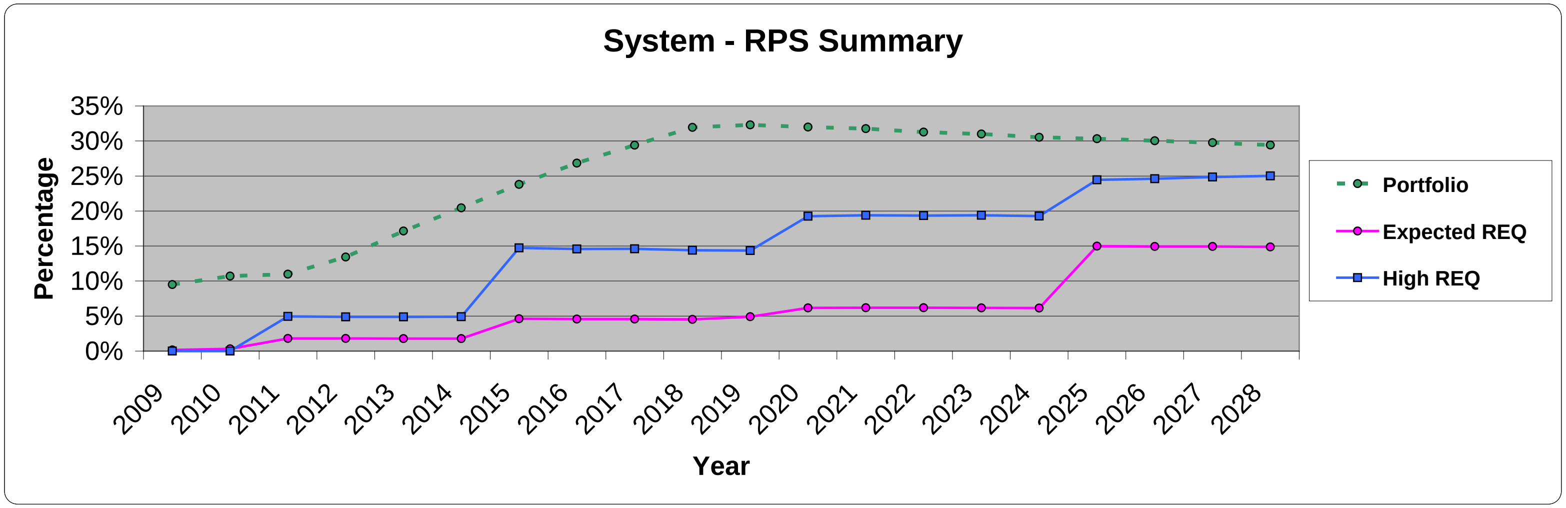


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 11

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,556	8,739	12,055	16,033	21,039	27,026	33,987	41,869	50,530	60,015	69,725	79,466	89,221	98,925	108,645	118,359	122,836	127,291	131,710	136,117
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	495	500	802	1,157	1,276	1,389	1,689	1,974	1,904	1,680	1,669	1,650	1,634	1,625	1,611	1,591	1,573	1,555
Oregon	1,380	2,534	3,034	3,922	5,370	7,328	8,333	9,848	11,776	14,183	16,681	18,348	19,963	21,518	23,032	24,499	25,061	25,544	25,937	26,241
Cumulative Surplus Credit Bank Balance	**6,936**	**11,576**	**15,584**	**20,455**	**27,211**	**35,511**	**43,596**	**53,106**	**63,995**	**76,172**	**88,310**	**99,494**	**110,852**	**122,094**	**133,310**	**144,483**	**149,508**	**154,426**	**159,220**	**163,913**
Adjusted Qualifying Renewables																				
Utah	2,956	3,183	3,316	3,978	5,006	5,987	6,961	7,882	8,661	9,485	9,710	9,741	9,755	9,704	9,719	9,714	9,735	9,756	9,777	9,798
Other (ID,WY)	826	1,032	1,096	1,474	2,027	2,580	3,139	3,679	4,132	4,592	4,719	4,755	4,768	4,738	4,750	4,702	4,745	4,787	4,828	4,869
California	88	176	185	194	204	213	236	273	303	336	344	341	341	341	345	348	352	354	357	360
Washington	265	303	313	430	616	786	983	1,149	1,288	1,438	1,475	1,473	1,472	1,462	1,462	1,461	1,455	1,450	1,444	1,439
Oregon	986	1,154	1,201	1,596	2,168	2,690	3,233	3,759	4,195	4,685	4,798	4,763	4,748	4,709	4,696	4,678	4,623	4,569	4,516	4,463
Adjusted Qualifying Renewables	**5,122**	**5,848**	**6,110**	**7,671**	**10,020**	**12,256**	**14,552**	**16,742**	**18,578**	**20,535**	**21,047**	**21,072**	**21,084**	**20,955**	**20,972**	**20,903**	**20,910**	**20,915**	**20,922**	**20,929**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	20%	24%	27%	29%	32%	32%	32%	32%	31%	31%	31%	30%	30%	30%	29%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

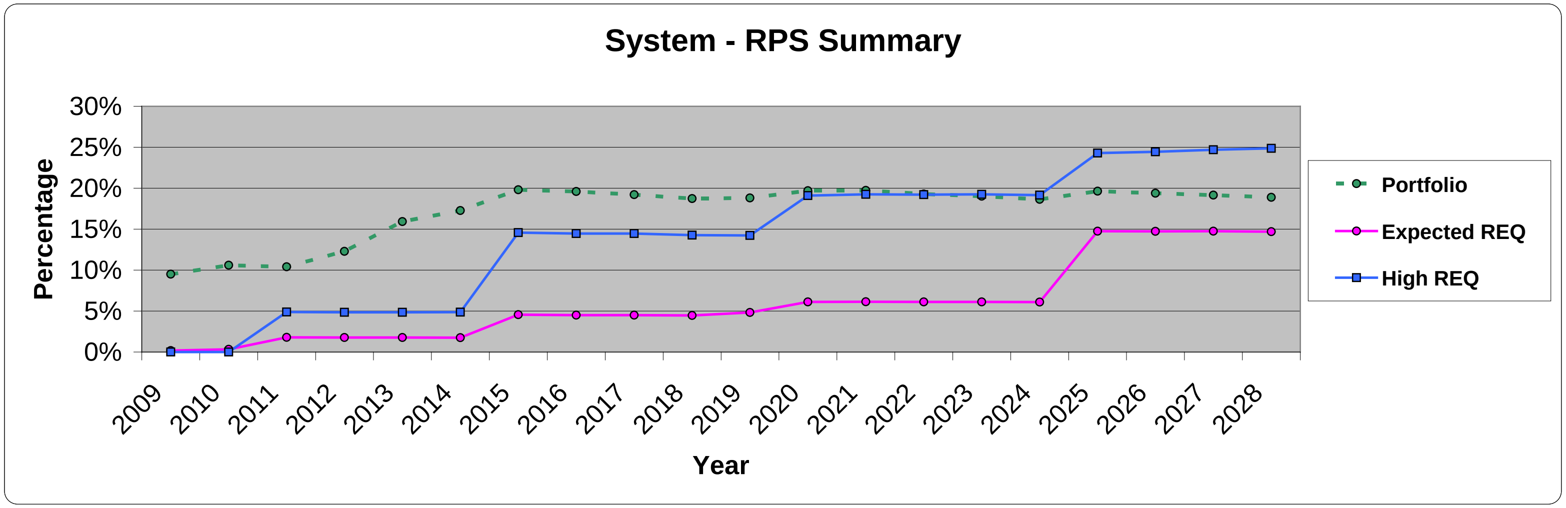


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 12

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,560	8,742	11,973	15,766	20,636	26,036	32,288	38,650	45,037	51,435	58,004	64,776	71,667	78,507	85,362	92,213	92,981	93,639	94,168	94,594
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	478	448	738	1,017	1,018	943	949	938	677	439	461	445	411	385	352	313	276	238
Oregon	1,382	2,536	2,977	3,739	5,083	6,661	7,129	7,606	8,027	8,419	8,841	8,429	7,988	7,446	6,822	6,099	4,294	2,366	301	-
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,429**	**19,953**	**26,457**	**33,715**	**40,435**	**47,199**	**54,013**	**60,792**	**67,523**	**73,644**	**80,116**	**86,398**	**92,596**	**98,697**	**97,627**	**96,318**	**94,745**	**94,832**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,793	4,870	5,401	6,252	6,362	6,387	6,398	6,568	6,772	6,891	6,840	6,855	6,850	6,871	6,892	6,913	6,934
Other (ID,WY)	828	1,031	1,049	1,371	1,950	2,245	2,732	2,804	2,818	2,813	2,905	3,028	3,096	3,065	3,073	3,030	3,055	3,079	3,103	3,126
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	266	303	298	396	591	679	853	872	873	875	901	931	949	939	939	938	932	927	921	916
Oregon	989	1,154	1,149	1,484	2,086	2,341	2,814	2,865	2,860	2,870	2,954	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**7,238**	**9,701**	**10,880**	**12,876**	**13,138**	**13,183**	**13,212**	**13,596**	**14,547**	**14,842**	**14,820**	**14,924**	**14,959**	**16,052**	**16,184**	**16,332**	**16,483**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	10%	11%	10%	12%	16%	17%	20%	20%	19%	19%	19%	20%	20%	19%	19%	19%	20%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

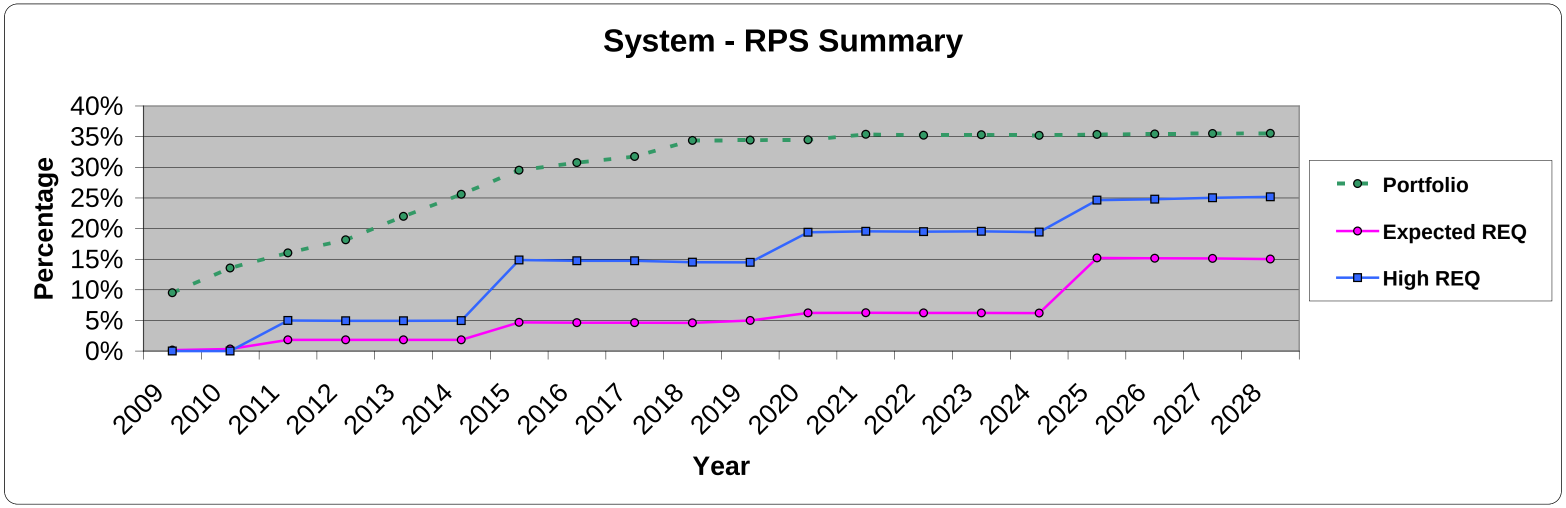


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = High, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 13

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,376	13,814	18,810	24,806	31,771	39,743	48,090	56,704	66,007	75,360	84,743	94,320	103,846	113,387	122,923	127,974	133,073	138,208	143,402
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	419	816	894	1,174	1,524	1,661	1,697	1,811	1,985	1,889	1,666	1,701	1,729	1,727	1,733	1,733	1,728	1,725	1,722
Oregon	1,382	2,925	4,115	5,633	7,698	10,266	11,982	13,909	15,972	18,459	20,961	22,739	24,605	26,447	28,285	30,111	31,198	32,253	33,268	34,243
Cumulative Surplus Credit Bank Balance	**6,942**	**12,720**	**18,744**	**25,337**	**33,678**	**43,561**	**53,386**	**63,695**	**74,487**	**86,451**	**98,210**	**109,148**	**120,626**	**132,023**	**143,399**	**154,767**	**160,905**	**167,054**	**173,201**	**179,367**
Adjusted Qualifying Renewables																				
Utah	2,960	3,816	4,437	4,997	5,995	6,965	7,972	8,347	8,614	9,302	9,353	9,384	9,577	9,526	9,541	9,536	9,557	9,577	9,598	9,620
Other (ID,WY)	828	1,379	1,719	2,043	2,583	3,137	3,719	3,947	4,105	4,486	4,513	4,547	4,664	4,634	4,645	4,598	4,640	4,680	4,721	4,760
California	88	176	185	194	203	235	277	292	301	329	330	327	334	332	332	332	328	323	319	315
Washington	266	419	518	616	796	965	1,167	1,234	1,279	1,405	1,410	1,407	1,439	1,430	1,429	1,428	1,423	1,417	1,412	1,407
Oregon	989	1,543	1,883	2,212	2,763	3,271	3,831	4,033	4,167	4,577	4,588	4,555	4,645	4,605	4,593	4,574	4,521	4,468	4,416	4,364
Adjusted Qualifying Renewables	**5,131**	**7,333**	**8,742**	**10,062**	**12,341**	**14,572**	**16,966**	**17,853**	**18,466**	**20,100**	**20,194**	**20,220**	**20,658**	**20,527**	**20,541**	**20,469**	**20,467**	**20,466**	**20,466**	**20,466**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	14%	16%	18%	22%	26%	30%	31%	32%	34%	34%	34%	35%	35%	35%	35%	35%	35%	36%	36%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

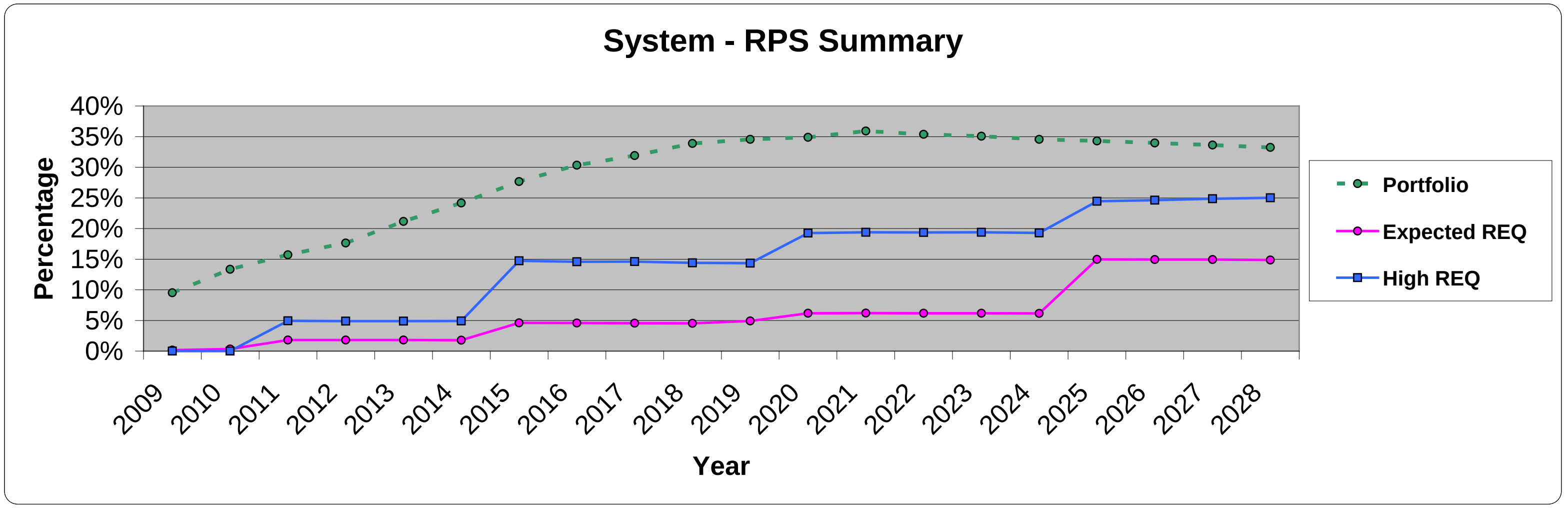


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 14

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,358	13,798	18,800	24,810	31,734	39,687	48,487	57,816	67,819	78,148	88,685	99,594	110,451	121,324	132,192	137,823	143,431	149,004	154,564
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	812	893	1,172	1,511	1,628	1,738	1,979	2,190	2,112	1,939	2,025	2,071	2,055	2,047	2,032	2,012	1,994	1,977
Oregon	1,382	2,914	4,098	5,605	7,657	10,171	11,762	13,818	16,138	18,850	21,711	23,842	26,127	28,352	30,534	32,670	33,895	35,035	36,078	37,025
Cumulative Surplus Credit Bank Balance	**6,942**	**12,687**	**18,708**	**25,298**	**33,640**	**43,416**	**53,078**	**64,044**	**75,932**	**88,859**	**101,970**	**114,465**	**127,745**	**140,874**	**153,913**	**166,909**	**173,750**	**180,478**	**187,076**	**193,566**
Adjusted Qualifying Renewables																				
Utah	2,960	3,798	4,440	5,002	6,010	6,924	7,953	8,800	9,328	10,004	10,328	10,537	10,909	10,858	10,873	10,868	10,888	10,909	10,930	10,952
Other (ID,WY)	828	1,369	1,720	2,046	2,591	3,113	3,708	4,208	4,517	4,891	5,076	5,218	5,441	5,412	5,425	5,375	5,425	5,474	5,523	5,571
California	88	176	185	194	204	233	276	310	330	357	369	373	387	385	386	386	381	376	371	366
Washington	266	415	519	617	799	957	1,164	1,317	1,410	1,533	1,588	1,618	1,683	1,673	1,673	1,672	1,666	1,661	1,655	1,650
Oregon	989	1,532	1,885	2,215	2,772	3,246	3,820	4,300	4,586	4,990	5,161	5,227	5,419	5,378	5,364	5,348	5,286	5,226	5,166	5,107
Adjusted Qualifying Renewables	**5,131**	**7,290**	**8,748**	**10,075**	**12,376**	**14,473**	**16,921**	**18,934**	**20,171**	**21,774**	**22,522**	**22,973**	**23,837**	**23,706**	**23,720**	**23,648**	**23,647**	**23,646**	**23,645**	**23,645**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	21%	24%	28%	30%	32%	34%	35%	35%	36%	35%	35%	35%	34%	34%	34%	33%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

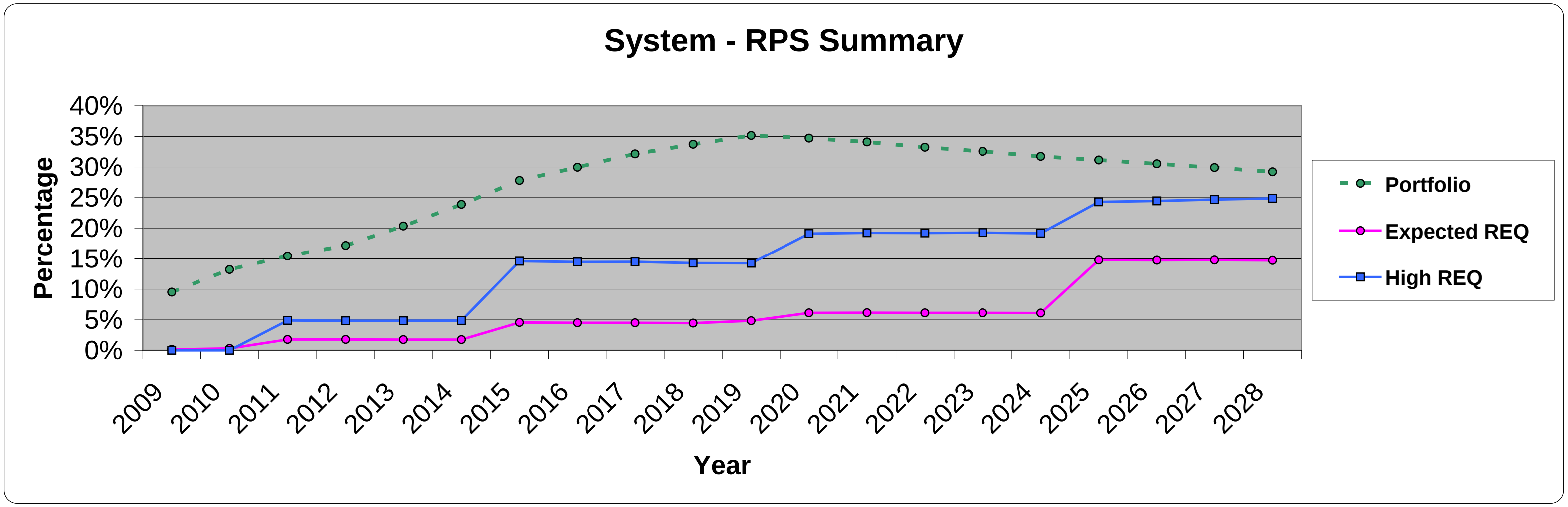


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 15

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,560	9,360	13,806	18,818	24,828	31,995	40,428	49,705	59,818	70,653	82,185	93,837	105,503	117,118	128,749	140,374	145,917	151,350	156,655	161,855
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	416	813	893	1,169	1,548	1,739	1,874	2,162	2,429	2,394	2,236	2,224	2,189	2,155	2,129	2,096	2,057	2,020	1,982
Oregon	1,382	2,915	4,095	5,595	7,624	10,252	12,009	14,201	16,808	19,808	23,145	25,577	27,910	30,140	32,281	34,330	35,271	36,061	36,686	37,145
Cumulative Surplus Credit Bank Balance	**6,942**	**12,691**	**18,714**	**25,306**	**33,621**	**43,796**	**54,176**	**65,779**	**78,788**	**92,891**	**107,725**	**121,650**	**135,638**	**149,448**	**163,185**	**176,834**	**183,284**	**189,468**	**195,360**	**200,982**
Adjusted Qualifying Renewables																				
Utah	2,960	3,800	4,446	5,012	6,009	7,168	8,433	9,277	10,113	10,835	11,532	11,652	11,666	11,615	11,630	11,625	11,646	11,667	11,688	11,709
Other (ID,WY)	828	1,371	1,723	2,052	2,591	3,253	3,983	4,482	4,971	5,370	5,771	5,867	5,883	5,854	5,868	5,817	5,872	5,926	5,979	6,031
California	88	176	185	194	204	243	296	329	361	390	417	417	417	416	416	416	412	419	428	436
Washington	266	416	520	619	799	1,002	1,252	1,404	1,553	1,685	1,808	1,822	1,821	1,811	1,811	1,810	1,804	1,799	1,793	1,788
Oregon	989	1,533	1,888	2,221	2,772	3,391	4,103	4,580	5,047	5,479	5,867	5,877	5,859	5,818	5,803	5,788	5,722	5,657	5,593	5,529
Adjusted Qualifying Renewables	**5,131**	**7,295**	**8,762**	**10,100**	**12,375**	**15,056**	**18,065**	**20,072**	**22,046**	**23,758**	**25,395**	**25,634**	**25,645**	**25,514**	**25,528**	**25,456**	**25,456**	**25,468**	**25,481**	**25,494**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	10%	13%	15%	17%	20%	24%	28%	30%	32%	34%	35%	35%	34%	33%	33%	32%	31%	31%	30%	29%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

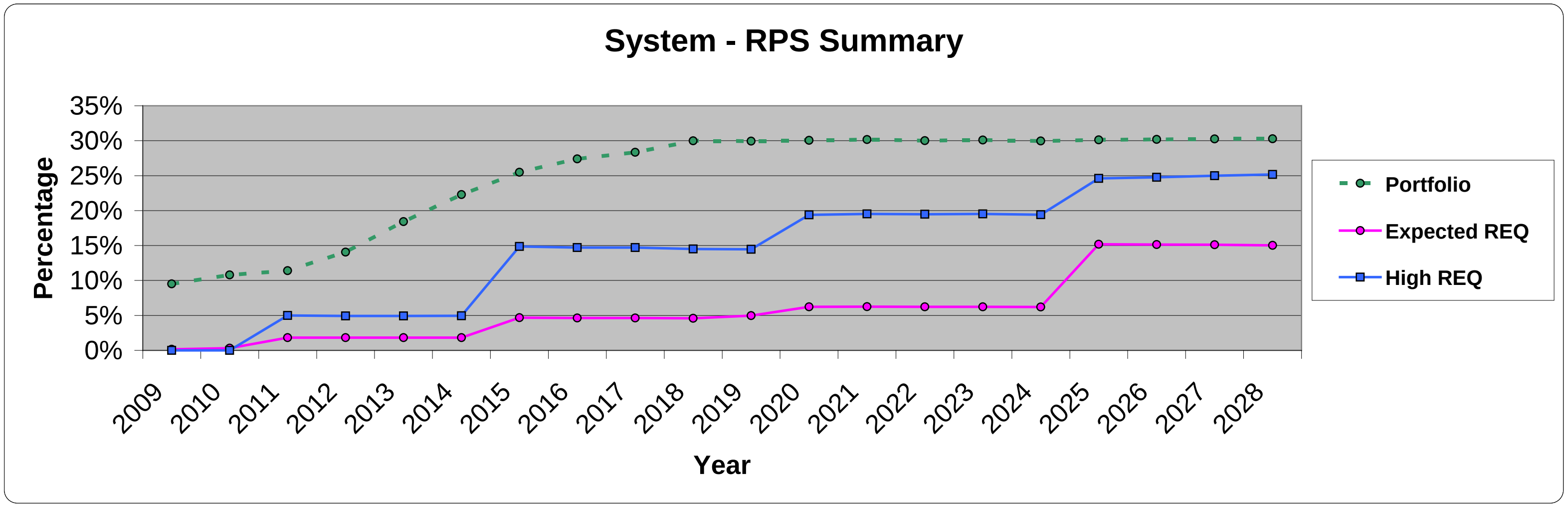


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = High, Renewable Std = None 6/, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 16

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	8,741	12,106	16,134	21,283	27,455	34,461	41,993	49,775	58,005	66,259	74,544	82,843	91,091	99,355	107,613	111,387	115,207	119,064	122,981
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	504	521	842	1,224	1,339	1,371	1,511	1,638	1,493	1,265	1,267	1,262	1,260	1,266	1,266	1,261	1,258	1,255
Oregon	1,382	2,535	3,073	4,005	5,561	7,658	8,802	10,250	11,825	13,681	15,538	16,675	17,799	18,900	19,998	21,082	21,435	21,763	22,058	22,320
Cumulative Surplus Credit Bank Balance	**6,942**	**11,579**	**15,683**	**20,660**	**27,686**	**36,337**	**44,602**	**53,614**	**63,110**	**73,324**	**83,290**	**92,484**	**101,909**	**111,254**	**120,612**	**129,962**	**134,087**	**138,231**	**142,380**	**146,556**
Adjusted Qualifying Renewables																				
Utah	2,959	3,181	3,365	4,028	5,148	6,172	7,005	7,532	7,782	8,230	8,254	8,285	8,299	8,248	8,263	8,258	8,279	8,300	8,321	8,342
Other (ID,WY)	828	1,031	1,124	1,502	2,106	2,685	3,164	3,478	3,624	3,868	3,878	3,908	3,918	3,888	3,897	3,852	3,886	3,919	3,951	3,983
California	88	176	185	194	203	212	238	259	268	286	286	302	302	301	300	299	299	297	296	295
Washington	266	303	322	439	642	820	991	1,085	1,127	1,209	1,209	1,207	1,206	1,197	1,196	1,195	1,190	1,184	1,179	1,173
Oregon	989	1,153	1,231	1,626	2,254	2,800	3,260	3,554	3,679	3,947	3,943	3,914	3,902	3,864	3,853	3,832	3,786	3,741	3,696	3,651
Adjusted Qualifying Renewables	**5,130**	**5,844**	**6,227**	**7,789**	**10,353**	**12,690**	**14,658**	**15,908**	**16,479**	**17,540**	**17,571**	**17,616**	**17,627**	**17,497**	**17,510**	**17,437**	**17,439**	**17,440**	**17,443**	**17,445**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	11%	11%	14%	18%	22%	25%	27%	28%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

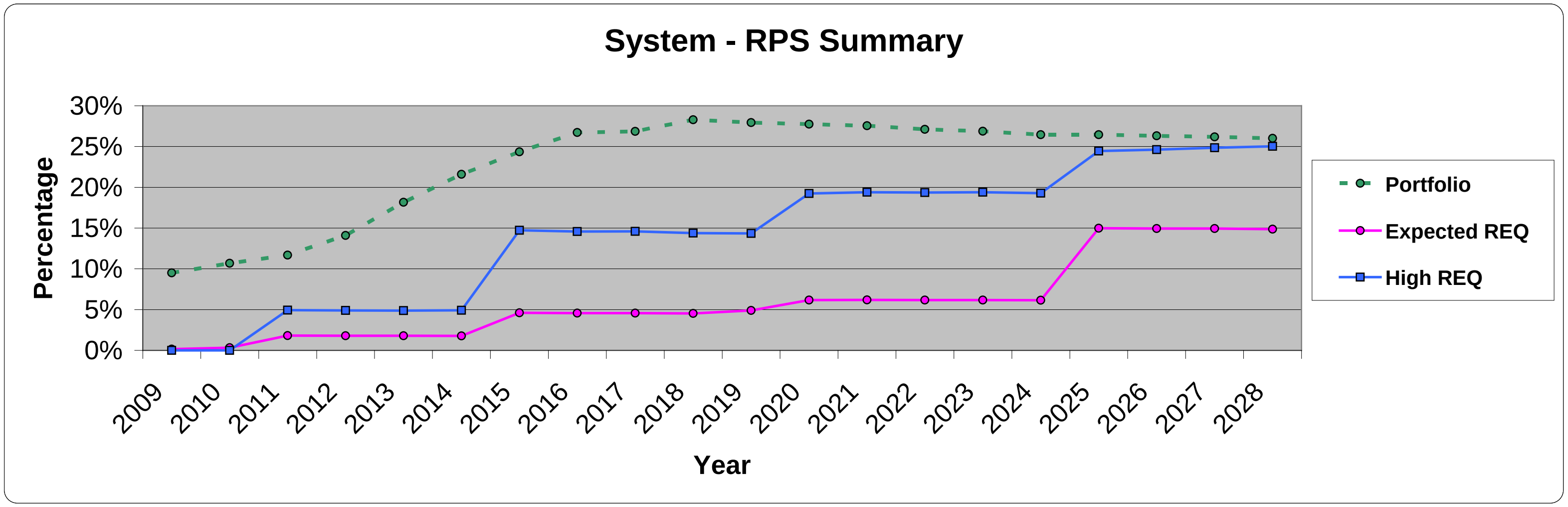


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 17

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,741	12,223	16,364	21,626	27,903	35,005	42,862	50,854	59,351	67,873	76,426	84,993	93,509	102,040	110,566	113,855	117,122	120,352	123,571
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	525	560	878	1,257	1,355	1,411	1,563	1,671	1,507	1,246	1,235	1,216	1,200	1,192	1,177	1,157	1,139	1,121
Oregon	1,382	2,535	3,137	4,123	5,725	7,855	8,943	10,444	11,979	13,806	15,606	16,580	17,505	18,370	19,197	19,973	19,852	19,659	19,383	19,024
Cumulative Surplus Credit Bank Balance	**6,942**	**11,579**	**15,885**	**21,048**	**28,230**	**37,014**	**45,303**	**54,717**	**64,395**	**74,828**	**84,986**	**94,252**	**103,732**	**113,095**	**122,436**	**131,731**	**134,884**	**137,938**	**140,874**	**143,716**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,482	4,141	5,262	6,277	7,102	7,857	7,991	8,498	8,522	8,553	8,567	8,516	8,531	8,526	8,547	8,567	8,589	8,610
Other (ID,WY)	828	1,031	1,188	1,565	2,170	2,745	3,219	3,665	3,745	4,023	4,033	4,064	4,074	4,044	4,054	4,008	4,044	4,078	4,112	4,146
California	88	176	185	194	204	213	242	272	276	296	296	336	339	341	345	348	352	354	357	360
Washington	266	303	344	460	662	839	1,009	1,145	1,166	1,258	1,258	1,256	1,255	1,245	1,245	1,244	1,238	1,233	1,227	1,222
Oregon	989	1,153	1,302	1,694	2,322	2,862	3,317	3,745	3,802	4,104	4,100	4,070	4,058	4,019	4,008	3,988	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,844**	**6,501**	**8,055**	**10,620**	**12,936**	**14,889**	**16,683**	**16,979**	**18,179**	**18,210**	**18,278**	**18,293**	**18,166**	**18,183**	**18,114**	**18,242**	**18,319**	**18,408**	**18,497**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	12%	14%	18%	22%	24%	27%	27%	28%	28%	28%	28%	27%	27%	26%	26%	26%	26%	26%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

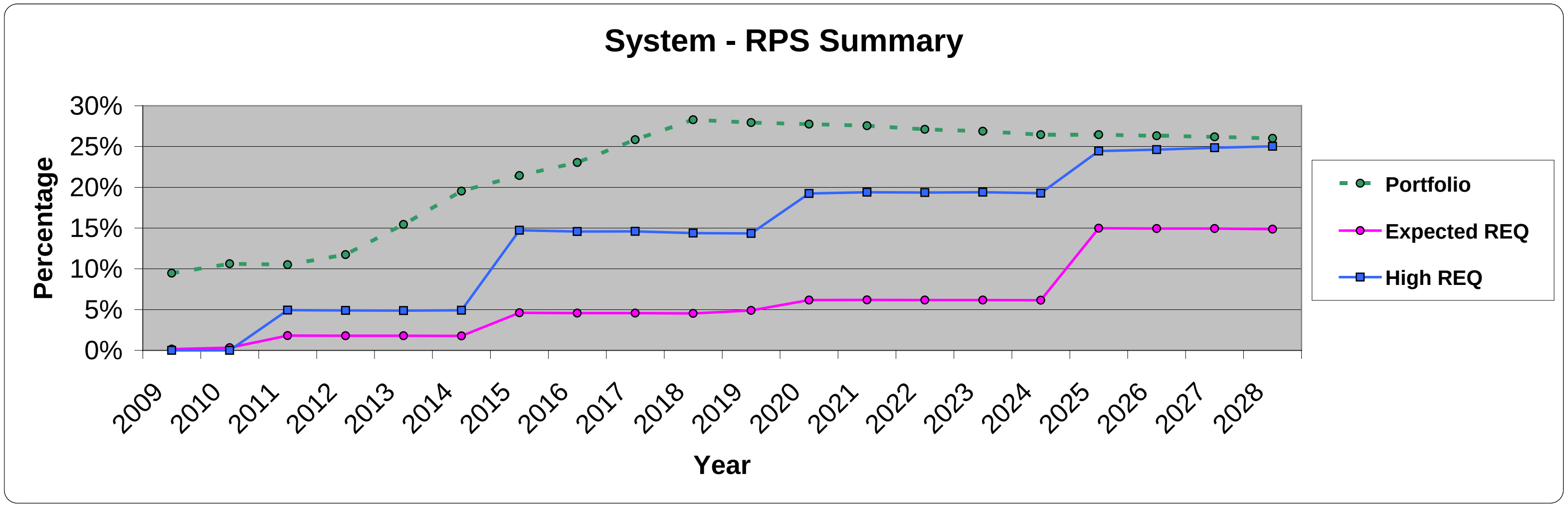


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 18

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,486	20,073	25,826	32,177	39,071	46,792	55,290	63,812	72,365	80,932	89,448	97,979	106,505	109,794	113,061	116,291	119,510
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	405	650	1,038	1,122	1,098	1,337	1,622	1,507	1,246	1,235	1,216	1,200	1,192	1,177	1,157	1,139	1,121
Oregon	1,376	2,519	2,952	3,591	4,787	6,605	7,250	8,184	9,561	11,387	13,188	14,162	15,086	15,952	16,778	17,555	17,434	17,240	16,964	16,605
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**19,481**	**25,510**	**33,468**	**40,549**	**48,353**	**57,690**	**68,299**	**78,507**	**87,773**	**97,253**	**106,616**	**115,956**	**125,251**	**128,404**	**131,458**	**134,395**	**137,237**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,566	4,587	5,753	6,352	6,894	7,721	8,498	8,522	8,553	8,567	8,516	8,531	8,526	8,547	8,567	8,589	8,610
Other (ID,WY)	822	1,022	1,034	1,244	1,791	2,446	2,789	3,110	3,589	4,023	4,033	4,064	4,074	4,044	4,054	4,008	4,044	4,078	4,112	4,146
California	88	176	185	194	204	213	223	233	266	296	296	336	339	341	345	348	352	354	357	360
Washington	264	300	293	355	539	743	872	969	1,116	1,258	1,258	1,256	1,255	1,245	1,245	1,244	1,238	1,233	1,227	1,222
Oregon	982	1,144	1,133	1,347	1,916	2,550	2,873	3,178	3,643	4,104	4,100	4,070	4,058	4,019	4,008	3,988	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**6,706**	**9,038**	**11,706**	**13,108**	**14,384**	**16,335**	**18,179**	**18,210**	**18,278**	**18,293**	**18,166**	**18,183**	**18,114**	**18,242**	**18,319**	**18,408**	**18,497**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	12%	15%	20%	21%	23%	26%	28%	28%	28%	28%	27%	27%	26%	26%	26%	26%	26%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

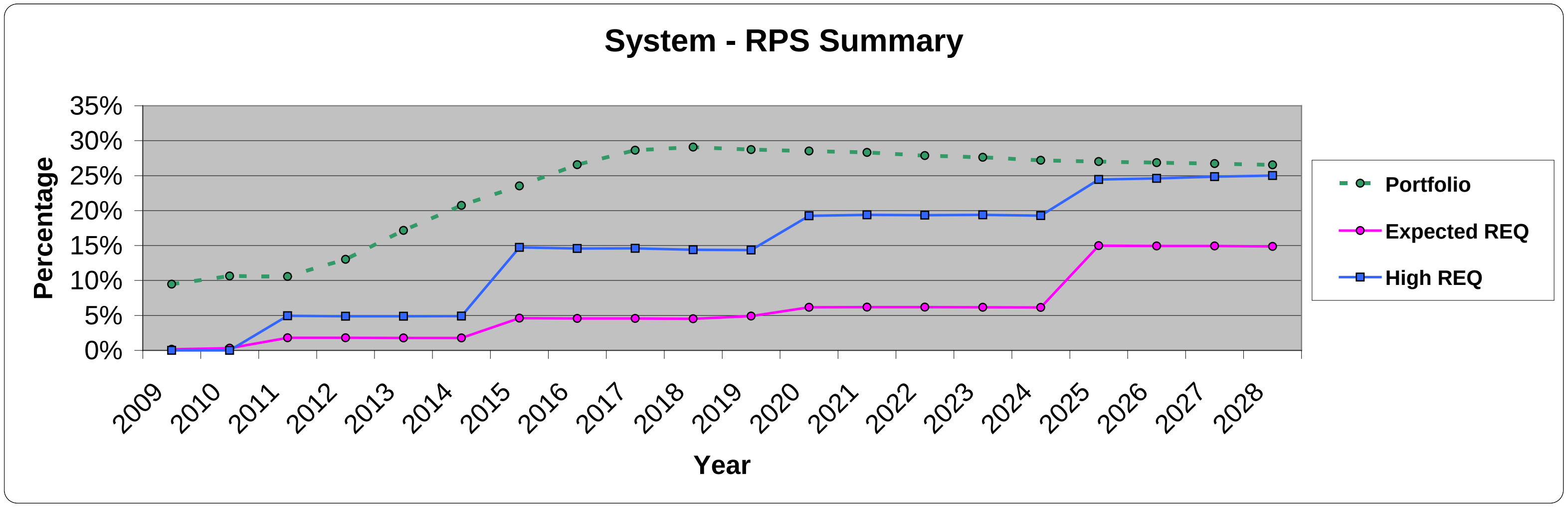


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 19

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,551	8,720	11,939	15,821	20,833	26,895	33,787	41,603	50,065	58,779	67,517	76,285	85,069	93,801	102,548	111,290	114,795	118,278	121,724	125,159
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	474	465	786	1,172	1,277	1,365	1,641	1,797	1,586	1,325	1,314	1,295	1,279	1,270	1,256	1,236	1,218	1,200
Oregon	1,376	2,522	2,964	3,794	5,245	7,247	8,211	9,688	11,499	13,453	15,380	16,480	17,530	18,521	19,472	20,375	20,378	20,307	20,153	19,915
Cumulative Surplus Credit Bank Balance	**6,927**	**11,542**	**15,377**	**20,080**	**26,864**	**35,314**	**43,276**	**52,655**	**63,205**	**74,028**	**84,483**	**94,091**	**103,912**	**113,617**	**123,299**	**132,935**	**136,428**	**139,821**	**143,096**	**146,274**
Adjusted Qualifying Renewables																				
Utah	2,950	3,169	3,219	3,882	5,012	6,062	6,892	7,815	8,462	8,714	8,738	8,769	8,783	8,732	8,747	8,742	8,763	8,783	8,805	8,826
Other (ID,WY)	823	1,024	1,043	1,421	2,030	2,622	3,099	3,641	4,017	4,147	4,158	4,189	4,200	4,170	4,180	4,135	4,171	4,207	4,242	4,277
California	88	176	185	194	204	213	234	270	295	305	305	336	339	341	345	348	352	354	357	360
Washington	264	300	296	413	617	800	970	1,137	1,252	1,297	1,298	1,295	1,294	1,285	1,284	1,283	1,278	1,272	1,267	1,262
Oregon	983	1,146	1,142	1,538	2,172	2,734	3,193	3,720	4,078	4,231	4,227	4,196	4,183	4,145	4,133	4,113	4,064	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,109**	**5,815**	**5,884**	**7,447**	**10,034**	**12,431**	**14,388**	**16,583**	**18,104**	**18,694**	**18,726**	**18,785**	**18,800**	**18,673**	**18,690**	**18,621**	**18,628**	**18,703**	**18,794**	**18,884**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	21%	24%	27%	29%	29%	29%	29%	28%	28%	28%	27%	27%	27%	27%	27%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

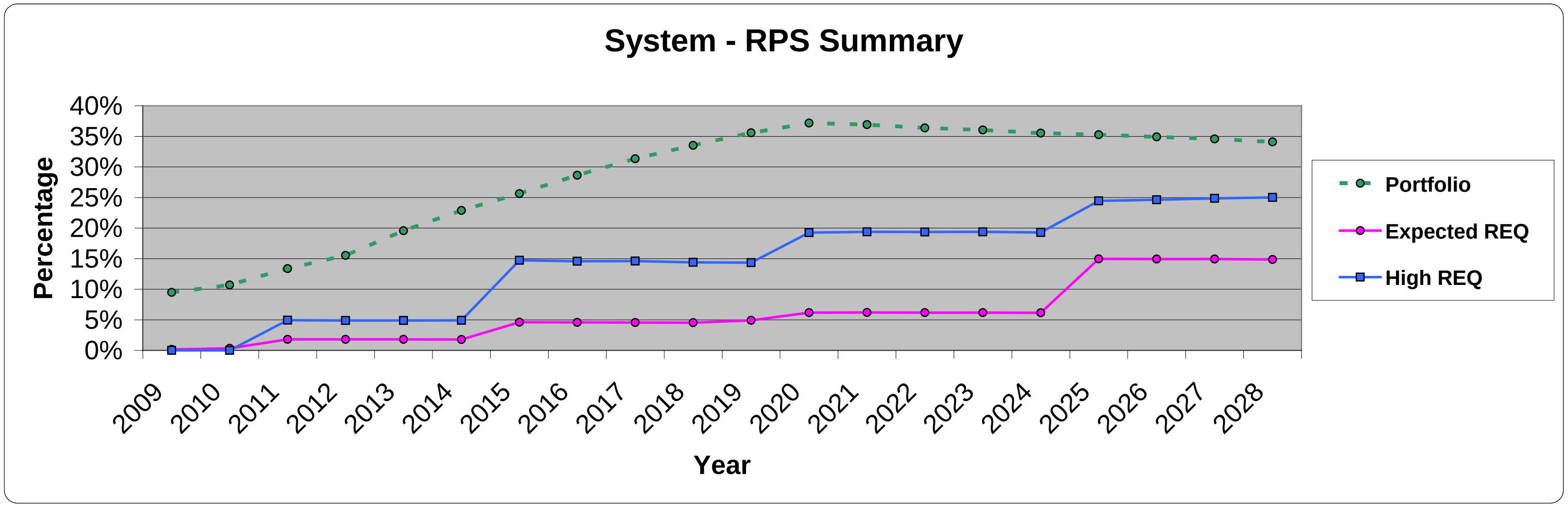


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 20

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,556	8,739	12,623	17,116	22,729	29,335	36,768	45,123	54,303	64,213	74,820	85,995	97,184	108,323	119,476	130,625	136,537	142,426	148,279	154,095
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	598	698	1,007	1,381	1,476	1,562	1,870	2,146	2,146	2,106	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,075
Oregon	1,380	2,534	3,380	4,579	6,392	8,718	10,001	11,795	14,027	16,684	19,709	22,211	24,660	27,048	29,392	31,692	33,079	34,378	35,579	36,669
Cumulative Surplus Credit Bank Balance	**6,936**	**11,576**	**16,601**	**22,393**	**30,128**	**39,434**	**48,245**	**58,479**	**70,200**	**83,043**	**96,674**	**110,312**	**124,037**	**137,545**	**151,026**	**164,466**	**171,750**	**178,918**	**185,955**	**192,839**
Adjusted Qualifying Renewables																				
Utah	2,956	3,183	3,884	4,493	5,613	6,607	7,433	8,354	9,180	9,910	10,607	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,207
Other (ID,WY)	826	1,032	1,411	1,762	2,368	2,933	3,409	3,951	4,432	4,837	5,237	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,726
California	88	176	185	194	204	220	255	292	324	353	380	398	398	397	397	397	392	387	382	376
Washington	265	303	417	524	726	899	1,069	1,235	1,383	1,516	1,639	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,696
Oregon	986	1,154	1,546	1,907	2,533	3,058	3,512	4,037	4,499	4,935	5,324	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,249
Adjusted Qualifying Renewables	**5,122**	**5,847**	**7,443**	**8,881**	**11,443**	**13,717**	**15,679**	**17,870**	**19,817**	**21,550**	**23,187**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,255**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	16%	20%	23%	26%	29%	31%	34%	36%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

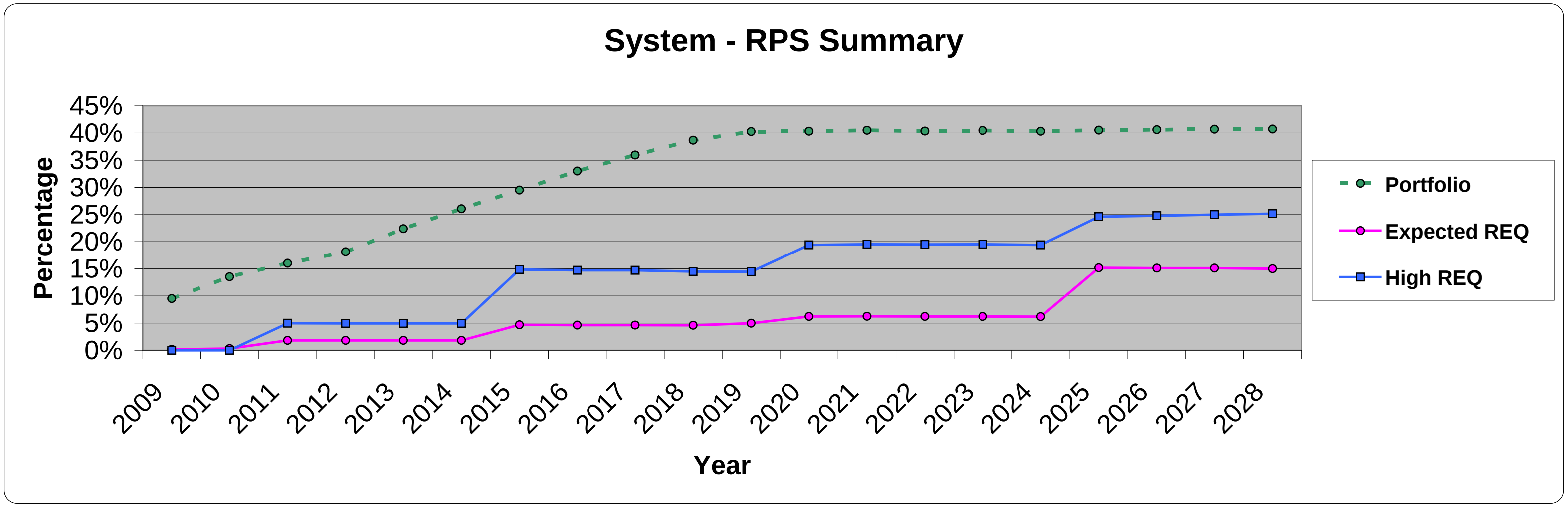


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 21

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,376	13,813	18,809	24,903	31,980	39,953	48,848	58,484	68,842	79,628	90,445	101,276	112,056	122,852	133,642	139,948	146,300	152,689	159,138
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	419	816	893	1,192	1,562	1,681	1,797	2,098	2,365	2,343	2,189	2,192	2,187	2,185	2,191	2,191	2,186	2,183	2,180
Oregon	1,382	2,925	4,114	5,632	7,757	10,391	12,107	14,356	17,019	20,127	23,470	26,083	28,678	31,249	33,812	36,367	38,176	39,944	41,666	43,340
Cumulative Surplus Credit Bank Balance	**6,942**	**12,720**	**18,742**	**25,335**	**33,852**	**43,934**	**53,741**	**65,001**	**77,602**	**91,333**	**105,441**	**118,717**	**132,146**	**145,492**	**158,849**	**172,200**	**180,314**	**188,431**	**196,538**	**204,659**
Adjusted Qualifying Renewables																				
Utah	2,960	3,816	4,437	4,996	6,094	7,077	7,972	8,895	9,637	10,357	10,786	10,817	10,831	10,780	10,795	10,790	10,811	10,832	10,853	10,874
Other (ID,WY)	828	1,379	1,718	2,043	2,638	3,201	3,719	4,262	4,695	5,094	5,340	5,381	5,396	5,366	5,380	5,330	5,380	5,428	5,476	5,523
California	88	176	185	194	205	239	277	314	342	371	387	384	384	382	383	382	377	373	368	363
Washington	266	419	518	616	814	985	1,167	1,334	1,466	1,598	1,672	1,669	1,668	1,659	1,658	1,657	1,652	1,646	1,641	1,636
Oregon	989	1,543	1,882	2,212	2,823	3,337	3,831	4,356	4,767	5,198	5,430	5,390	5,374	5,334	5,319	5,303	5,242	5,182	5,122	5,064
Adjusted Qualifying Renewables	**5,131**	**7,333**	**8,740**	**10,062**	**12,574**	**14,839**	**16,966**	**19,161**	**20,907**	**22,618**	**23,615**	**23,641**	**23,652**	**23,521**	**23,535**	**23,463**	**23,462**	**23,461**	**23,460**	**23,460**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	14%	16%	18%	22%	26%	30%	33%	36%	39%	40%	40%	40%	40%	40%	40%	41%	41%	41%	41%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

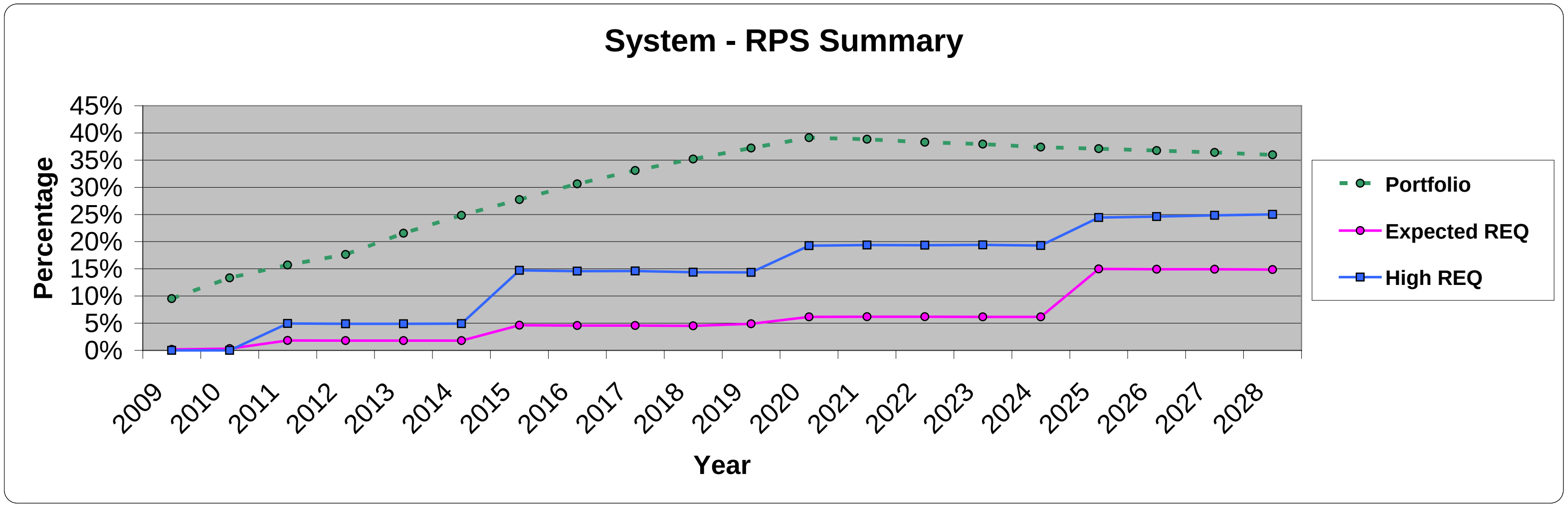


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 22

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,357	13,796	18,803	24,907	32,004	39,976	48,849	58,486	68,843	79,898	91,609	103,335	115,010	126,700	138,385	144,833	151,258	157,648	164,026
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	812	893	1,190	1,560	1,663	1,755	2,049	2,311	2,309	2,286	2,388	2,370	2,353	2,345	2,330	2,311	2,293	2,275
Oregon	1,382	2,913	4,097	5,607	7,716	10,332	11,935	14,033	16,533	19,454	22,741	25,556	28,316	31,016	33,670	36,282	37,977	39,581	41,085	42,488
Cumulative Surplus Credit Bank Balance	**6,942**	**12,685**	**18,705**	**25,304**	**33,813**	**43,896**	**53,574**	**64,637**	**77,068**	**90,609**	**104,948**	**119,451**	**134,040**	**148,395**	**162,724**	**177,012**	**185,140**	**193,150**	**201,025**	**208,788**
Adjusted Qualifying Renewables																				
Utah	2,960	3,797	4,440	5,007	6,104	7,096	7,972	8,873	9,637	10,358	11,054	11,711	11,726	11,675	11,690	11,685	11,705	11,726	11,747	11,769
Other (ID,WY)	828	1,369	1,720	2,049	2,644	3,212	3,719	4,250	4,695	5,095	5,495	5,902	5,918	5,889	5,903	5,852	5,907	5,962	6,015	6,068
California	88	176	185	194	205	240	277	313	342	371	398	419	419	418	419	418	413	408	402	397
Washington	266	415	518	618	816	989	1,167	1,330	1,466	1,598	1,721	1,833	1,832	1,822	1,822	1,821	1,815	1,810	1,804	1,799
Oregon	989	1,531	1,884	2,218	2,829	3,349	3,831	4,342	4,767	5,198	5,587	5,911	5,893	5,853	5,837	5,822	5,756	5,691	5,626	5,563
Adjusted Qualifying Renewables	**5,131**	**7,287**	**8,747**	**10,086**	**12,598**	**14,886**	**16,966**	**19,108**	**20,907**	**22,619**	**24,255**	**25,776**	**25,788**	**25,657**	**25,671**	**25,599**	**25,597**	**25,596**	**25,596**	**25,595**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	39%	39%	38%	38%	37%	37%	37%	36%	36%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

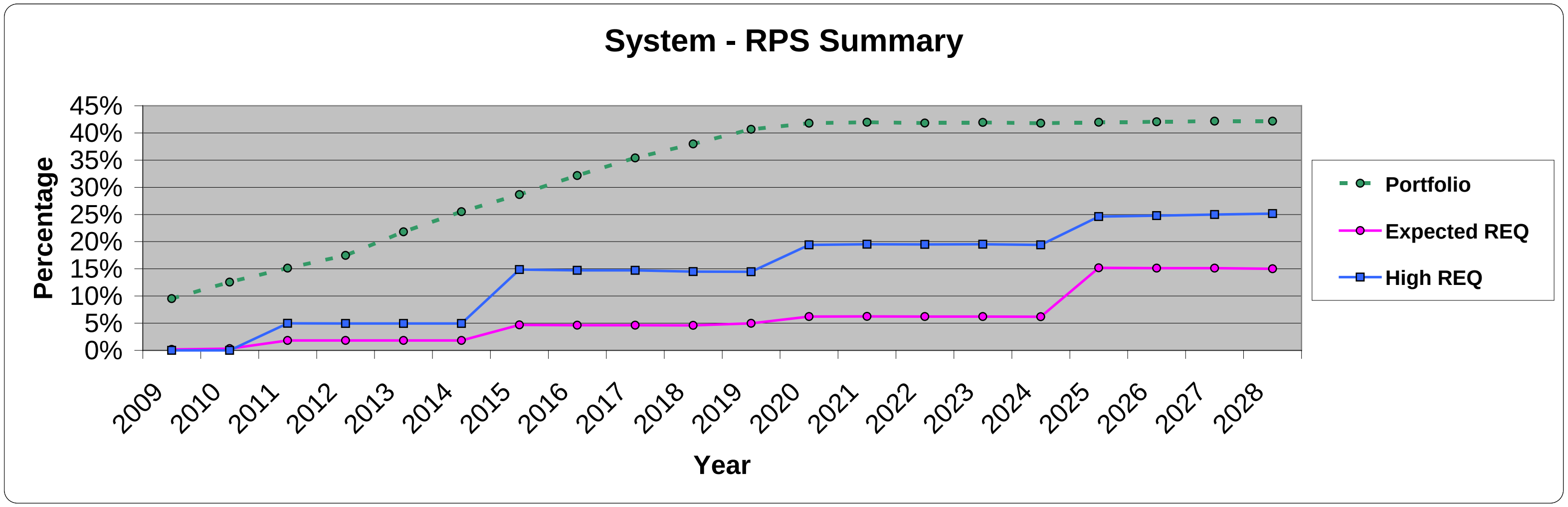


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 23

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,144	13,372	18,206	24,161	31,107	38,875	47,564	57,068	67,255	78,140	89,315	100,505	111,644	122,797	133,946	140,605	147,311	154,053	160,856
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	376	735	825	1,136	1,513	1,620	1,722	2,036	2,310	2,331	2,273	2,322	2,318	2,316	2,322	2,321	2,315	2,312	2,309
Oregon	1,382	2,783	3,845	5,264	7,305	9,862	11,457	13,585	16,170	19,178	22,579	25,401	28,204	30,983	33,754	36,517	38,528	40,498	42,419	44,290
Cumulative Surplus Credit Bank Balance	**6,942**	**12,303**	**17,952**	**24,295**	**32,603**	**42,481**	**51,951**	**62,871**	**75,274**	**88,743**	**103,050**	**116,989**	**131,032**	**144,944**	**158,866**	**172,784**	**181,453**	**190,124**	**198,784**	**207,455**
Adjusted Qualifying Renewables																				
Utah	2,959	3,585	4,228	4,833	5,955	6,946	7,768	8,689	9,503	10,188	10,885	11,175	11,190	11,138	11,154	11,149	11,164	11,185	11,206	11,228
Other (ID,WY)	828	1,252	1,602	1,952	2,560	3,126	3,601	4,144	4,619	4,997	5,397	5,590	5,605	5,576	5,589	5,539	5,588	5,639	5,689	5,739
California	88	176	185	194	203	234	269	305	337	364	391	398	398	397	397	397	391	386	381	376
Washington	266	376	480	586	789	961	1,130	1,297	1,442	1,567	1,690	1,735	1,734	1,724	1,724	1,723	1,716	1,711	1,705	1,700
Oregon	989	1,401	1,755	2,113	2,739	3,259	3,710	4,234	4,689	5,098	5,487	5,599	5,582	5,541	5,527	5,511	5,445	5,383	5,322	5,261
Adjusted Qualifying Renewables	**5,130**	**6,790**	**8,250**	**9,679**	**12,247**	**14,526**	**16,478**	**18,670**	**20,589**	**22,213**	**23,851**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,305**	**24,304**	**24,304**	**24,304**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	13%	15%	17%	22%	26%	29%	32%	35%	38%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

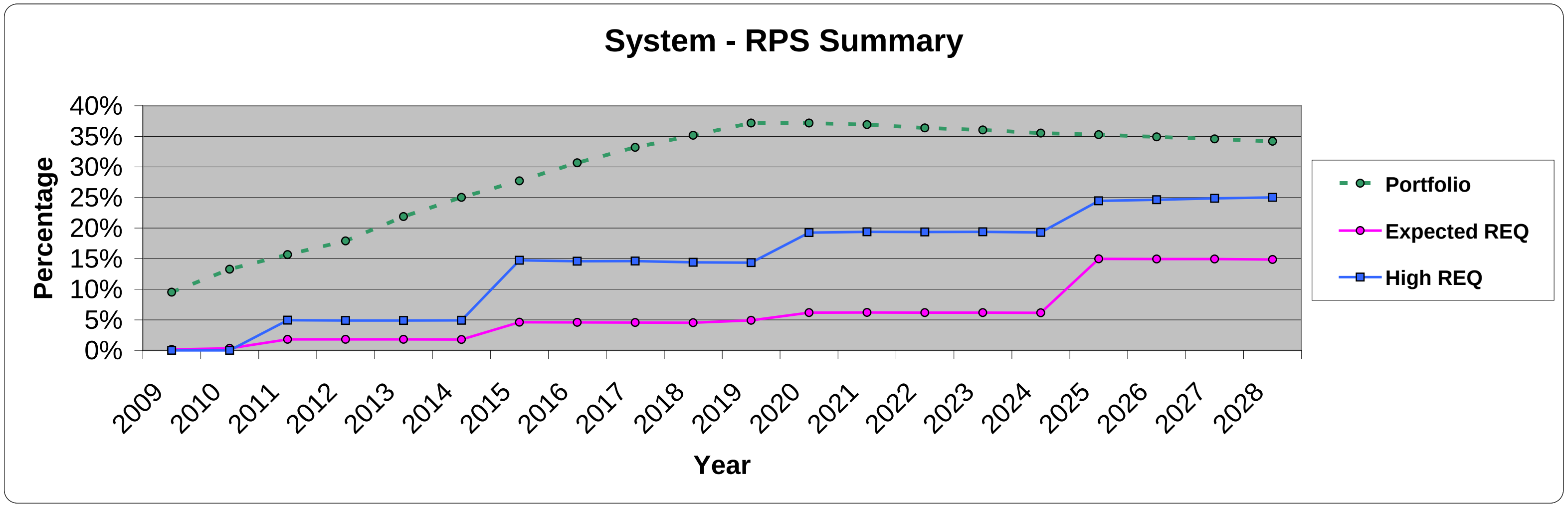


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 24

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,342	13,768	18,835	25,025	32,165	40,127	49,011	58,675	69,023	80,068	91,244	102,433	113,572	124,725	135,874	141,785	147,675	153,528	159,369
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	412	807	902	1,217	1,584	1,670	1,755	2,056	2,315	2,306	2,186	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,079
Oregon	1,382	2,904	4,079	5,626	7,787	10,429	12,025	14,130	16,647	19,561	22,843	25,346	27,794	30,182	32,527	34,826	36,213	37,512	38,714	39,817
Cumulative Surplus Credit Bank Balance	**6,942**	**12,659**	**18,654**	**25,363**	**34,029**	**44,178**	**53,822**	**64,896**	**77,378**	**90,899**	**105,217**	**118,775**	**132,420**	**145,928**	**159,409**	**172,849**	**180,133**	**187,302**	**194,338**	**201,266**
Adjusted Qualifying Renewables																				
Utah	2,959	3,783	4,426	5,067	6,190	7,140	7,962	8,884	9,664	10,348	11,045	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,233
Other (ID,WY)	828	1,361	1,712	2,083	2,692	3,237	3,713	4,256	4,711	5,089	5,490	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,741
California	88	176	185	194	209	242	277	313	343	370	398	398	398	397	397	397	392	387	382	377
Washington	266	412	516	629	832	997	1,166	1,332	1,471	1,596	1,719	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,701
Oregon	989	1,522	1,876	2,254	2,880	3,375	3,825	4,349	4,783	5,192	5,581	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,264
Adjusted Qualifying Renewables	**5,130**	**7,254**	**8,714**	**10,228**	**12,803**	**14,990**	**16,942**	**19,134**	**20,973**	**22,596**	**24,233**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,315**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

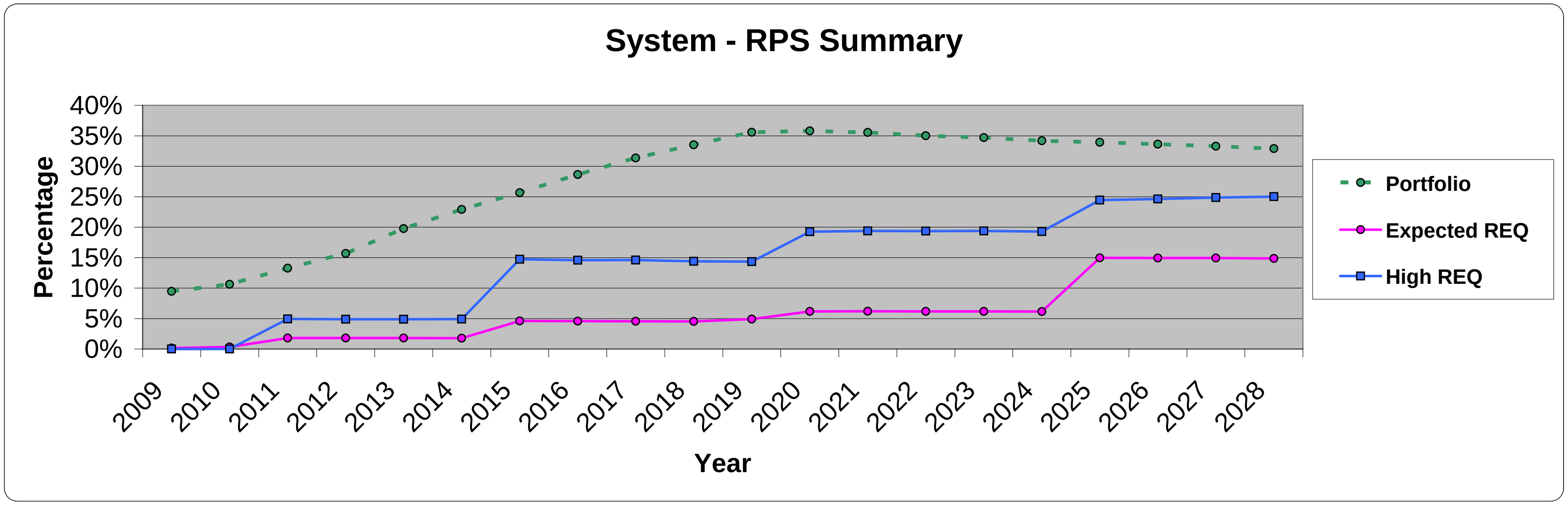


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 25

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	12,573	17,100	22,763	29,375	36,809	45,165	54,347	64,257	74,864	85,658	96,466	107,224	117,997	128,764	134,295	139,803	145,275	150,736
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	590	699	1,022	1,391	1,477	1,562	1,871	2,146	2,146	2,036	2,053	2,035	2,018	2,010	1,995	1,976	1,958	1,940
Oregon	1,376	2,519	3,349	4,569	6,412	8,741	10,025	11,820	14,053	16,710	19,735	22,015	24,242	26,409	28,533	30,611	31,779	32,862	33,848	34,740
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**16,512**	**22,369**	**30,197**	**39,507**	**48,311**	**58,547**	**70,271**	**83,113**	**96,744**	**109,709**	**122,762**	**135,668**	**148,548**	**161,386**	**168,069**	**174,641**	**181,082**	**187,416**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,857	4,528	5,662	6,612	7,434	8,356	9,181	9,910	10,607	10,794	10,809	10,758	10,773	10,768	10,788	10,809	10,830	10,852
Other (ID,WY)	822	1,022	1,397	1,781	2,396	2,936	3,410	3,952	4,432	4,837	5,237	5,368	5,382	5,353	5,366	5,317	5,366	5,415	5,463	5,510
California	88	176	185	194	204	220	255	292	324	353	380	383	383	381	382	382	377	372	367	362
Washington	264	300	412	531	735	900	1,069	1,236	1,383	1,516	1,639	1,665	1,664	1,655	1,654	1,653	1,648	1,642	1,637	1,631
Oregon	982	1,144	1,530	1,928	2,563	3,061	3,513	4,038	4,500	4,935	5,324	5,377	5,360	5,320	5,306	5,290	5,229	5,169	5,110	5,051
Adjusted Qualifying Renewables	**5,106**	**5,807**	**7,381**	**8,962**	**11,560**	**13,730**	**15,681**	**17,874**	**19,820**	**21,550**	**23,187**	**23,587**	**23,598**	**23,467**	**23,481**	**23,409**	**23,408**	**23,407**	**23,406**	**23,406**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	16%	20%	23%	26%	29%	31%	34%	36%	36%	36%	35%	35%	34%	34%	34%	33%	33%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

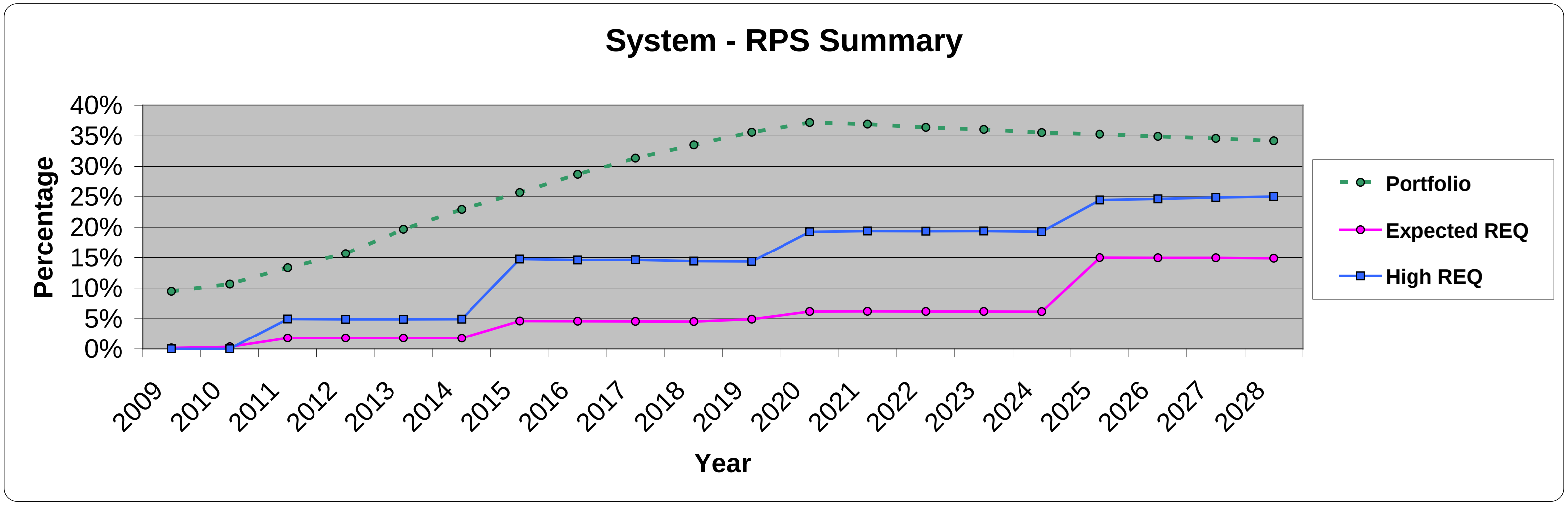


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 26

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,551	8,720	12,589	17,108	22,749	29,361	36,795	45,151	54,333	64,243	74,850	86,025	97,215	108,353	119,507	130,655	136,567	142,456	148,309	154,151
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	593	700	1,017	1,387	1,477	1,562	1,871	2,147	2,146	2,106	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,079
Oregon	1,376	2,522	3,359	4,574	6,404	8,733	10,017	11,812	14,045	16,702	19,727	22,229	24,678	27,066	29,410	31,710	33,096	34,396	35,597	36,701
Cumulative Surplus Credit Bank Balance	**6,927**	**11,542**	**16,541**	**22,381**	**30,170**	**39,481**	**48,289**	**58,525**	**70,249**	**83,092**	**96,722**	**110,360**	**124,085**	**137,593**	**151,074**	**164,514**	**171,798**	**178,967**	**186,003**	**192,931**
Adjusted Qualifying Renewables																				
Utah	2,950	3,169	3,869	4,518	5,641	6,612	7,434	8,356	9,182	9,910	10,607	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,233
Other (ID,WY)	823	1,024	1,403	1,776	2,384	2,936	3,410	3,952	4,433	4,837	5,237	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,741
California	88	176	185	194	204	220	255	292	324	353	380	398	398	397	397	397	392	387	382	377
Washington	264	300	414	529	732	900	1,069	1,236	1,383	1,516	1,639	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,701
Oregon	983	1,146	1,537	1,923	2,550	3,061	3,513	4,038	4,500	4,935	5,324	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,264
Adjusted Qualifying Renewables	**5,109**	**5,816**	**7,409**	**8,940**	**11,511**	**13,730**	**15,681**	**17,874**	**19,821**	**21,550**	**23,187**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,315**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	16%	20%	23%	26%	29%	31%	34%	36%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

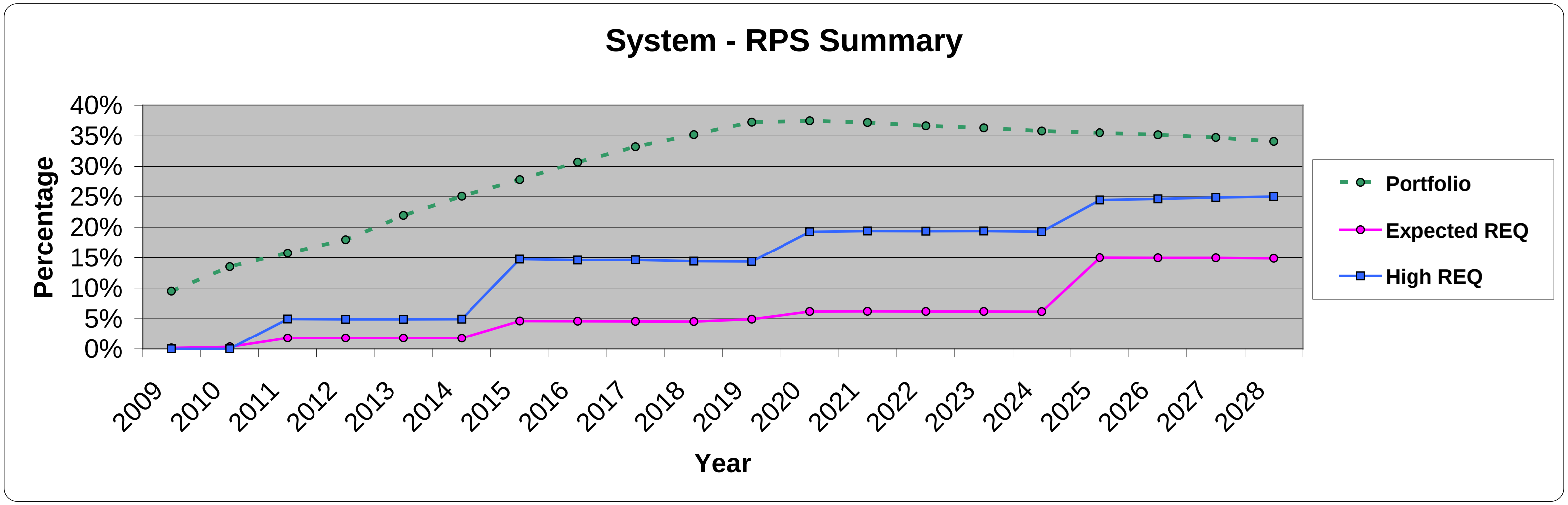


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 27

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,556	9,391	13,836	18,911	25,109	32,261	40,235	49,131	58,806	69,164	80,220	91,467	102,728	113,939	125,164	136,385	142,369	148,329	154,225	160,041
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	422	820	907	1,220	1,587	1,674	1,760	2,060	2,318	2,309	2,201	2,219	2,200	2,184	2,176	2,161	2,141	2,118	2,082
Oregon	1,380	2,934	4,121	5,673	7,838	10,487	12,091	14,203	16,725	19,646	22,934	25,479	27,969	30,399	32,785	35,126	36,554	37,894	39,120	40,209
Cumulative Surplus Credit Bank Balance	**6,936**	**12,746**	**18,776**	**25,491**	**34,166**	**44,336**	**54,000**	**65,094**	**77,591**	**91,129**	**105,463**	**119,146**	**132,916**	**146,538**	**160,133**	**173,687**	**181,084**	**188,364**	**195,463**	**202,333**
Adjusted Qualifying Renewables																				
Utah	2,956	3,834	4,445	5,076	6,197	7,152	7,974	8,896	9,675	10,358	11,055	11,247	11,262	11,211	11,226	11,221	11,241	11,261	11,254	11,207
Other (ID,WY)	826	1,389	1,723	2,088	2,696	3,244	3,720	4,263	4,717	5,095	5,496	5,632	5,647	5,618	5,632	5,581	5,633	5,684	5,718	5,726
California	88	176	185	194	209	242	277	314	344	371	398	401	401	399	400	400	395	389	383	376
Washington	265	422	519	631	833	999	1,168	1,334	1,473	1,598	1,721	1,748	1,747	1,738	1,737	1,736	1,730	1,725	1,714	1,696
Oregon	986	1,554	1,888	2,260	2,885	3,382	3,832	4,356	4,789	5,198	5,588	5,641	5,624	5,583	5,568	5,553	5,489	5,426	5,348	5,249
Adjusted Qualifying Renewables	**5,122**	**7,375**	**8,760**	**10,248**	**12,821**	**15,019**	**16,971**	**19,162**	**20,998**	**22,620**	**24,257**	**24,668**	**24,680**	**24,548**	**24,563**	**24,490**	**24,489**	**24,486**	**24,417**	**24,254**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	37%	37%	37%	36%	36%	36%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

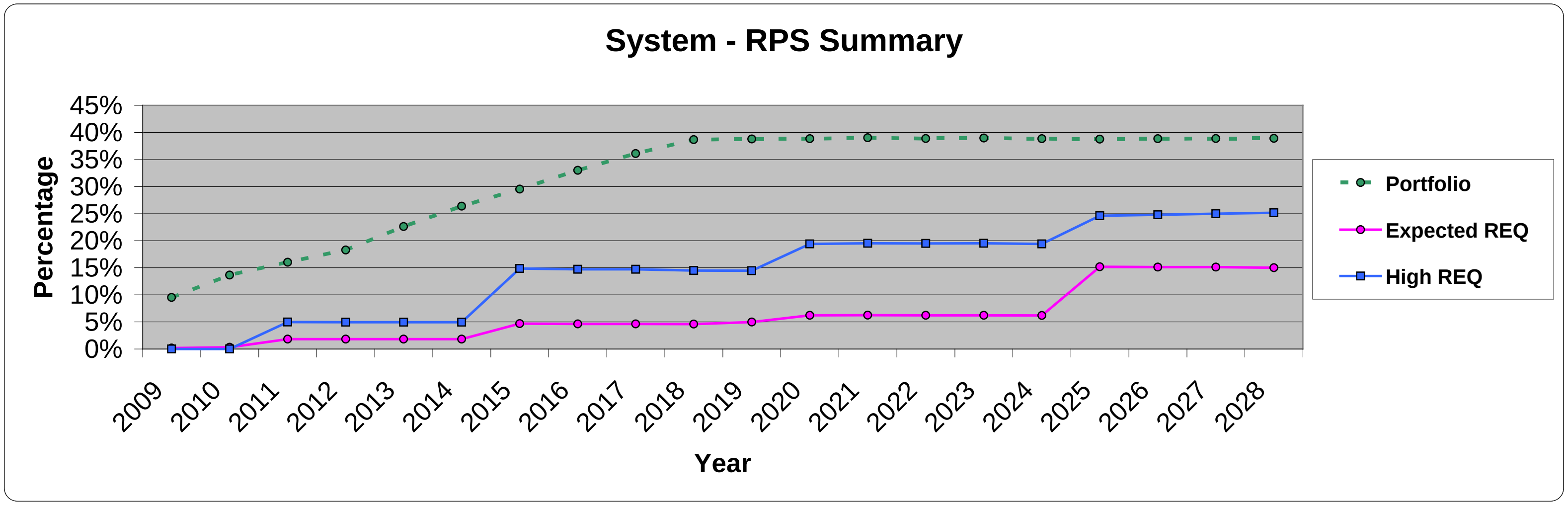


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 28

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,397	13,833	18,863	25,014	32,166	40,140	49,036	58,710	69,067	79,492	89,948	100,418	110,838	121,272	131,702	137,580	143,506	149,455	155,464
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	422	819	899	1,208	1,586	1,695	1,797	2,105	2,372	2,277	2,058	2,060	2,055	2,053	2,059	2,047	2,030	2,025	2,019
Oregon	1,382	2,938	4,126	5,665	7,824	10,503	12,220	14,469	17,154	20,262	23,393	25,795	28,181	30,542	32,896	35,242	36,805	38,331	39,804	41,233
Cumulative Surplus Credit Bank Balance	**6,942**	**12,757**	**18,779**	**25,427**	**34,046**	**44,255**	**54,055**	**65,302**	**77,969**	**91,700**	**105,162**	**117,801**	**130,659**	**143,435**	**156,221**	**169,002**	**176,431**	**183,867**	**191,284**	**198,716**
Adjusted Qualifying Renewables																				
Utah	2,959	3,837	4,436	5,030	6,152	7,152	7,974	8,895	9,674	10,357	10,425	10,456	10,470	10,419	10,434	10,429	10,384	10,405	10,412	10,434
Other (ID,WY)	828	1,391	1,718	2,062	2,670	3,244	3,720	4,262	4,717	5,094	5,132	5,171	5,185	5,156	5,168	5,119	5,128	5,174	5,211	5,256
California	88	176	185	194	207	242	277	314	344	371	373	369	369	368	368	368	361	356	351	346
Washington	266	422	518	622	825	999	1,168	1,334	1,473	1,598	1,606	1,603	1,603	1,593	1,592	1,592	1,574	1,569	1,561	1,555
Oregon	989	1,556	1,882	2,232	2,857	3,382	3,832	4,356	4,789	5,197	5,218	5,180	5,164	5,124	5,110	5,093	4,996	4,939	4,874	4,818
Adjusted Qualifying Renewables	**5,130**	**7,381**	**8,739**	**10,139**	**12,711**	**15,019**	**16,970**	**19,161**	**20,997**	**22,617**	**22,754**	**22,779**	**22,791**	**22,660**	**22,674**	**22,601**	**22,443**	**22,443**	**22,409**	**22,410**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	14%	16%	18%	23%	26%	30%	33%	36%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

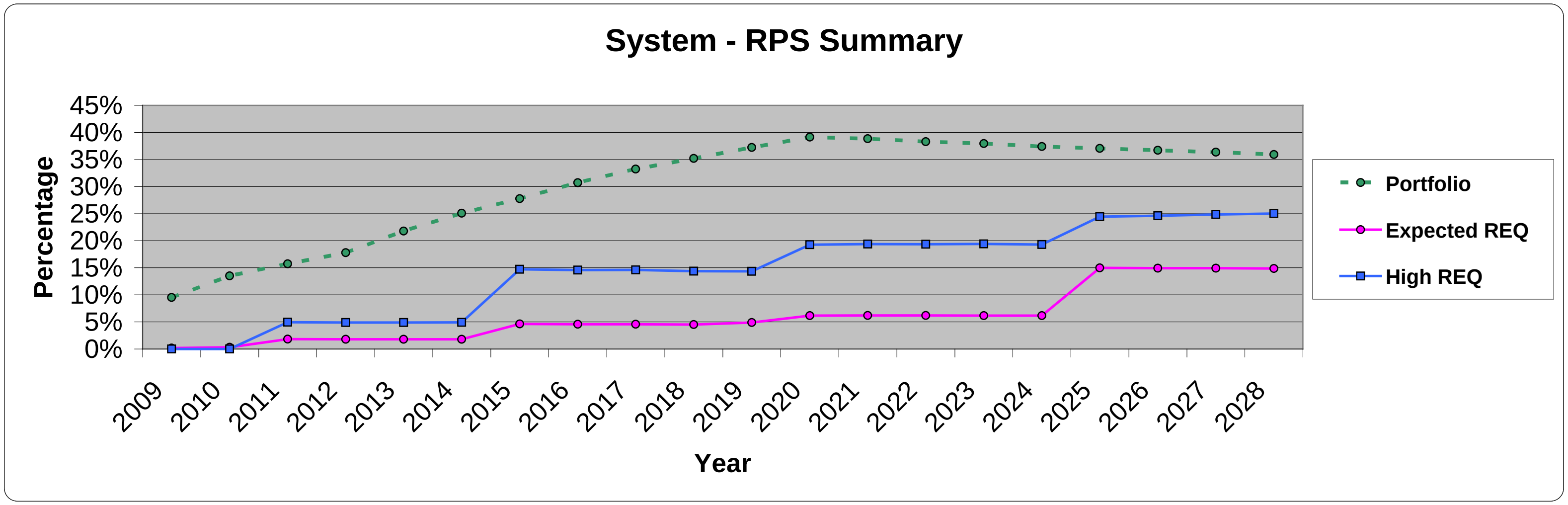


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 29

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,397	13,840	18,881	25,043	32,196	40,170	49,065	58,740	69,097	80,150	91,862	103,588	115,263	126,953	138,638	145,066	151,475	157,849	164,212
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	422	820	900	1,207	1,581	1,674	1,759	2,060	2,318	2,309	2,285	2,388	2,370	2,353	2,345	2,327	2,304	2,287	2,269
Oregon	1,382	2,938	4,124	5,655	7,798	10,448	12,051	14,163	16,686	19,606	22,892	25,708	28,468	31,167	33,822	36,433	38,117	39,712	41,207	42,602
Cumulative Surplus Credit Bank Balance	**6,942**	**12,757**	**18,784**	**25,436**	**34,049**	**44,224**	**53,895**	**64,988**	**77,486**	**91,021**	**105,352**	**119,855**	**134,444**	**148,800**	**163,128**	**177,416**	**185,510**	**193,491**	**201,343**	**209,083**
Adjusted Qualifying Renewables																				
Utah	2,960	3,837	4,443	5,041	6,162	7,152	7,974	8,896	9,675	10,357	11,054	11,711	11,726	11,675	11,690	11,685	11,686	11,710	11,732	11,754
Other (ID,WY)	828	1,391	1,722	2,068	2,676	3,244	3,720	4,263	4,717	5,094	5,495	5,902	5,918	5,889	5,903	5,852	5,896	5,952	6,006	6,059
California	88	176	185	194	208	242	277	314	344	371	398	419	419	418	419	418	412	407	402	397
Washington	266	422	519	624	827	999	1,168	1,334	1,473	1,598	1,720	1,833	1,832	1,822	1,822	1,821	1,812	1,807	1,802	1,796
Oregon	989	1,556	1,887	2,239	2,864	3,382	3,832	4,356	4,789	5,197	5,586	5,911	5,893	5,853	5,837	5,822	5,745	5,681	5,618	5,554
Adjusted Qualifying Renewables	**5,130**	**7,381**	**8,756**	**10,166**	**12,736**	**15,019**	**16,971**	**19,162**	**20,998**	**22,616**	**24,253**	**25,776**	**25,788**	**25,657**	**25,671**	**25,599**	**25,551**	**25,556**	**25,559**	**25,560**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	14%	16%	18%	22%	25%	28%	31%	33%	35%	37%	39%	39%	38%	38%	37%	37%	37%	36%	36%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

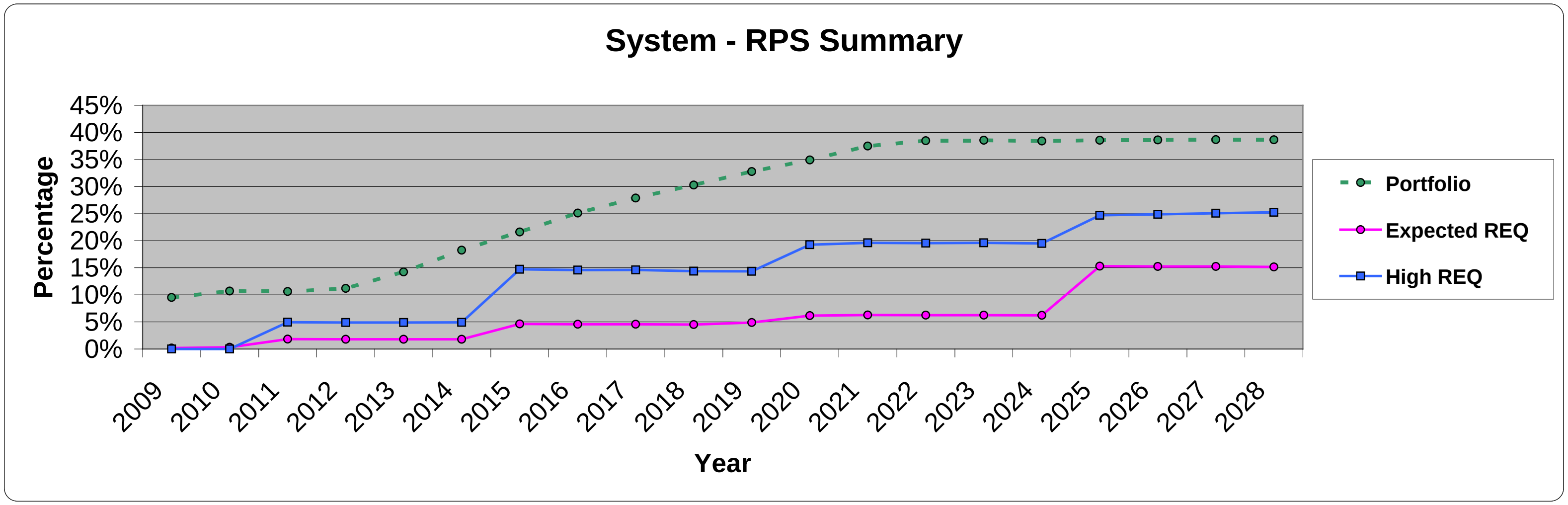


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 30

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,134	5,114	5,105	5,071
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	338	337	337	337	335	334	333
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	640	636	633	630	627	623	619
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,119	3,113	3,106	3,884	3,864	3,853	3,843
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,097	4,086	4,076	9,986	9,939	9,915	9,866
Bank Balance																				
Utah	5,560	8,745	11,975	15,410	19,691	25,112	31,510	38,945	47,207	56,245	66,089	76,636	87,869	99,365	110,877	122,383	128,773	135,206	141,668	148,185
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	385	570	921	1,070	1,205	1,535	1,819	1,847	1,852	2,086	2,251	2,302	2,308	2,307	2,302	2,299	2,295
Oregon	1,382	2,537	2,986	3,545	4,558	6,178	6,851	8,103	9,797	11,941	14,518	16,654	19,128	21,758	24,379	26,992	28,760	30,485	32,156	33,775
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**15,441**	**19,341**	**24,820**	**32,212**	**39,431**	**48,253**	**58,539**	**70,005**	**82,454**	**95,142**	**109,083**	**123,374**	**137,558**	**151,682**	**159,840**	**167,992**	**176,123**	**184,256**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,231	3,435	4,282	5,421	6,398	7,435	8,262	9,038	9,844	10,547	11,233	11,496	11,511	11,506	11,525	11,546	11,567	11,588
Other (ID,WY)	828	1,033	1,049	1,171	1,619	2,257	2,816	3,422	3,901	4,334	4,797	5,224	5,630	5,785	5,799	5,748	5,801	5,854	5,907	5,958
California	88	176	185	194	204	213	223	255	287	318	349	373	400	411	411	411	406	401	395	390
Washington	266	303	298	331	483	683	880	1,068	1,215	1,357	1,500	1,620	1,742	1,790	1,789	1,788	1,782	1,777	1,771	1,766
Oregon	989	1,155	1,149	1,267	1,733	2,353	2,901	3,496	3,960	4,422	4,877	5,232	5,607	5,749	5,734	5,718	5,652	5,588	5,525	5,462
Adjusted Qualifying Renewables	**5,131**	**5,852**	**5,911**	**6,397**	**8,320**	**10,927**	**13,217**	**15,676**	**17,626**	**19,468**	**21,367**	**22,996**	**24,612**	**25,230**	**25,244**	**25,172**	**25,167**	**25,166**	**25,165**	**25,164**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	65,679	65,596	65,504	65,544	65,302	65,191	65,074	65,105
Portfolio	10%	11%	11%	11%	14%	18%	22%	25%	28%	30%	33%	35%	37%	38%	39%	38%	39%	39%	39%	39%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

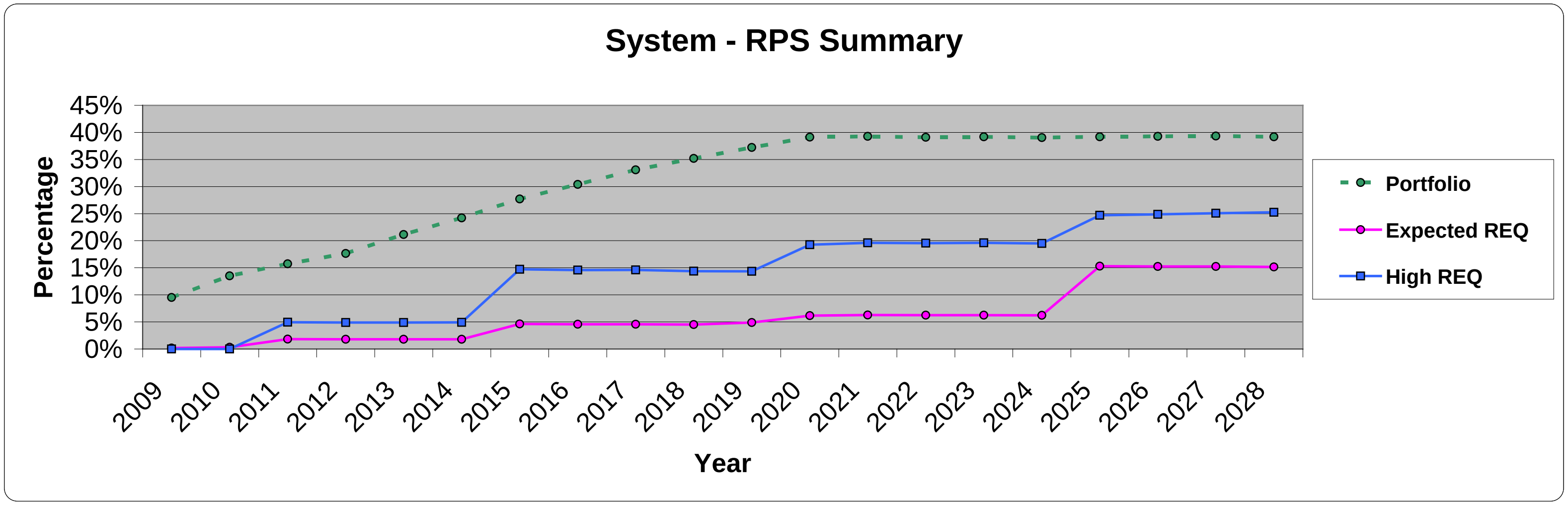


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45 (2013) to $179 (2030) 1/, Gas = Medium - June 2008, Load Growth = Medium (2009-2020)□Low (2021-2030), Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 31

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,134	5,114	5,105	5,071
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	338	337	337	337	335	334	333
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	640	636	633	630	627	623	619
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,119	3,113	3,106	3,884	3,864	3,853	3,843
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,097	4,086	4,076	9,986	9,939	9,915	9,866
Bank Balance																				
Utah	5,560	9,399	13,842	18,845	24,852	31,792	39,753	48,569	58,206	68,564	79,620	91,331	103,057	114,732	126,422	138,107	144,678	151,291	157,932	164,593
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	423	820	893	1,172	1,514	1,633	1,743	2,038	2,311	2,309	2,286	2,388	2,373	2,367	2,373	2,373	2,368	2,364	2,354
Oregon	1,382	2,939	4,125	5,633	7,683	10,206	11,802	13,867	16,368	19,289	22,576	25,392	28,152	30,885	33,610	36,326	38,198	40,025	41,798	43,497
Cumulative Surplus Credit Bank Balance	**6,942**	**12,761**	**18,787**	**25,371**	**33,708**	**43,512**	**53,188**	**64,179**	**76,612**	**90,164**	**104,505**	**119,008**	**133,597**	**147,991**	**162,399**	**176,806**	**185,249**	**193,684**	**202,094**	**210,444**
Adjusted Qualifying Renewables																				
Utah	2,960	3,839	4,443	5,003	6,007	6,940	7,961	8,816	9,637	10,358	11,055	11,711	11,726	11,675	11,690	11,685	11,705	11,726	11,746	11,732
Other (ID,WY)	828	1,392	1,722	2,047	2,589	3,123	3,712	4,217	4,695	5,095	5,496	5,902	5,918	5,889	5,903	5,852	5,907	5,962	6,014	6,045
California	88	176	185	194	204	234	277	310	342	371	398	419	419	418	419	418	413	408	402	396
Washington	266	423	519	617	798	960	1,165	1,320	1,466	1,598	1,721	1,833	1,832	1,822	1,822	1,821	1,815	1,810	1,804	1,792
Oregon	989	1,557	1,886	2,216	2,771	3,256	3,824	4,309	4,767	5,198	5,588	5,911	5,893	5,853	5,837	5,822	5,756	5,691	5,626	5,542
Adjusted Qualifying Renewables	**5,131**	**7,386**	**8,755**	**10,077**	**12,369**	**14,512**	**16,939**	**18,973**	**20,907**	**22,620**	**24,257**	**25,776**	**25,788**	**25,657**	**25,671**	**25,599**	**25,597**	**25,596**	**25,593**	**25,507**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	65,679	65,596	65,504	65,544	65,302	65,191	65,074	65,105
Portfolio	10%	14%	16%	18%	21%	24%	28%	30%	33%	35%	37%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

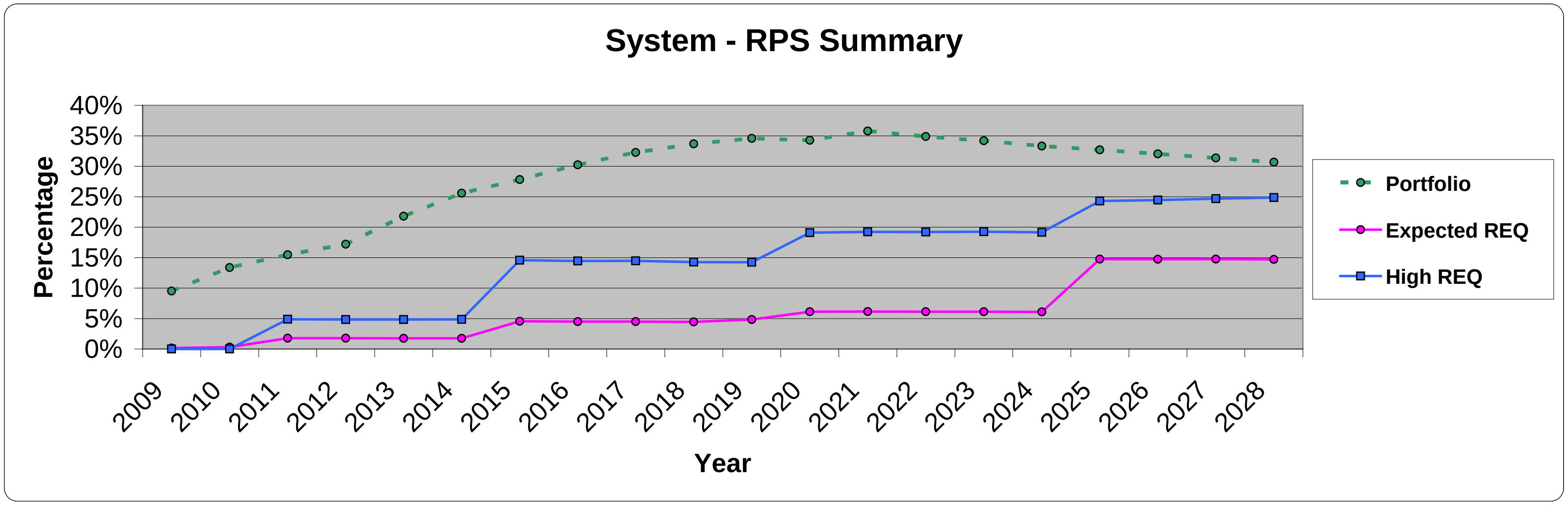


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45 (2013) to $179 (2030) 1/, Gas = High - June 2008, Load Growth = Medium (2009-2020)□Low (2021-2030), Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 33

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,560	9,398	13,854	18,879	25,263	32,877	41,311	50,668	60,819	71,652	83,020	94,535	106,738	118,889	131,056	143,218	149,297	155,267	161,108	166,844
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	423	822	897	1,240	1,698	1,820	1,888	2,183	2,435	2,364	2,181	2,297	2,385	2,351	2,325	2,292	2,253	2,215	2,178
Oregon	1,382	2,938	4,125	5,632	7,887	10,780	12,538	14,776	17,406	20,405	23,645	25,998	28,643	31,184	33,635	35,996	37,245	38,340	39,267	40,025
Cumulative Surplus Credit Bank Balance	**6,941**	**12,759**	**18,800**	**25,408**	**34,390**	**45,355**	**55,670**	**67,332**	**80,408**	**94,493**	**109,029**	**122,714**	**137,678**	**152,458**	**167,042**	**181,539**	**188,833**	**195,859**	**202,590**	**209,047**
Adjusted Qualifying Renewables																				
Utah	2,959	3,838	4,456	5,025	6,384	7,614	8,435	9,356	10,151	10,833	11,368	11,515	12,203	12,151	12,167	12,162	12,182	12,203	12,224	12,246
Other (ID,WY)	828	1,391	1,729	2,060	2,801	3,507	3,984	4,528	4,993	5,369	5,676	5,788	6,196	6,167	6,183	6,131	6,189	6,246	6,302	6,358
California	88	176	185	194	217	261	296	332	363	390	411	412	438	437	438	437	432	426	428	436
Washington	266	423	521	622	867	1,083	1,252	1,418	1,560	1,685	1,778	1,797	1,919	1,909	1,909	1,908	1,902	1,897	1,891	1,886
Oregon	988	1,556	1,894	2,229	2,997	3,656	4,104	4,627	5,069	5,478	5,771	5,797	6,170	6,129	6,113	6,099	6,030	5,962	5,895	5,829
Adjusted Qualifying Renewables	**5,130**	**7,384**	**8,785**	**10,130**	**13,267**	**16,120**	**18,070**	**20,261**	**22,136**	**23,754**	**25,003**	**25,309**	**26,926**	**26,795**	**26,809**	**26,736**	**26,735**	**26,734**	**26,740**	**26,754**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	10%	13%	15%	17%	22%	26%	28%	30%	32%	34%	35%	34%	36%	35%	34%	33%	33%	32%	31%	31%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



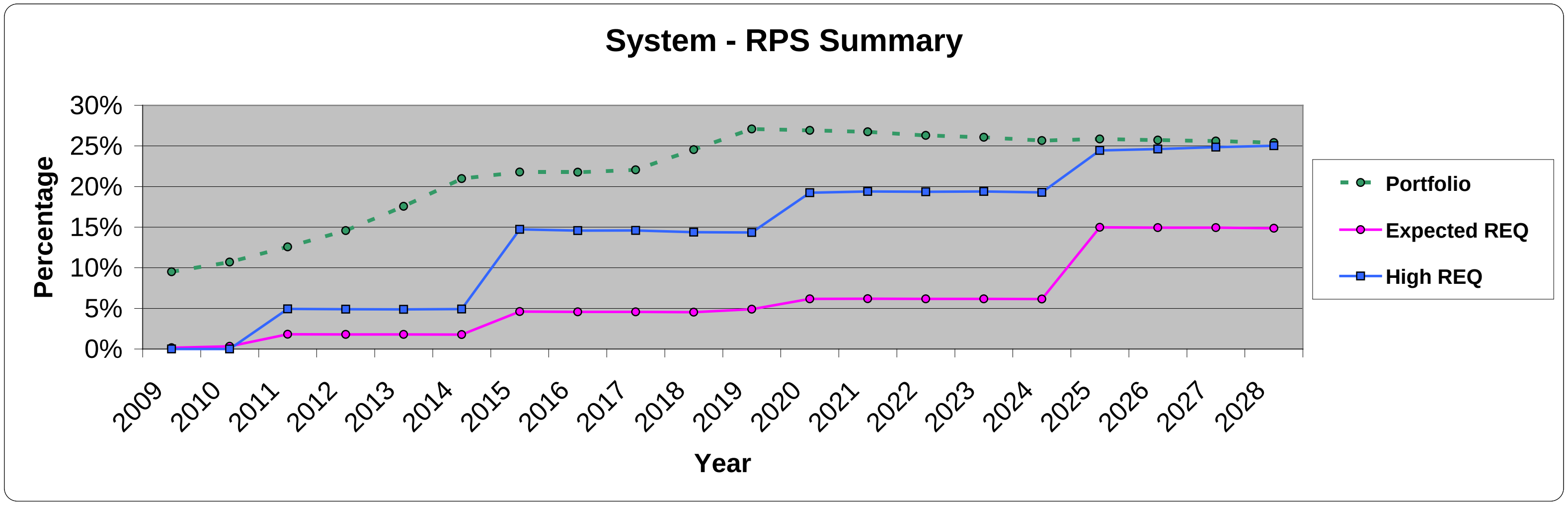
System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - June 2008, Load Growth = High, Renewable Std = Base, Baseload Plant Avail = Late, Plant Cost = High, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 34

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,745	12,437	16,695	21,812	27,935	34,378	40,933	47,647	55,137	63,428	71,749	80,085	88,369	96,669	104,964	108,021	111,057	114,056	117,043
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	564	620	873	1,202	1,207	1,053	1,091	1,254	1,281	1,162	1,150	1,132	1,115	1,107	1,092	1,073	1,055	1,037
Oregon	1,382	2,537	3,267	4,324	5,839	7,877	8,576	9,310	10,096	11,330	12,995	13,834	14,624	15,356	16,048	16,690	16,436	16,111	15,705	15,217
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**16,268**	**21,640**	**28,523**	**37,013**	**44,161**	**51,296**	**58,834**	**67,721**	**77,704**	**86,745**	**95,859**	**104,857**	**113,832**	**122,761**	**125,550**	**128,241**	**130,815**	**133,297**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,693	4,258	5,116	6,123	6,444	6,555	6,714	7,490	8,291	8,321	8,336	8,285	8,300	8,295	8,315	8,336	8,357	8,379
Other (ID,WY)	828	1,033	1,305	1,631	2,088	2,657	2,842	2,914	3,006	3,442	3,899	3,929	3,939	3,909	3,918	3,873	3,907	3,940	3,973	4,005
California	88	176	185	194	204	213	223	233	243	256	287	336	339	341	345	348	352	354	357	360
Washington	266	303	382	481	636	811	888	907	932	1,074	1,216	1,213	1,213	1,203	1,203	1,202	1,196	1,191	1,185	1,180
Oregon	989	1,155	1,430	1,765	2,235	2,770	2,928	2,978	3,052	3,512	3,965	3,935	3,923	3,885	3,874	3,853	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**5,852**	**6,995**	**8,330**	**10,279**	**12,575**	**13,325**	**13,587**	**13,947**	**15,774**	**17,658**	**17,735**	**17,750**	**17,623**	**17,640**	**17,571**	**17,831**	**17,907**	**17,995**	**18,083**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	13%	15%	18%	21%	22%	22%	22%	25%	27%	27%	27%	26%	26%	26%	26%	26%	26%	25%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

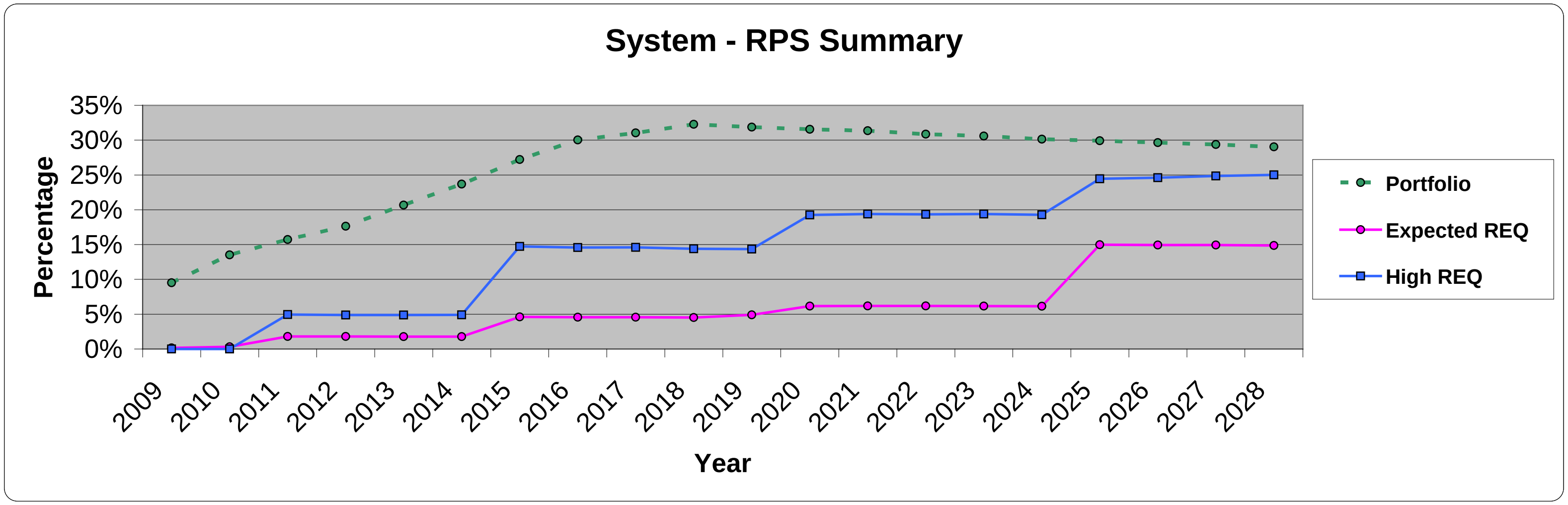


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 35

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,399	13,842	18,845	24,733	31,541	39,378	48,098	57,196	66,766	76,361	85,986	95,625	105,214	114,817	124,416	128,778	133,117	137,420	141,712
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	423	820	893	1,150	1,468	1,586	1,702	1,922	2,069	1,899	1,638	1,626	1,608	1,591	1,583	1,568	1,549	1,531	1,513
Oregon	1,382	2,939	4,125	5,633	7,612	10,056	11,579	13,588	15,772	18,229	20,659	22,259	23,806	25,294	26,742	28,141	28,637	29,054	29,382	29,621
Cumulative Surplus Credit Bank Balance	**6,942**	**12,761**	**18,788**	**25,371**	**33,495**	**43,065**	**52,544**	**63,388**	**74,890**	**87,064**	**98,918**	**109,882**	**121,058**	**132,116**	**143,150**	**154,140**	**158,983**	**163,719**	**168,333**	**172,846**
Adjusted Qualifying Renewables																				
Utah	2,960	3,839	4,443	5,003	5,888	6,808	7,838	8,720	9,097	9,570	9,595	9,625	9,640	9,588	9,604	9,599	9,619	9,640	9,661	9,683
Other (ID,WY)	828	1,392	1,722	2,047	2,522	3,047	3,641	4,161	4,384	4,641	4,652	4,688	4,700	4,670	4,682	4,635	4,676	4,718	4,758	4,798
California	88	176	185	194	204	228	272	307	321	339	339	336	339	341	345	348	352	354	357	360
Washington	266	423	519	617	777	936	1,143	1,302	1,368	1,454	1,454	1,452	1,451	1,441	1,441	1,440	1,434	1,429	1,423	1,418
Oregon	989	1,557	1,887	2,215	2,699	3,177	3,751	4,252	4,451	4,735	4,730	4,695	4,681	4,642	4,629	4,611	4,557	4,504	4,451	4,399
Adjusted Qualifying Renewables	**5,131**	**7,386**	**8,756**	**10,076**	**12,090**	**14,197**	**16,644**	**18,742**	**19,620**	**20,739**	**20,770**	**20,796**	**20,811**	**20,683**	**20,700**	**20,631**	**20,638**	**20,644**	**20,651**	**20,658**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	14%	16%	18%	21%	24%	27%	30%	31%	32%	32%	32%	31%	31%	31%	30%	30%	30%	29%	29%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

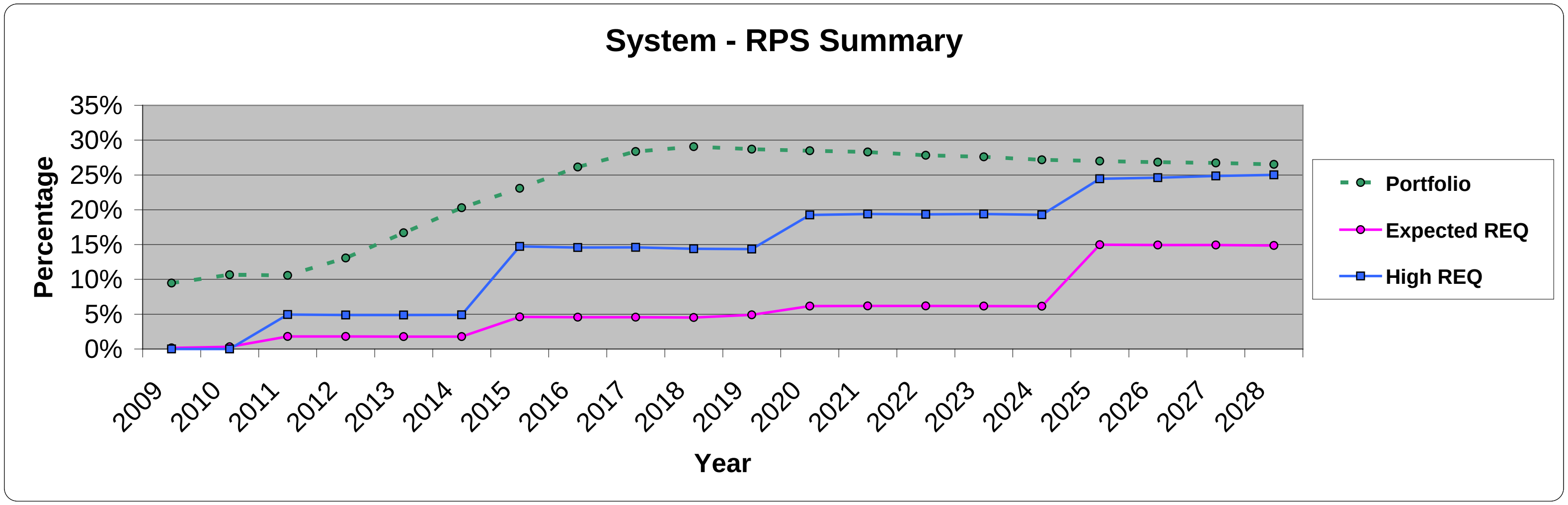


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 36

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,553	8,728	11,951	15,840	20,737	26,683	33,459	41,159	49,547	58,253	66,983	75,744	84,520	93,244	101,984	110,718	114,216	117,691	121,130	124,557
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	302	476	467	766	1,129	1,235	1,322	1,606	1,782	1,583	1,322	1,311	1,292	1,276	1,268	1,253	1,233	1,215	1,197
Oregon	1,378	2,527	2,971	3,805	5,188	7,120	8,016	9,424	11,192	13,141	15,064	16,160	17,206	18,192	19,139	20,037	20,036	19,961	19,802	19,559
Cumulative Surplus Credit Bank Balance	**6,931**	**11,557**	**15,398**	**20,112**	**26,690**	**34,932**	**42,711**	**51,906**	**62,345**	**73,176**	**83,631**	**93,227**	**103,036**	**112,729**	**122,398**	**132,023**	**135,504**	**138,885**	**142,147**	**145,314**
Adjusted Qualifying Renewables																				
Utah	2,953	3,175	3,223	3,889	4,897	5,946	6,777	7,699	8,388	8,706	8,731	8,761	8,775	8,724	8,740	8,734	8,755	8,776	8,797	8,818
Other (ID,WY)	824	1,028	1,044	1,425	1,965	2,556	3,033	3,574	3,974	4,143	4,153	4,185	4,196	4,166	4,176	4,130	4,167	4,203	4,238	4,273
California	88	176	185	194	204	213	229	266	292	305	305	336	339	341	345	348	352	354	357	360
Washington	265	302	296	414	596	779	949	1,116	1,238	1,296	1,296	1,294	1,293	1,283	1,283	1,282	1,276	1,271	1,266	1,260
Oregon	984	1,149	1,144	1,542	2,102	2,665	3,124	3,652	4,034	4,227	4,223	4,192	4,179	4,140	4,129	4,109	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,114**	**5,830**	**5,892**	**7,464**	**9,763**	**12,159**	**14,112**	**16,306**	**17,927**	**18,676**	**18,708**	**18,767**	**18,782**	**18,655**	**18,672**	**18,603**	**18,611**	**18,690**	**18,780**	**18,871**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	20%	23%	26%	28%	29%	29%	28%	28%	28%	28%	27%	27%	27%	27%	27%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

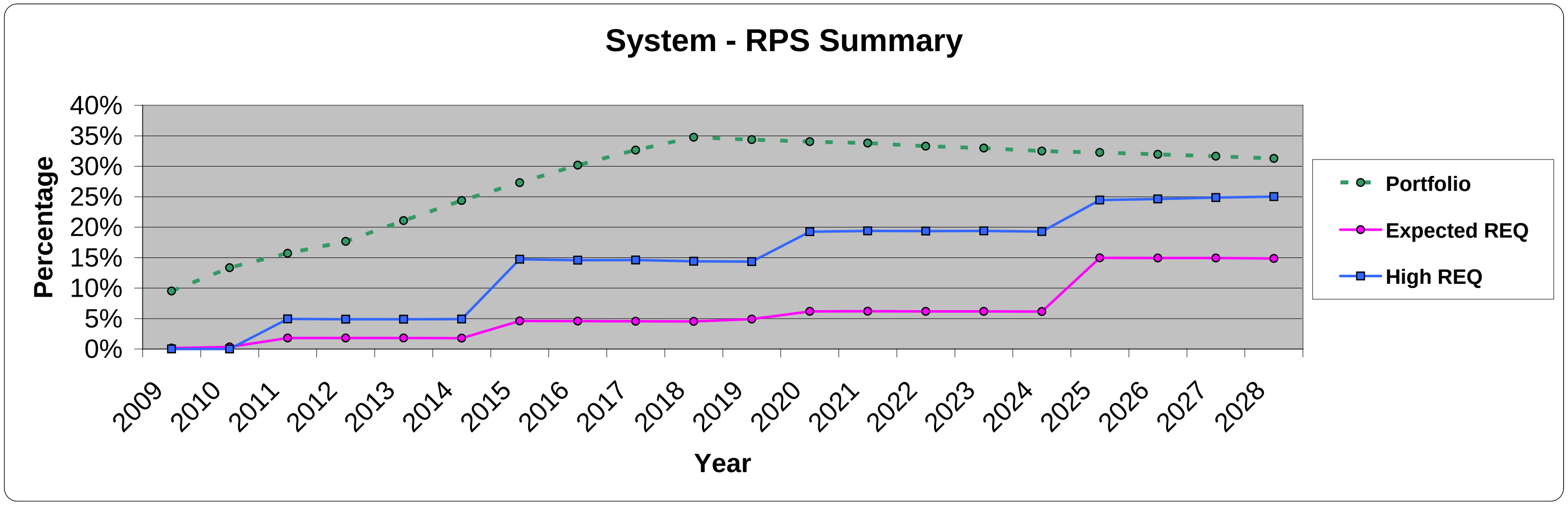


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 37

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,357	13,797	18,803	24,792	31,773	39,629	48,386	57,907	68,148	78,424	88,731	99,053	109,324	119,609	129,890	134,933	139,955	144,940	149,913
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	812	893	1,169	1,518	1,621	1,713	2,006	2,269	2,146	1,887	1,875	1,857	1,840	1,832	1,817	1,798	1,780	1,762
Oregon	1,382	2,913	4,097	5,607	7,646	10,194	11,728	13,758	16,191	19,042	21,873	23,870	25,814	27,698	29,540	31,335	32,223	33,028	33,741	34,360
Cumulative Surplus Credit Bank Balance	**6,942**	**12,685**	**18,705**	**25,304**	**33,608**	**43,485**	**52,979**	**63,857**	**76,104**	**89,459**	**102,443**	**114,488**	**126,742**	**138,878**	**150,989**	**163,057**	**168,974**	**174,781**	**180,460**	**186,036**
Adjusted Qualifying Renewables																				
Utah	2,960	3,797	4,440	5,007	5,989	6,981	7,857	8,756	9,521	10,241	10,277	10,307	10,322	10,270	10,286	10,281	10,301	10,322	10,343	10,365
Other (ID,WY)	828	1,369	1,720	2,049	2,579	3,146	3,652	4,182	4,629	5,027	5,046	5,085	5,098	5,069	5,081	5,033	5,079	5,124	5,169	5,213
California	88	176	185	194	204	235	272	308	338	366	367	363	363	362	362	362	357	354	357	360
Washington	266	415	518	618	795	968	1,146	1,309	1,445	1,576	1,579	1,576	1,575	1,566	1,565	1,564	1,559	1,553	1,548	1,542
Oregon	989	1,531	1,884	2,218	2,759	3,280	3,763	4,274	4,699	5,129	5,130	5,093	5,077	5,038	5,024	5,007	4,949	4,892	4,835	4,779
Adjusted Qualifying Renewables	**5,131**	**7,287**	**8,747**	**10,086**	**12,325**	**14,610**	**16,690**	**18,830**	**20,631**	**22,340**	**22,398**	**22,424**	**22,436**	**22,304**	**22,319**	**22,246**	**22,245**	**22,245**	**22,252**	**22,260**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	21%	24%	27%	30%	33%	35%	34%	34%	34%	33%	33%	32%	32%	32%	32%	31%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

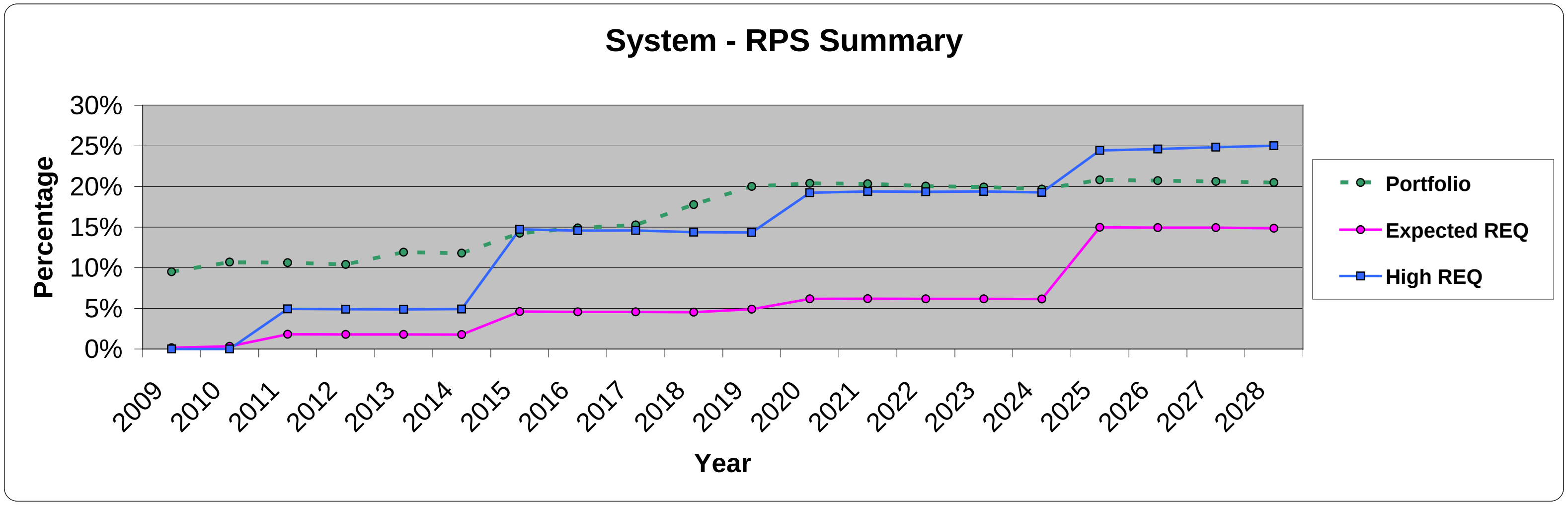


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 38

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,745	11,978	15,219	18,925	22,700	26,917	31,449	36,167	41,805	48,139	54,502	60,881	67,208	73,550	79,887	80,988	82,066	83,107	84,138
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	480	351	430	516	371	277	358	551	585	447	435	417	400	392	377	358	340	322
Oregon	1,382	2,537	2,987	3,430	4,096	4,739	4,122	3,667	3,282	3,427	3,943	3,641	3,294	2,889	2,448	1,954	574	-	-	-
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**15,444**	**19,000**	**23,451**	**27,954**	**31,410**	**35,392**	**39,806**	**45,784**	**52,667**	**58,591**	**64,610**	**70,513**	**76,398**	**82,233**	**81,939**	**82,423**	**83,447**	**84,460**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,233	3,242	3,705	3,775	4,217	4,532	4,718	5,639	6,333	6,364	6,378	6,327	6,342	6,337	6,358	6,379	6,400	6,421
Other (ID,WY)	828	1,033	1,050	1,063	1,295	1,319	1,565	1,750	1,853	2,375	2,769	2,790	2,797	2,766	2,772	2,731	2,752	2,773	2,794	2,814
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	378	382	482	537	568	736	858	856	855	846	845	844	839	833	828	822
Oregon	989	1,155	1,150	1,151	1,386	1,375	2,228	2,244	2,266	2,423	2,816	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**5,852**	**5,916**	**5,945**	**6,969**	**7,066**	**8,714**	**9,297**	**9,648**	**11,425**	**13,040**	**13,441**	**13,503**	**13,434**	**13,487**	**13,471**	**14,362**	**14,425**	**14,501**	**14,577**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	12%	12%	14%	15%	15%	18%	20%	20%	20%	20%	20%	20%	21%	21%	21%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

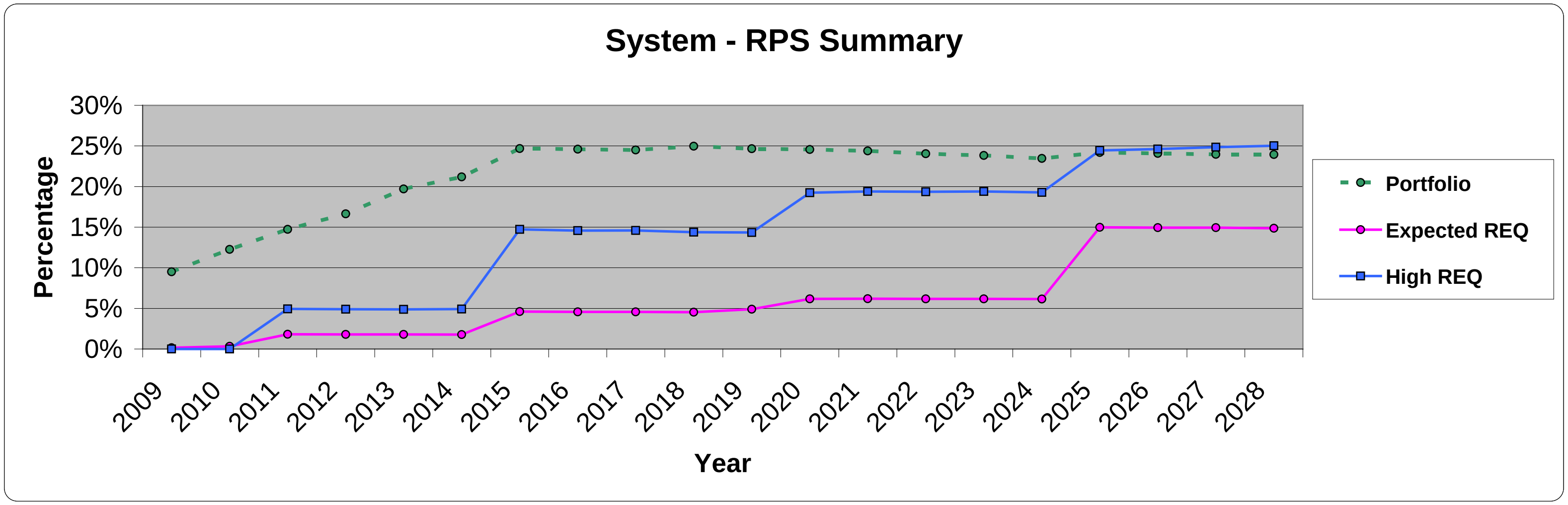


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = High, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 39

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,108	13,316	18,076	23,725	29,902	37,090	44,389	51,755	59,358	66,985	74,642	82,314	89,954	97,610	105,260	107,674	110,065	112,420	114,823
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	370	724	806	1,062	1,309	1,352	1,324	1,346	1,394	1,180	919	908	893	880	872	857	837	819	812
Oregon	1,382	2,760	3,803	5,164	6,999	9,069	10,209	11,381	12,549	13,849	15,124	15,577	15,981	16,339	16,658	16,926	16,302	15,610	14,840	14,026
Cumulative Surplus Credit Bank Balance	**6,941**	**12,238**	**17,844**	**24,045**	**31,786**	**40,281**	**48,651**	**57,095**	**65,651**	**74,601**	**83,289**	**91,139**	**99,203**	**107,186**	**115,147**	**123,058**	**124,832**	**126,512**	**128,079**	**129,661**
Adjusted Qualifying Renewables																				
Utah	2,959	3,548	4,208	4,759	5,649	6,177	7,188	7,299	7,366	7,603	7,627	7,657	7,672	7,640	7,655	7,650	7,671	7,692	7,713	7,794
Other (ID,WY)	828	1,232	1,591	1,911	2,388	2,688	3,269	3,343	3,383	3,507	3,516	3,543	3,552	3,533	3,541	3,497	3,527	3,556	3,585	3,649
California	88	176	185	194	204	213	246	250	251	260	263	336	339	341	345	348	352	354	357	360
Washington	266	370	476	573	733	821	1,024	1,043	1,051	1,095	1,095	1,092	1,092	1,086	1,085	1,084	1,078	1,073	1,068	1,073
Oregon	988	1,379	1,743	2,068	2,555	2,803	3,368	3,416	3,435	3,578	3,575	3,549	3,538	3,511	3,501	3,479	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**6,705**	**8,204**	**9,505**	**11,530**	**12,702**	**15,095**	**15,350**	**15,487**	**16,042**	**16,076**	**16,177**	**16,192**	**16,111**	**16,128**	**16,059**	**16,689**	**16,761**	**16,845**	**17,036**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	12%	15%	17%	20%	21%	25%	25%	24%	25%	25%	25%	24%	24%	24%	23%	24%	24%	24%	24%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

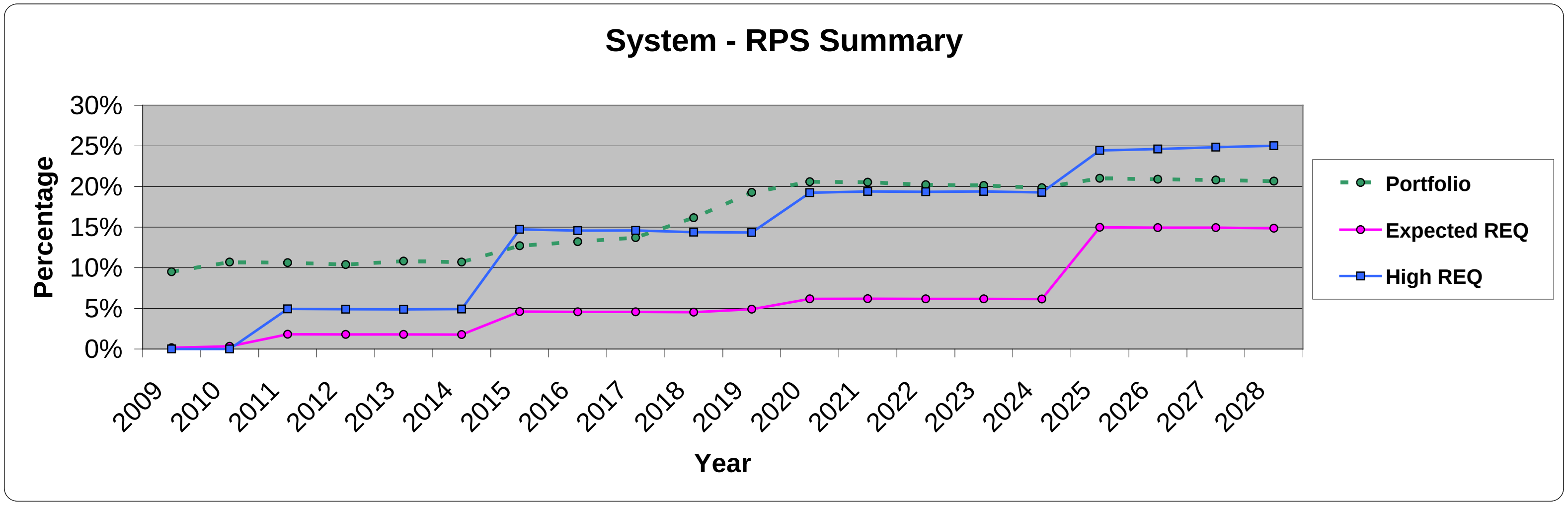


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = High, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 40

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,743	11,975	15,216	18,646	22,145	25,822	29,757	33,915	39,042	45,175	51,612	58,062	64,462	70,877	77,287	78,459	79,610	80,724	81,827
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	350	380	415	222	69	146	356	455	424	462	443	427	419	404	384	366	348
Oregon	1,382	2,536	2,985	3,428	3,928	4,407	3,472	2,664	1,951	1,796	2,194	1,935	1,629	1,267	867	415	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,941**	**11,583**	**15,439**	**18,994**	**22,954**	**26,967**	**29,517**	**32,490**	**36,013**	**41,194**	**47,825**	**53,970**	**60,153**	**66,172**	**72,171**	**78,121**	**78,863**	**79,994**	**81,090**	**82,175**
Adjusted Qualifying Renewables																				
Utah	2,959	3,184	3,231	3,241	3,430	3,499	3,677	3,934	4,158	5,127	6,133	6,436	6,451	6,400	6,415	6,410	6,430	6,451	6,472	6,494
Other (ID,WY)	828	1,032	1,049	1,063	1,141	1,162	1,255	1,405	1,530	2,080	2,654	2,832	2,839	2,808	2,815	2,773	2,795	2,817	2,838	2,858
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	328	332	383	428	466	643	822	869	869	859	858	857	852	846	841	836
Oregon	988	1,155	1,149	1,150	1,220	1,211	2,228	2,244	2,266	2,277	2,698	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,129**	**5,850**	**5,912**	**5,945**	**6,322**	**6,418**	**7,767**	**8,245**	**8,663**	**10,380**	**12,570**	**13,569**	**13,631**	**13,562**	**13,615**	**13,599**	**14,490**	**14,554**	**14,630**	**14,707**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	11%	11%	13%	13%	14%	16%	19%	21%	21%	20%	20%	20%	21%	21%	21%	21%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

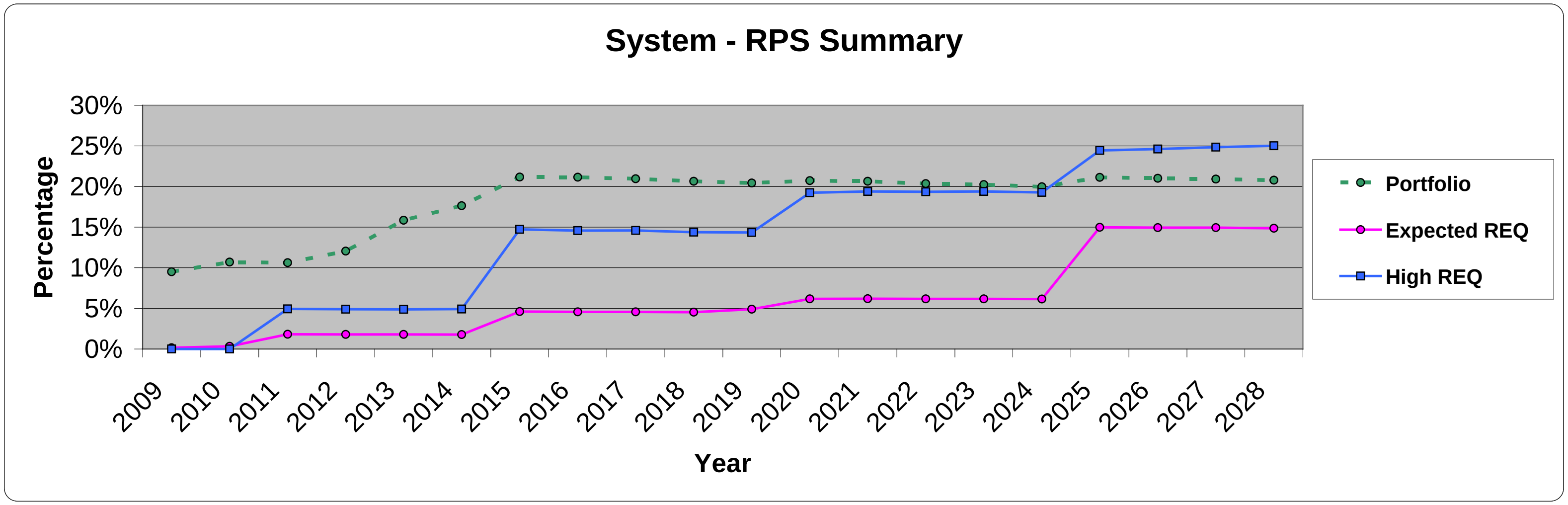


Study Description

CO2 Type = Hard Cap 3/, CO2 Cost = N/A, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 41

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,742	11,973	15,614	20,302	25,571	31,852	38,243	44,659	51,086	57,537	64,019	70,516	76,961	83,421	89,877	91,095	92,291	93,451	94,600
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	423	682	968	1,021	993	1,007	1,005	751	490	478	460	443	435	420	401	383	365
Oregon	1,382	2,536	2,984	3,669	4,926	6,456	7,059	7,697	8,308	8,917	9,502	9,270	8,991	8,655	8,282	7,856	6,545	5,173	3,730	2,216
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,436**	**19,706**	**25,910**	**32,996**	**39,932**	**46,933**	**53,974**	**61,008**	**67,790**	**73,779**	**79,985**	**86,075**	**92,147**	**98,168**	**98,061**	**97,865**	**97,565**	**97,181**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,641	4,688	5,269	6,280	6,391	6,415	6,427	6,452	6,482	6,496	6,445	6,461	6,455	6,476	6,497	6,518	6,539
Other (ID,WY)	828	1,031	1,049	1,286	1,848	2,171	2,748	2,820	2,834	2,829	2,838	2,859	2,866	2,835	2,842	2,800	2,822	2,844	2,865	2,886
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	369	558	655	859	877	878	880	880	878	877	867	867	866	860	855	849	844
Oregon	989	1,154	1,149	1,392	1,977	2,263	2,831	2,882	2,877	2,886	2,885	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**6,882**	**9,274**	**10,572**	**12,942**	**13,203**	**13,248**	**13,275**	**13,317**	**13,650**	**13,712**	**13,642**	**13,696**	**13,680**	**14,571**	**14,636**	**14,712**	**14,789**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	16%	18%	21%	21%	21%	21%	20%	21%	21%	20%	20%	20%	21%	21%	21%	21%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

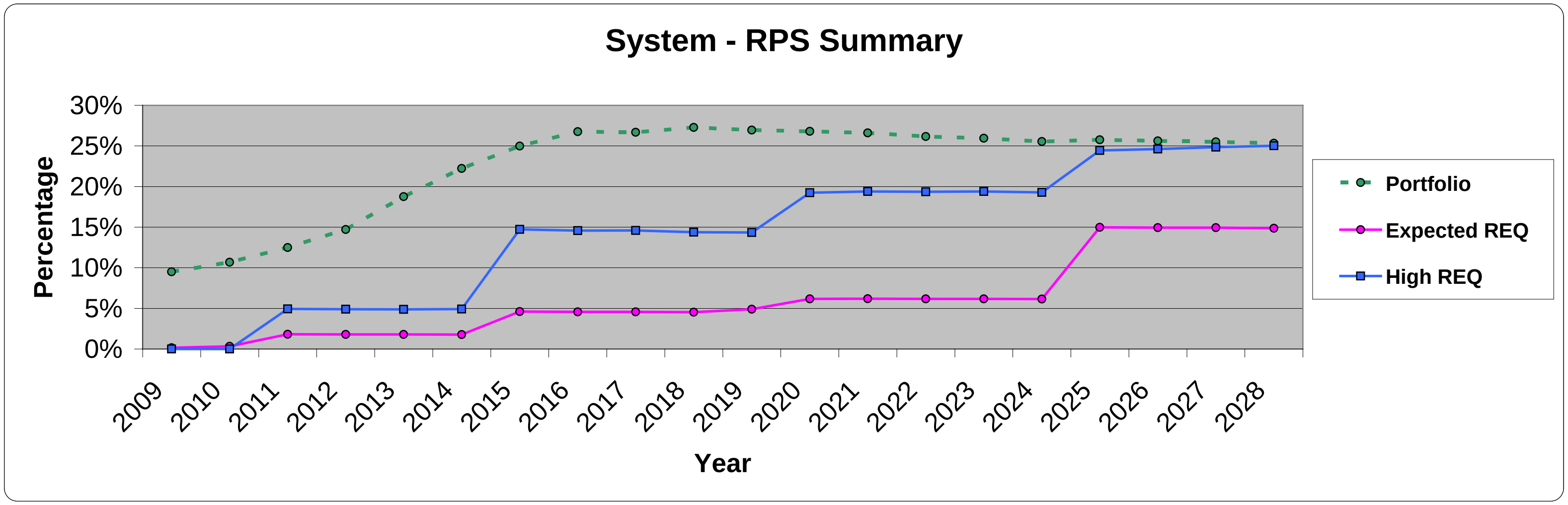


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 15%, Class 3 DSM = Excluded

System - RPS Report - Case # 42

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,741	12,419	16,712	22,126	28,565	35,829	43,696	51,642	59,872	68,126	76,411	84,710	92,958	101,222	109,480	112,501	115,501	118,463	121,415
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	560	624	934	1,314	1,414	1,442	1,556	1,614	1,409	1,149	1,137	1,118	1,102	1,094	1,079	1,059	1,041	1,024
Oregon	1,382	2,535	3,256	4,334	6,028	8,253	9,438	10,944	12,453	14,122	15,765	16,583	17,352	18,062	18,734	19,355	19,080	18,734	18,307	17,799
Cumulative Surplus Credit Bank Balance	**6,942**	**11,579**	**16,235**	**21,671**	**29,087**	**38,132**	**46,681**	**56,083**	**65,650**	**75,607**	**85,300**	**94,143**	**103,199**	**112,139**	**121,057**	**129,929**	**132,660**	**135,294**	**137,812**	**140,237**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,678	4,293	5,413	6,439	7,265	7,867	7,945	8,230	8,254	8,285	8,299	8,248	8,263	8,258	8,279	8,300	8,321	8,342
Other (ID,WY)	828	1,031	1,297	1,650	2,255	2,837	3,313	3,670	3,718	3,868	3,878	3,908	3,918	3,888	3,897	3,852	3,886	3,919	3,951	3,983
California	88	176	185	194	204	213	249	272	275	286	286	336	339	341	345	348	352	354	357	360
Washington	266	303	379	488	690	869	1,038	1,146	1,157	1,209	1,209	1,207	1,206	1,197	1,196	1,195	1,190	1,184	1,179	1,173
Oregon	989	1,153	1,421	1,786	2,413	2,958	3,413	3,750	3,775	3,947	3,943	3,914	3,902	3,864	3,853	3,832	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,844**	**6,960**	**8,412**	**10,976**	**13,316**	**15,277**	**16,706**	**16,870**	**17,540**	**17,571**	**17,649**	**17,665**	**17,538**	**17,555**	**17,486**	**17,767**	**17,843**	**17,930**	**18,018**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	13%	15%	19%	22%	25%	27%	27%	27%	27%	27%	27%	26%	26%	26%	26%	26%	26%	25%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

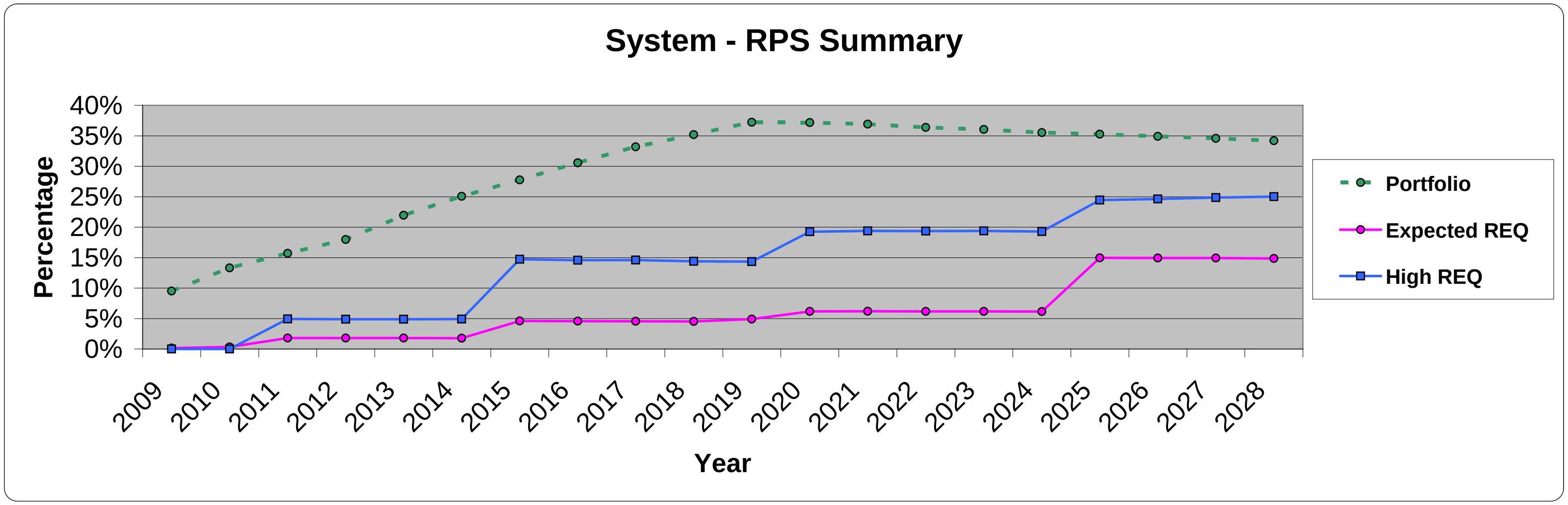


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 15%, Class 3 DSM = Excluded

System - RPS Report - Case # 43

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,355	13,793	18,875	25,080	32,232	40,207	49,070	58,733	69,091	80,147	91,322	102,511	113,650	124,804	135,952	141,864	147,753	153,606	159,448
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	811	907	1,223	1,589	1,674	1,754	2,052	2,316	2,309	2,188	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,079
Oregon	1,382	2,912	4,095	5,650	7,820	10,469	12,073	14,166	16,682	19,603	22,890	25,393	27,841	30,229	32,574	34,873	36,260	37,559	38,761	39,865
Cumulative Surplus Credit Bank Balance	**6,942**	**12,681**	**18,699**	**25,432**	**34,122**	**44,290**	**53,954**	**64,989**	**77,467**	**91,010**	**105,347**	**118,903**	**132,545**	**146,053**	**159,535**	**172,975**	**180,258**	**187,427**	**194,464**	**201,391**
Adjusted Qualifying Renewables																				
Utah	2,959	3,795	4,438	5,082	6,205	7,152	7,974	8,863	9,663	10,358	11,055	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,233
Other (ID,WY)	828	1,368	1,719	2,091	2,700	3,244	3,720	4,244	4,711	5,095	5,496	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,741
California	88	176	185	194	209	242	277	312	343	371	398	398	398	397	397	397	392	387	382	377
Washington	266	415	518	632	835	999	1,168	1,328	1,471	1,598	1,721	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,701
Oregon	989	1,530	1,883	2,264	2,889	3,382	3,832	4,337	4,783	5,198	5,588	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,264
Adjusted Qualifying Renewables	**5,130**	**7,283**	**8,743**	**10,263**	**12,839**	**15,019**	**16,971**	**19,084**	**20,971**	**22,620**	**24,257**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,315**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

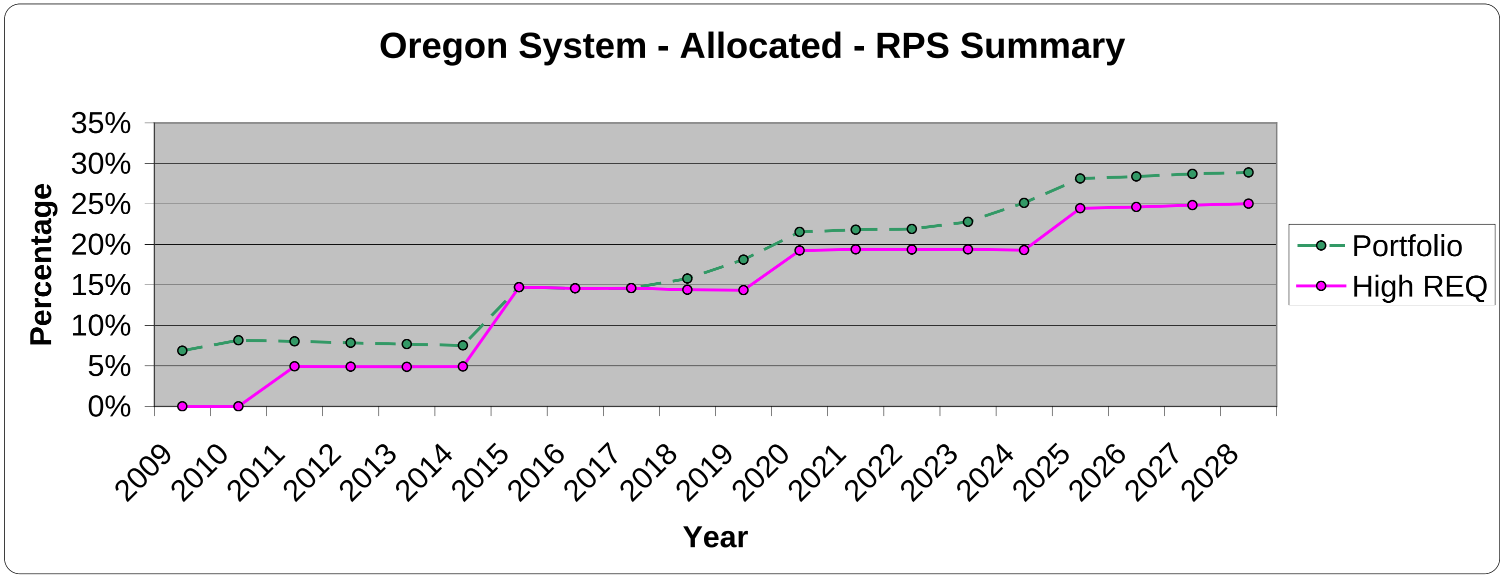


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 15%, Class 3 DSM = Excluded

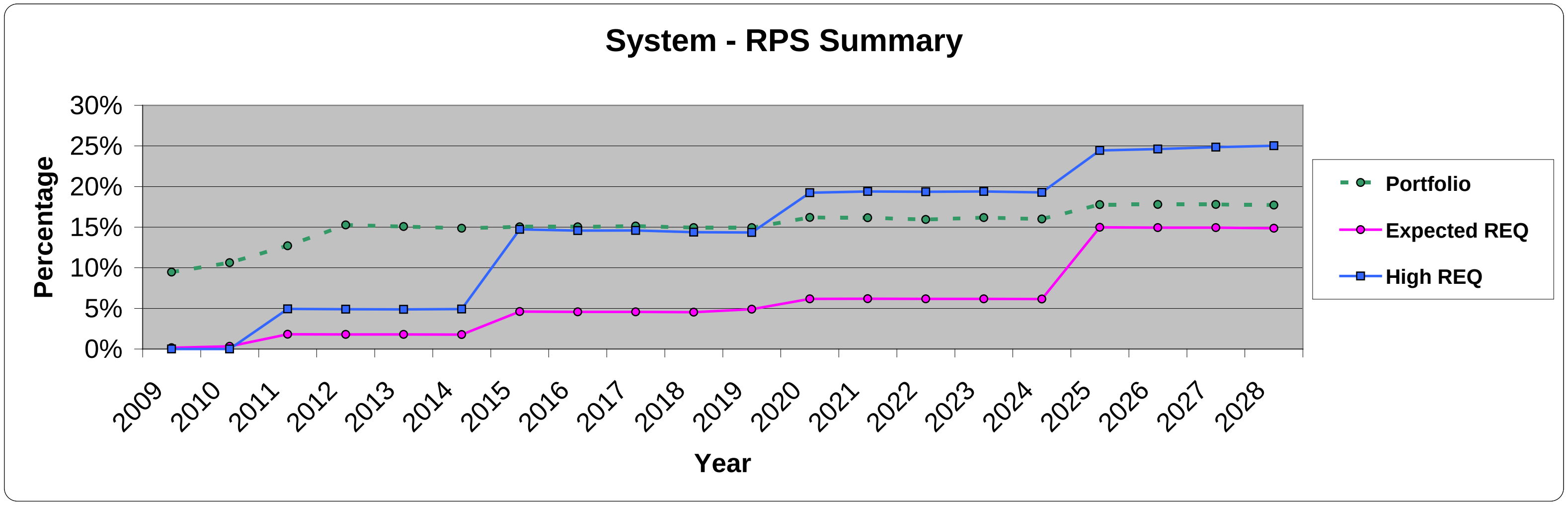
Oregon System - Allocated RPS Report - Case # 44

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Oregon - System																				
Energy GWh																				
RPS Requirement (System)	-	-	2,750	2,794	2,858	2,942	9,003	9,102	9,223	9,245	9,353	12,680	12,871	12,969	13,121	13,200	16,863	17,140	17,467	17,802
Eligible Resources	3,581	4,090	4,090	4,091	4,090	4,088	3,818	3,843	3,836	3,818	3,832	3,829	3,827	3,687	3,686	3,577	3,571	3,564	3,558	3,552
Incremental IRP Resources	127	365	372	391	403	423	818	2,000	4,097	6,327	7,977	10,362	10,658	10,988	11,729	13,624	15,838	16,196	16,615	16,988
Surplus/(Deficit)	3,708	4,456	1,712	1,688	1,636	1,568	(4,367)	(3,260)	(1,290)	900	2,457	1,510	1,613	1,707	2,294	4,001	2,545	2,620	2,707	2,739
Banking:																				
Surplus Credit Prior Year	1,484	5,191	9,647	11,359	13,047	14,683	16,251	11,883	8,624	7,333	8,233	10,690	12,200	13,813	15,520	17,814	21,815	24,360	26,980	29,687
Current Year Surplus Credits	3,708	4,456	1,712	1,688	1,636	1,568	-	-	-	900	2,457	1,510	1,613	1,707	2,294	4,001	2,545	2,620	2,707	2,739
Surplus Credits Used in Current Year	-	-	-	-	-	-	(4,367)	(3,260)	(1,290)	-	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	5,191	9,647	11,359	13,047	14,683	16,251	11,883	8,624	7,333	8,233	10,690	12,200	13,813	15,520	17,814	21,815	24,360	26,980	29,687	32,426
Adjusted Qualifying Renewables	3,708	4,456	4,462	4,481	4,493	4,511	9,003	9,102	9,223	10,145	11,809	14,191	14,484	14,675	15,415	17,201	19,408	19,760	20,174	20,540
Allocation Factor	26.5%	25.7%	25.5%	25.3%	25.2%	24.9%	24.8%	24.7%	24.6%	24.6%	24.6%	24.4%	24.3%	24.3%	24.3%	24.3%	24.1%	23.8%	23.6%	23.4%
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	7%	8%	8%	8%	8%	8%	15%	15%	15%	16%	18%	22%	22%	22%	23%	25%	28%	28%	29%	29%
Portfolio Meets RPS																				
High REQ	0%	0%	5%	5%	5%	5%	15%	15%	15%	14%	14%	19%	19%	19%	19%	19%	24%	25%	25%	25%



System - RPS Report - Case # 45

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,718	12,446	16,874	21,369	25,929	30,421	35,002	39,674	44,357	49,072	53,748	58,431	63,055	67,850	72,643	71,855	71,166	70,376	69,536
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	567	658	791	803	565	336	358	369	115	-	-	-	-	-	-	-	-	-
Oregon	1,376	2,521	3,272	4,432	5,573	6,682	6,228	5,801	5,389	4,972	4,538	3,296	2,010	670	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,539**	**16,284**	**21,964**	**27,732**	**33,414**	**37,214**	**41,138**	**45,421**	**49,697**	**53,725**	**57,044**	**60,441**	**63,725**	**67,850**	**72,643**	**71,855**	**71,166**	**70,376**	**69,536**
Adjusted Qualifying Renewables																				
Utah	2,950	3,168	3,728	4,428	4,495	4,560	4,492	4,581	4,672	4,683	4,715	4,750	4,763	4,717	4,866	4,868	5,257	5,301	5,358	5,391
Other (ID,WY)	823	1,024	1,325	1,726	1,739	1,767	1,722	1,778	1,827	1,824	1,835	1,851	1,855	1,825	1,908	1,873	1,938	1,994	2,006	2,026
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	388	512	522	526	532	546	559	561	632	636	640	644	647	651	655	659	662	666
Oregon	983	1,145	1,451	1,868	1,861	1,842	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,812**	**7,077**	**8,729**	**8,820**	**8,908**	**9,197**	**9,381**	**9,568**	**9,598**	**9,745**	**10,669**	**10,730**	**10,681**	**10,948**	**10,950**	**12,264**	**12,394**	**12,506**	**12,602**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	15%	15%	15%	15%	15%	15%	15%	15%	16%	16%	16%	16%	16%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

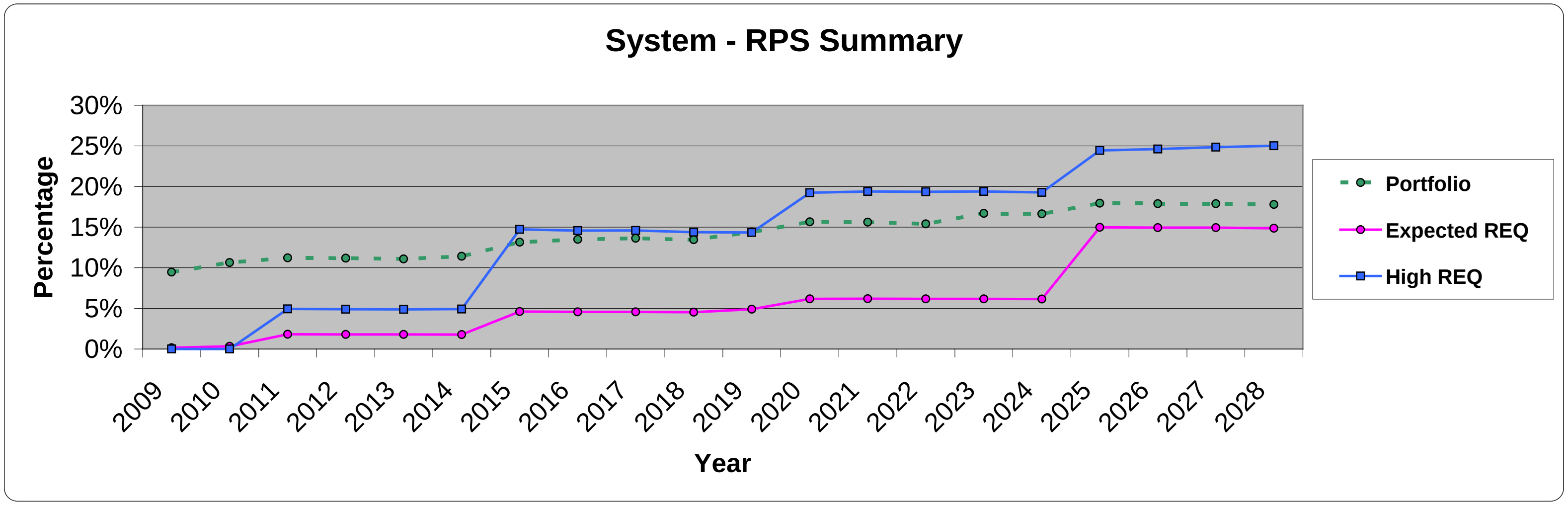


Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base/PTC expires, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 46

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,721	12,096	15,528	19,027	22,704	26,534	30,572	34,702	38,844	43,311	47,717	52,131	56,485	61,544	66,663	66,319	65,899	65,379	64,782
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	503	411	427	460	283	116	160	171	-	-	-	-	-	-	-	-	-	-
Oregon	1,377	2,523	3,059	3,617	4,159	4,743	3,898	3,152	2,422	1,687	1,122	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,928**	**11,545**	**15,658**	**19,556**	**23,613**	**27,907**	**30,715**	**33,839**	**37,284**	**40,702**	**44,433**	**47,717**	**52,131**	**56,485**	**61,544**	**66,663**	**66,319**	**65,899**	**65,379**	**64,782**
Adjusted Qualifying Renewables																				
Utah	2,951	3,170	3,375	3,432	3,499	3,677	3,830	4,038	4,130	4,142	4,492	4,522	4,535	4,488	5,090	5,143	5,257	5,301	5,358	5,391
Other (ID,WY)	823	1,025	1,129	1,169	1,179	1,263	1,343	1,465	1,514	1,512	1,706	1,718	1,722	1,692	2,039	2,034	2,048	2,061	2,075	2,087
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	324	330	340	364	411	447	461	463	632	636	640	644	647	651	655	659	662	666
Oregon	983	1,146	1,237	1,265	1,262	1,317	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,817**	**6,249**	**6,391**	**6,484**	**6,835**	**8,036**	**8,427**	**8,614**	**8,646**	**9,393**	**10,308**	**10,369**	**10,319**	**11,302**	**11,386**	**12,373**	**12,461**	**12,574**	**12,664**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	11%	11%	11%	13%	14%	14%	13%	14%	16%	16%	15%	17%	17%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

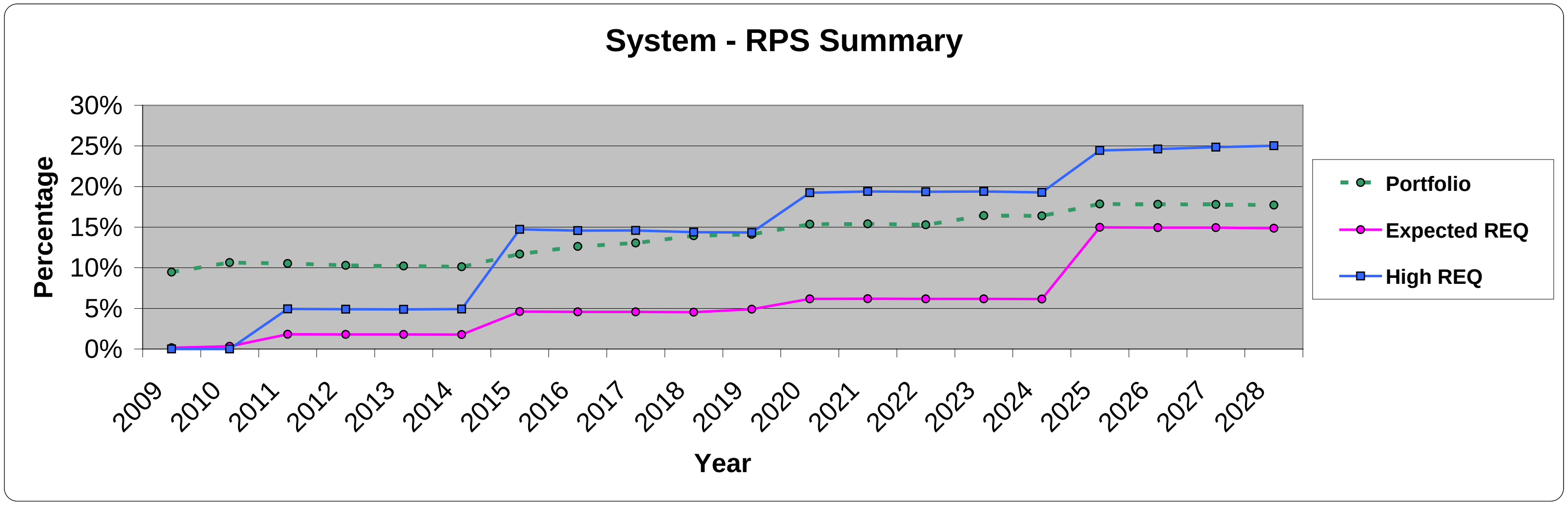


Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = Fixed RPS-compliant wind schedule, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 47

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,721	11,932	15,148	18,431	21,782	25,069	28,797	32,719	37,037	41,320	45,589	49,893	54,139	59,062	64,057	63,463	62,794	62,024	61,178
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	473	342	348	361	124	18	66	165	-	-	-	-	-	-	-	-	-	-
Oregon	1,377	2,523	2,959	3,387	3,799	4,189	3,023	2,094	1,243	611	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,928**	**11,545**	**15,364**	**18,877**	**22,578**	**26,332**	**28,216**	**30,910**	**34,027**	**37,813**	**41,320**	**45,589**	**49,893**	**54,139**	**59,062**	**64,057**	**63,463**	**62,794**	**62,024**	**61,178**
Adjusted Qualifying Renewables																				
Utah	2,951	3,170	3,210	3,216	3,283	3,351	3,287	3,729	3,922	4,318	4,344	4,406	4,449	4,439	4,975	5,039	5,257	5,301	5,358	5,391
Other (ID,WY)	823	1,025	1,038	1,049	1,058	1,077	1,031	1,287	1,393	1,613	1,621	1,651	1,671	1,663	1,972	1,973	1,986	1,999	2,012	2,024
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	294	291	301	305	370	391	422	495	632	636	640	644	647	651	655	659	662	666
Oregon	983	1,146	1,137	1,135	1,132	1,123	2,228	2,244	2,266	2,277	2,341	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,817**	**5,864**	**5,886**	**5,978**	**6,068**	**7,140**	**7,883**	**8,247**	**8,956**	**9,200**	**10,124**	**10,232**	**10,241**	**11,120**	**11,221**	**12,312**	**12,399**	**12,511**	**12,601**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	10%	10%	12%	13%	13%	14%	14%	15%	15%	15%	16%	16%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

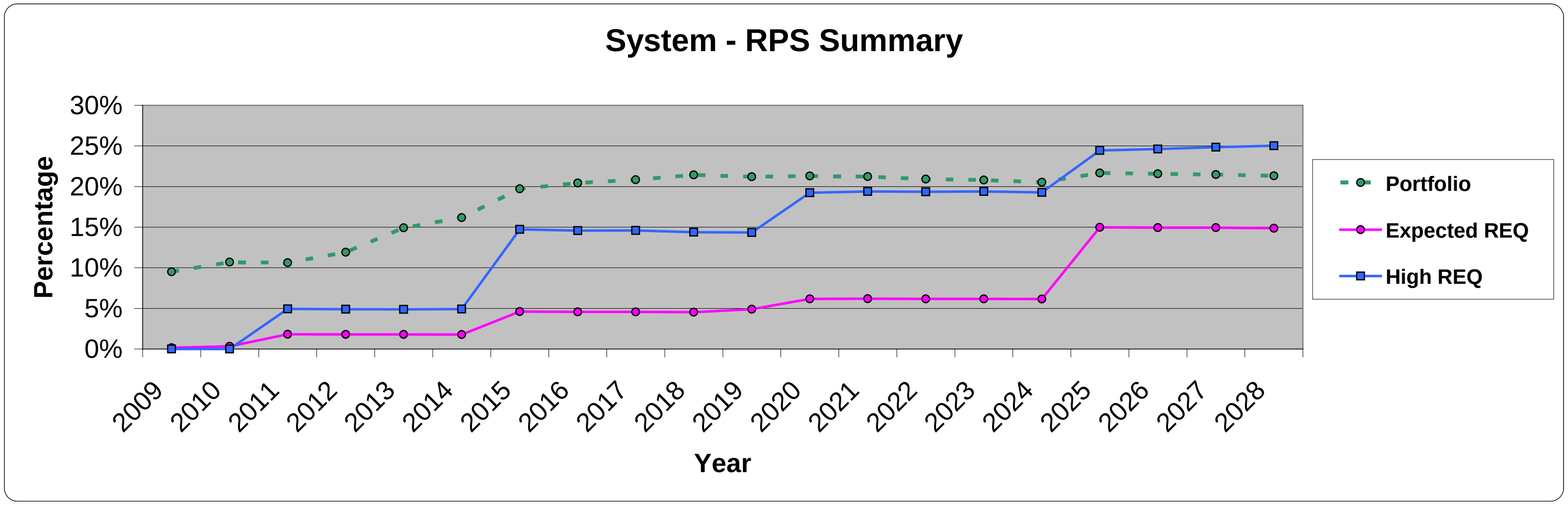


Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = Optimized RPS-compliant renewables, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 48

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,745	11,977	15,585	20,039	24,932	30,837	37,036	43,422	50,064	56,731	63,428	70,139	76,800	83,476	90,146	91,580	92,991	94,366	95,730
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	480	418	634	856	883	889	967	1,039	829	569	557	539	522	514	499	479	462	444
Oregon	1,382	2,537	2,987	3,651	4,767	6,075	6,455	6,981	7,574	8,309	9,021	8,914	8,760	8,549	8,300	8,000	6,812	5,563	4,241	2,847
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**15,443**	**19,654**	**25,440**	**31,863**	**38,175**	**44,906**	**51,962**	**59,413**	**66,581**	**72,910**	**79,456**	**85,887**	**92,298**	**98,660**	**98,891**	**99,033**	**99,069**	**99,021**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,232	3,609	4,454	4,893	5,904	6,200	6,385	6,642	6,667	6,697	6,712	6,661	6,676	6,671	6,691	6,712	6,733	6,755
Other (ID,WY)	828	1,033	1,050	1,268	1,716	1,956	2,533	2,710	2,817	2,953	2,962	2,984	2,992	2,960	2,968	2,925	2,949	2,972	2,995	3,017
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	363	515	586	790	842	872	919	919	917	916	907	906	905	900	894	889	883
Oregon	989	1,155	1,150	1,372	1,836	2,040	2,609	2,769	2,860	3,013	3,011	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**5,852**	**5,915**	**6,806**	**8,724**	**9,689**	**12,059**	**12,754**	**13,177**	**13,780**	**13,822**	**14,030**	**14,092**	**14,022**	**14,076**	**14,060**	**14,953**	**15,018**	**15,096**	**15,174**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	15%	16%	20%	20%	21%	21%	21%	21%	21%	21%	21%	21%	22%	22%	21%	21%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



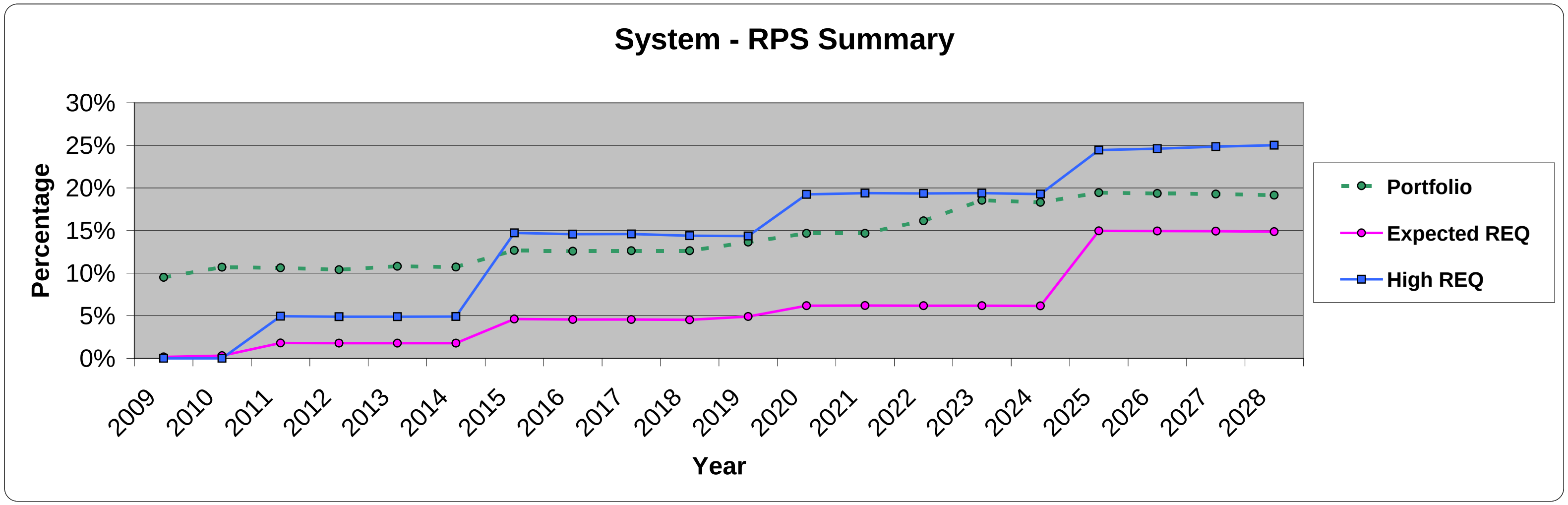
Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Included

B-Series Portfolio RPS Summary

System - RPS Report - Case # 2B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,743	11,975	15,216	18,646	22,145	25,809	29,515	33,284	37,125	40,937	44,506	48,067	52,798	58,613	64,419	64,987	65,531	66,044	66,542
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	350	380	415	220	25	34	50	-	-	-	-	102	199	183	163	146	128
Oregon	1,382	2,536	2,985	3,428	3,928	4,407	3,464	2,522	1,581	669	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,941**	**11,583**	**15,439**	**18,994**	**22,954**	**26,967**	**29,494**	**32,062**	**34,898**	**37,843**	**40,937**	**44,506**	**48,067**	**52,798**	**58,715**	**64,618**	**65,170**	**65,694**	**66,190**	**66,670**
Adjusted Qualifying Renewables																				
Utah	2,959	3,184	3,231	3,241	3,430	3,499	3,664	3,706	3,769	3,841	4,094	4,112	4,138	4,807	5,814	5,807	5,825	5,845	5,871	5,889
Other (ID,WY)	828	1,032	1,049	1,063	1,140	1,162	1,248	1,274	1,305	1,338	1,476	1,480	1,490	1,878	2,463	2,421	2,438	2,455	2,476	2,490
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	328	332	381	386	395	408	632	636	640	644	749	747	741	736	731	725
Oregon	988	1,155	1,149	1,150	1,220	1,211	2,228	2,244	2,266	2,277	2,430	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,129**	**5,850**	**5,912**	**5,945**	**6,322**	**6,417**	**7,744**	**7,843**	**7,978**	**8,117**	**8,895**	**9,660**	**9,740**	**10,823**	**12,553**	**12,534**	**13,417**	**13,476**	**13,558**	**13,625**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	11%	11%	13%	13%	13%	13%	14%	15%	15%	16%	19%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

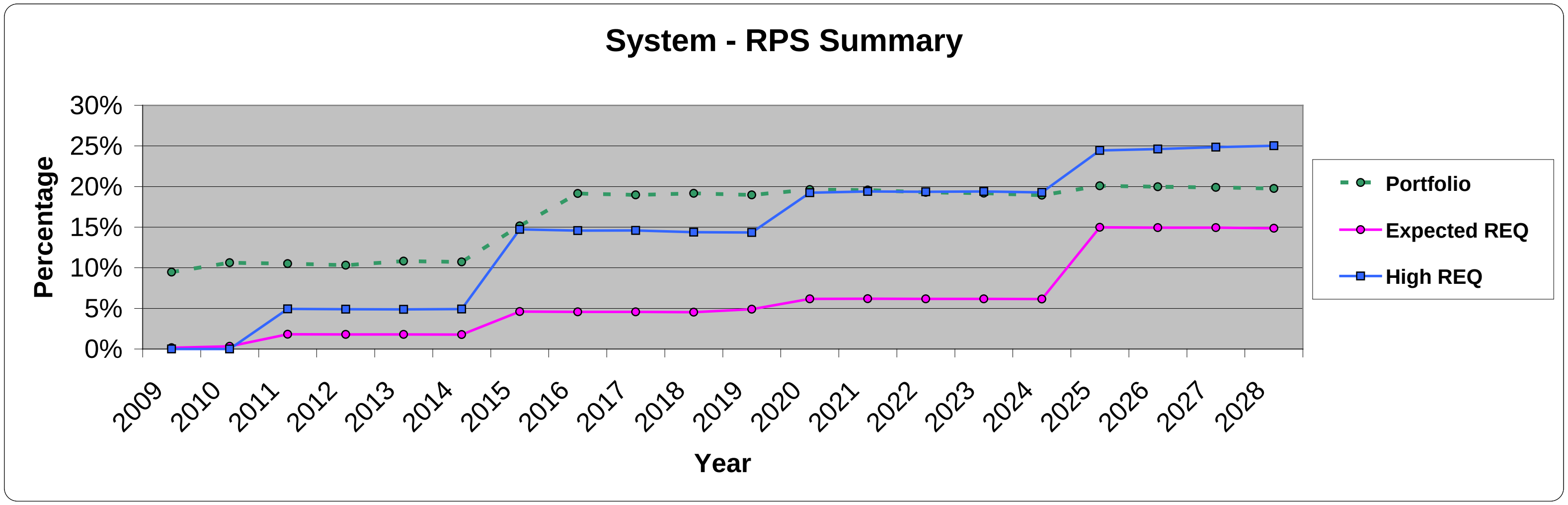


Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 5B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,076	26,608	32,463	38,342	44,362	50,407	56,483	62,574	68,614	74,668	80,718	81,531	82,321	83,075	83,818
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	379	576	811	833	602	342	330	312	295	287	272	253	235	217
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,935	4,257	4,553	4,923	5,269	4,800	4,286	3,714	3,107	2,445	901	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,861**	**22,832**	**26,856**	**30,922**	**37,295**	**43,706**	**50,118**	**56,279**	**61,626**	**67,190**	**72,639**	**78,070**	**83,451**	**82,704**	**82,574**	**83,310**	**84,035**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	4,533	5,855	5,879	6,021	6,045	6,076	6,091	6,040	6,055	6,050	6,070	6,091	6,112	6,134
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,746	2,511	2,524	2,595	2,603	2,623	2,629	2,598	2,604	2,563	2,583	2,602	2,621	2,639
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	539	779	780	806	806	803	803	793	793	792	786	781	775	770
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,566	2,563	2,647	2,646	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,892**	**6,330**	**6,427**	**9,269**	**11,944**	**11,988**	**12,321**	**12,363**	**12,934**	**12,995**	**12,926**	**12,978**	**12,963**	**13,852**	**13,914**	**13,988**	**14,062**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	15%	19%	19%	19%	19%	20%	20%	19%	19%	19%	20%	20%	20%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

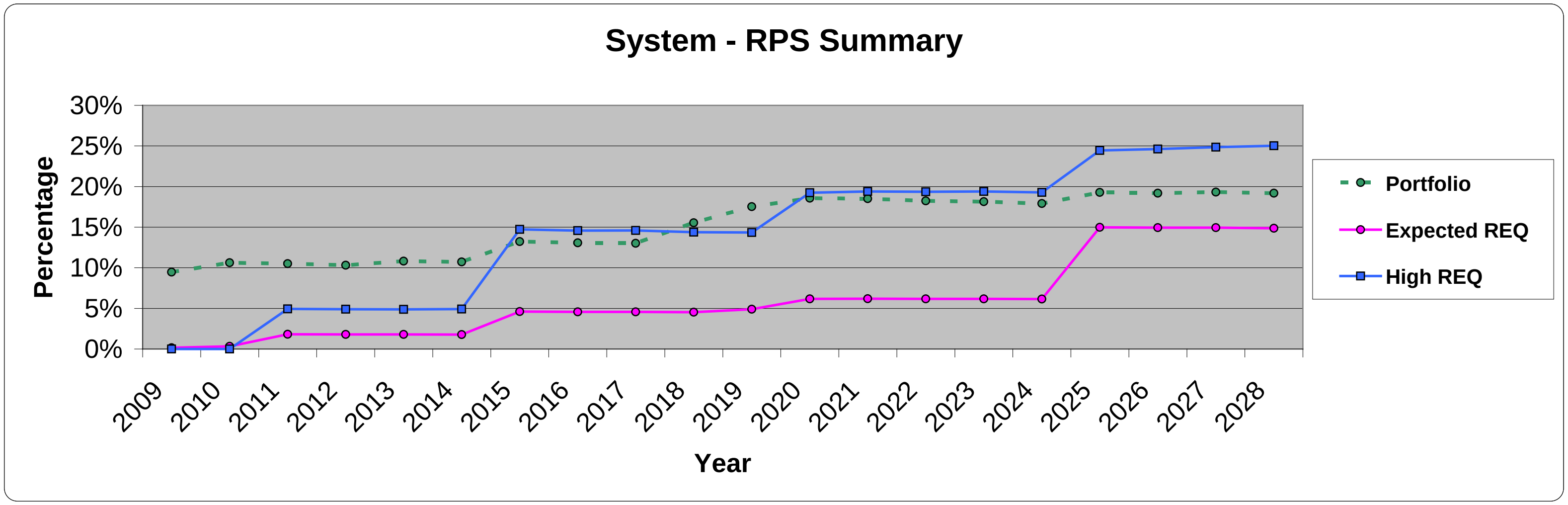


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 5B_CCCT

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,076	25,936	29,823	33,735	38,638	44,285	49,962	55,654	61,294	66,950	72,600	73,098	73,573	74,096	74,607
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	93	270	326	196	184	166	149	141	142	137	135	132
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,538	2,702	1,844	1,557	1,670	968	222	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,861**	**22,832**	**26,856**	**29,730**	**32,619**	**35,672**	**40,466**	**46,281**	**51,126**	**56,060**	**61,460**	**67,099**	**72,741**	**73,239**	**73,710**	**74,230**	**74,739**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	3,861	3,887	3,912	4,903	5,647	5,677	5,692	5,640	5,656	5,651	5,755	5,776	5,881	5,902
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,360	1,378	1,387	1,951	2,373	2,390	2,396	2,365	2,370	2,330	2,397	2,414	2,481	2,498
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	417	420	421	602	733	731	730	720	720	719	729	723	733	728
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,244	2,266	2,277	2,412	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,892**	**6,330**	**6,427**	**8,089**	**8,162**	**8,229**	**9,986**	**11,428**	**12,230**	**12,290**	**12,220**	**12,273**	**12,258**	**13,293**	**13,353**	**13,575**	**13,648**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	13%	16%	18%	19%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

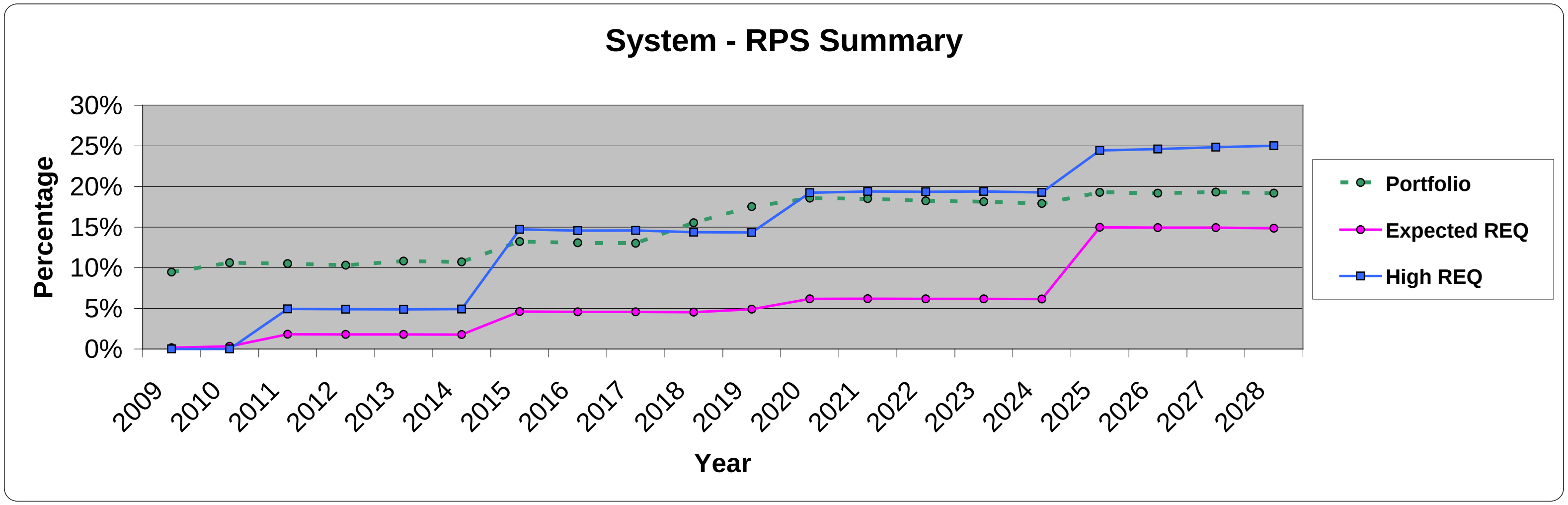


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II, Fixed CCCT)

System - RPS Report - Case # 5B_CCCT-WC

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,076	25,936	29,823	33,735	38,638	44,285	49,962	55,653	61,294	66,949	72,600	73,097	73,573	74,095	74,607
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	93	270	326	196	184	166	149	141	142	137	135	132
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,538	2,702	1,844	1,557	1,670	968	221	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,861**	**22,832**	**26,856**	**29,730**	**32,619**	**35,672**	**40,465**	**46,280**	**51,126**	**56,059**	**61,460**	**67,099**	**72,741**	**73,239**	**73,710**	**74,230**	**74,739**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	3,860	3,887	3,912	4,903	5,647	5,677	5,692	5,640	5,656	5,651	5,755	5,776	5,881	5,902
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,360	1,378	1,387	1,951	2,373	2,390	2,396	2,365	2,370	2,330	2,397	2,414	2,481	2,498
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	417	420	421	602	733	731	730	720	720	719	729	723	733	728
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,244	2,266	2,277	2,412	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,892**	**6,330**	**6,427**	**8,089**	**8,162**	**8,229**	**9,986**	**11,428**	**12,230**	**12,290**	**12,220**	**12,273**	**12,258**	**13,293**	**13,353**	**13,575**	**13,648**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	13%	16%	18%	19%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

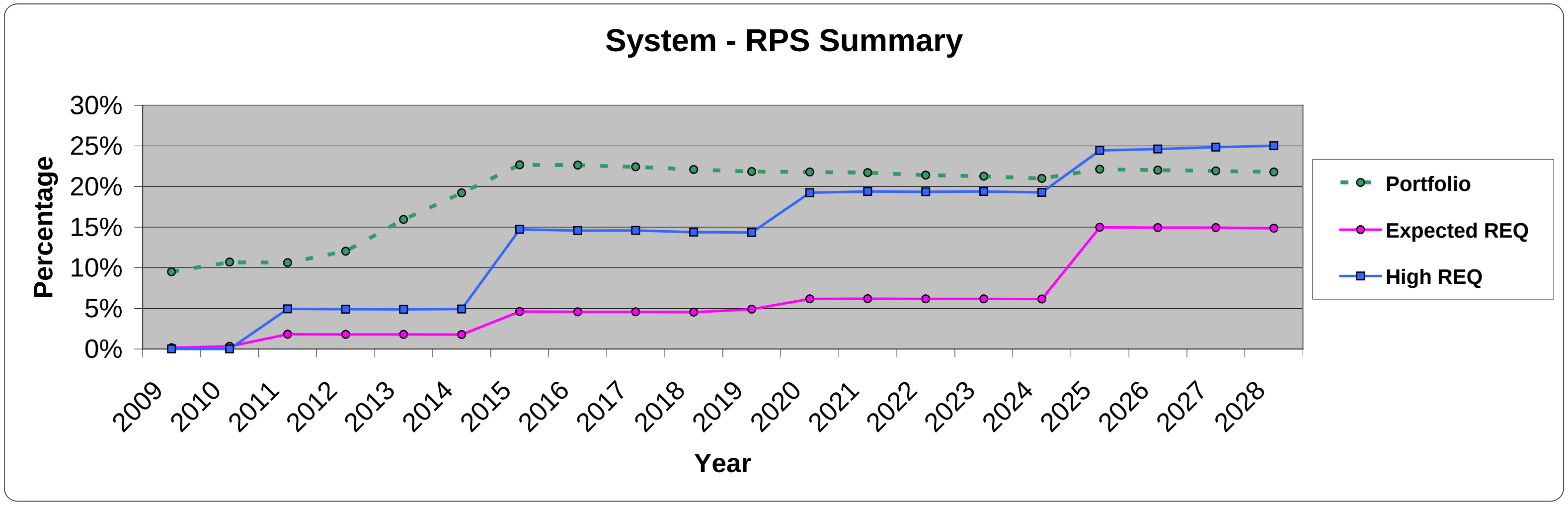


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II, Fixed CCCT-WC)

System - RPS Report - Case # 8B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,742	11,973	15,613	20,324	25,996	32,671	39,457	46,267	53,089	59,935	66,812	73,703	80,543	87,399	94,249	95,862	97,453	99,008	100,551
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	423	686	1,046	1,166	1,137	1,151	1,150	895	634	623	604	588	579	565	545	527	509
Oregon	1,382	2,536	2,984	3,668	4,939	6,709	7,545	8,415	9,258	10,099	10,916	10,913	10,864	10,757	10,613	10,416	9,332	8,185	6,964	5,670
Cumulative Surplus Credit Bank Balance	**6,942**	**11,581**	**15,436**	**19,703**	**25,949**	**33,750**	**41,383**	**49,009**	**56,676**	**64,338**	**71,746**	**78,359**	**85,190**	**91,904**	**98,599**	**105,244**	**105,758**	**106,183**	**106,499**	**106,731**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,640	4,712	5,672	6,675	6,786	6,810	6,822	6,846	6,877	6,891	6,840	6,855	6,850	6,871	6,892	6,913	6,934
Other (ID,WY)	828	1,031	1,049	1,285	1,861	2,400	2,975	3,048	3,062	3,057	3,065	3,089	3,096	3,065	3,073	3,030	3,055	3,079	3,103	3,126
California	88	176	185	194	204	213	225	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	368	562	729	931	949	950	952	952	950	949	939	939	938	932	927	921	916
Oregon	989	1,154	1,149	1,391	1,991	2,502	3,065	3,114	3,109	3,119	3,117	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**6,879**	**9,329**	**11,516**	**13,870**	**14,130**	**14,174**	**14,202**	**14,243**	**14,346**	**14,409**	**14,340**	**14,394**	**14,377**	**15,271**	**15,338**	**15,417**	**15,496**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	16%	19%	23%	23%	22%	22%	22%	22%	22%	21%	21%	21%	22%	22%	22%	22%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

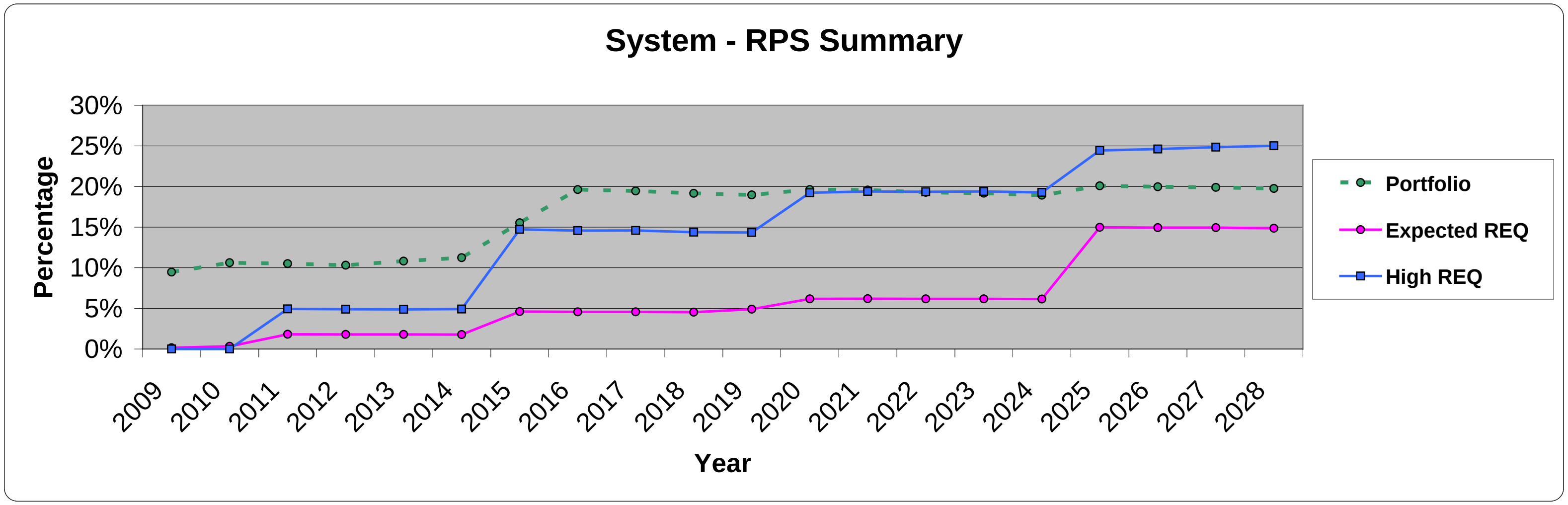


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 9B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,139	18,573	22,206	26,869	32,854	38,863	44,884	50,930	57,006	63,097	69,136	75,191	81,241	82,053	82,844	83,598	84,341
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	440	427	623	859	857	603	342	330	312	295	287	272	253	235	217
Oregon	1,376	2,519	2,952	3,381	3,883	4,442	4,089	4,488	4,860	5,231	5,578	5,109	4,594	4,022	3,415	2,754	1,209	-	-	-
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**18,861**	**22,832**	**27,088**	**31,385**	**37,965**	**44,582**	**50,972**	**57,110**	**62,456**	**68,021**	**73,470**	**78,901**	**84,281**	**83,534**	**83,096**	**83,833**	**84,557**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,219	3,433	3,633	4,663	5,985	6,009	6,021	6,046	6,076	6,091	6,040	6,055	6,050	6,070	6,091	6,112	6,134
Other (ID,WY)	822	1,022	1,034	1,050	1,143	1,238	1,821	2,586	2,599	2,595	2,603	2,623	2,629	2,598	2,604	2,563	2,583	2,602	2,621	2,639
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	356	563	803	804	806	806	803	803	793	793	792	786	781	775	770
Oregon	982	1,144	1,133	1,137	1,222	1,291	2,228	2,643	2,639	2,648	2,647	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**5,893**	**6,331**	**6,732**	**9,498**	**12,249**	**12,294**	**12,323**	**12,365**	**12,934**	**12,995**	**12,926**	**12,978**	**12,963**	**13,852**	**13,914**	**13,988**	**14,062**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	16%	20%	19%	19%	19%	20%	20%	19%	19%	19%	20%	20%	20%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

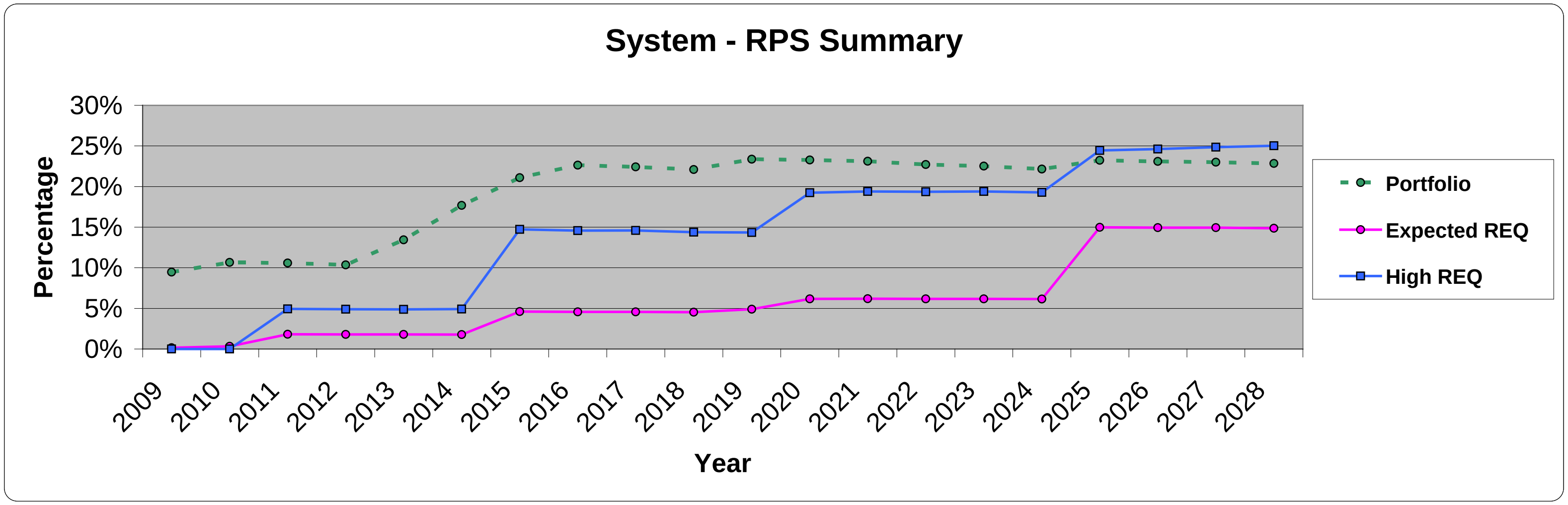


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 10B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,724	11,947	15,177	19,264	24,544	30,806	37,592	44,402	51,224	58,492	65,790	73,103	80,365	87,642	94,914	96,948	98,961	100,937	102,902
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	476	347	498	860	1,019	1,062	1,151	1,150	972	788	777	758	742	733	719	699	681	663
Oregon	1,377	2,525	2,968	3,404	4,299	5,836	6,428	7,299	8,141	8,982	10,047	10,290	10,485	10,623	10,723	10,772	9,930	9,023	8,040	6,981
Cumulative Surplus Credit Bank Balance	**6,929**	**11,550**	**15,390**	**18,927**	**24,060**	**31,240**	**38,253**	**45,952**	**53,694**	**61,355**	**69,510**	**76,868**	**84,365**	**91,746**	**99,106**	**106,419**	**107,597**	**108,683**	**109,658**	**110,547**
Adjusted Qualifying Renewables																				
Utah	2,951	3,173	3,222	3,230	4,087	5,280	6,262	6,786	6,810	6,822	7,268	7,298	7,313	7,262	7,277	7,272	7,292	7,313	7,334	7,356
Other (ID,WY)	823	1,026	1,044	1,056	1,510	2,177	2,738	3,048	3,062	3,057	3,309	3,334	3,343	3,312	3,320	3,276	3,304	3,331	3,357	3,383
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	296	294	448	657	855	949	950	952	1,029	1,027	1,026	1,016	1,016	1,015	1,009	1,004	998	993
Oregon	983	1,148	1,144	1,144	1,615	2,269	2,820	3,114	3,109	3,119	3,364	3,339	3,329	3,291	3,282	3,260	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,824**	**5,891**	**5,918**	**7,864**	**10,597**	**12,898**	**14,130**	**14,174**	**14,202**	**15,233**	**15,334**	**15,349**	**15,222**	**15,239**	**15,171**	**16,018**	**16,088**	**16,169**	**16,251**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	13%	18%	21%	23%	22%	22%	23%	23%	23%	23%	23%	22%	23%	23%	23%	23%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

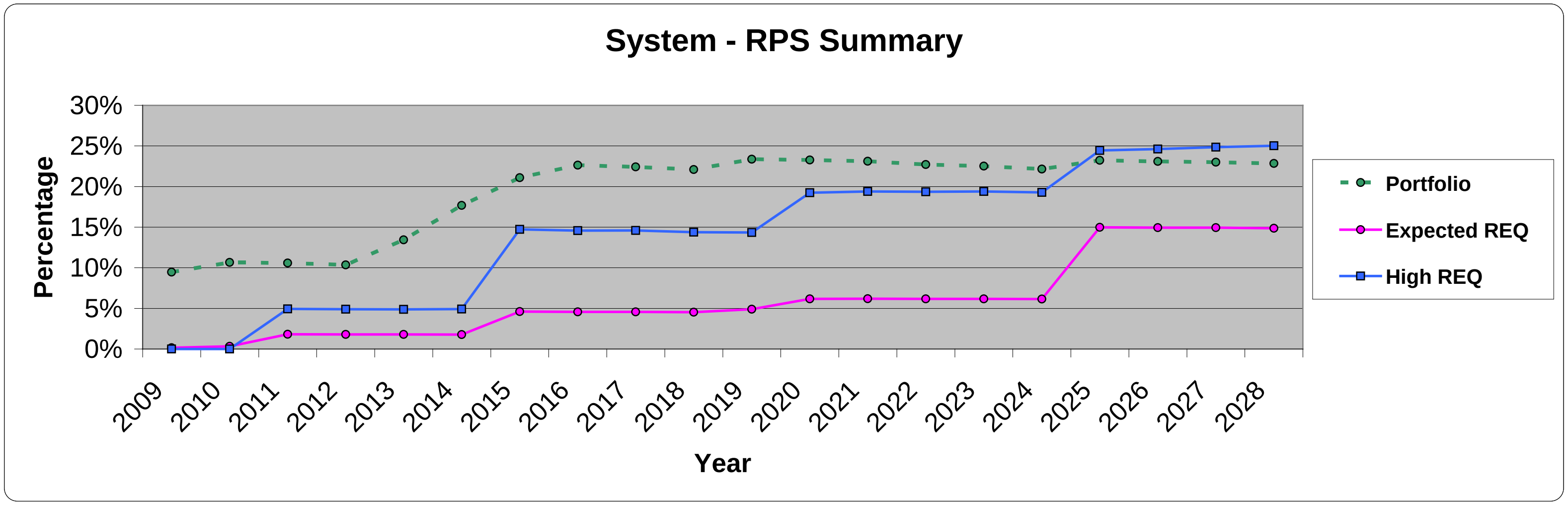

System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 17b

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,724	11,947	15,177	19,264	24,544	30,806	37,592	44,402	51,224	58,492	65,790	73,103	80,365	87,642	94,914	96,948	98,961	100,937	102,902
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	476	347	498	860	1,019	1,062	1,151	1,150	972	788	777	758	742	733	719	699	681	663
Oregon	1,377	2,525	2,968	3,404	4,299	5,836	6,428	7,299	8,141	8,982	10,047	10,290	10,485	10,623	10,723	10,772	9,930	9,023	8,040	6,981
Cumulative Surplus Credit Bank Balance	**6,929**	**11,550**	**15,390**	**18,927**	**24,060**	**31,240**	**38,253**	**45,952**	**53,694**	**61,355**	**69,510**	**76,868**	**84,365**	**91,746**	**99,106**	**106,419**	**107,597**	**108,683**	**109,658**	**110,547**
Adjusted Qualifying Renewables																				
Utah	2,951	3,173	3,222	3,230	4,087	5,280	6,262	6,786	6,810	6,822	7,268	7,298	7,313	7,262	7,277	7,272	7,292	7,313	7,334	7,356
Other (ID,WY)	823	1,026	1,044	1,056	1,510	2,177	2,738	3,048	3,062	3,057	3,309	3,334	3,343	3,312	3,320	3,276	3,304	3,331	3,357	3,383
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	296	294	448	657	855	949	950	952	1,029	1,027	1,026	1,016	1,016	1,015	1,009	1,004	998	993
Oregon	983	1,148	1,144	1,144	1,615	2,269	2,820	3,114	3,109	3,119	3,364	3,339	3,329	3,291	3,282	3,260	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,824**	**5,891**	**5,918**	**7,864**	**10,597**	**12,898**	**14,130**	**14,174**	**14,202**	**15,233**	**15,334**	**15,349**	**15,222**	**15,239**	**15,171**	**16,018**	**16,088**	**16,169**	**16,251**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	13%	18%	21%	23%	22%	22%	23%	23%	23%	23%	23%	22%	23%	23%	23%	23%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

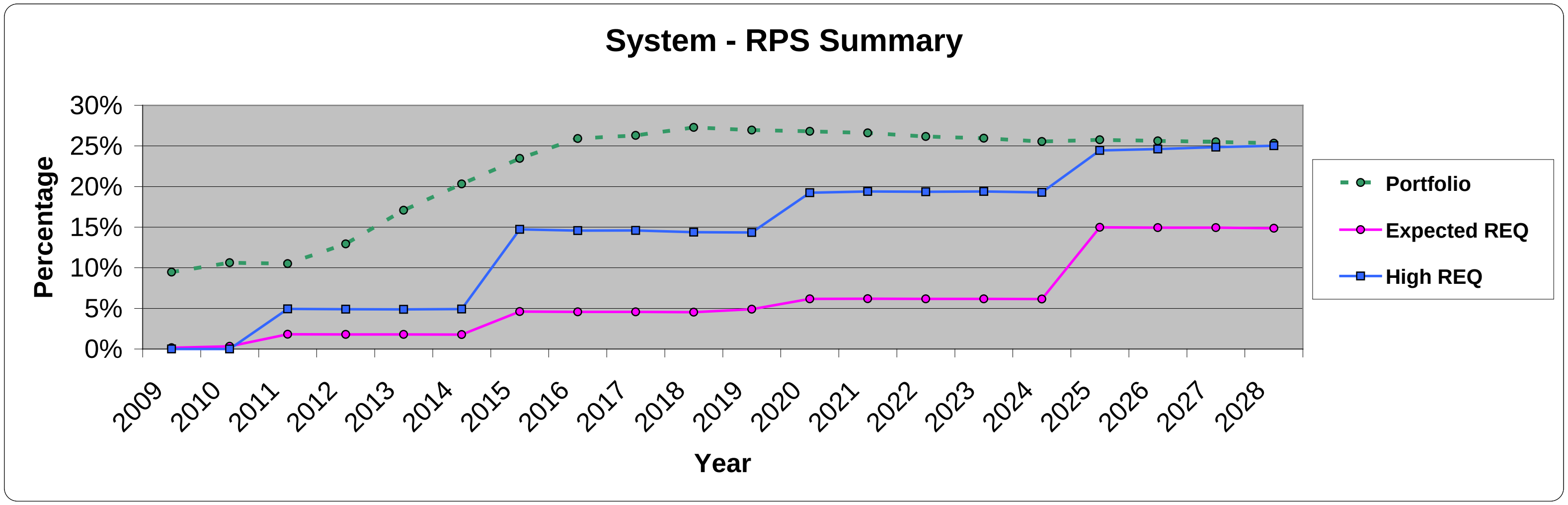


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 18B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,778	20,772	26,725	33,602	41,247	49,090	57,320	65,575	73,859	82,159	90,407	98,670	106,929	109,950	112,949	115,912	118,863
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	458	778	1,149	1,255	1,331	1,497	1,595	1,409	1,149	1,137	1,118	1,102	1,094	1,079	1,059	1,041	1,024
Oregon	1,376	2,519	2,952	3,767	5,208	7,145	8,101	9,476	10,925	12,594	14,237	15,056	15,824	16,535	17,206	17,827	17,552	17,206	16,780	16,271
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**20,003**	**26,758**	**35,019**	**42,958**	**52,053**	**61,512**	**71,510**	**81,221**	**90,063**	**99,120**	**108,060**	**116,978**	**125,849**	**128,581**	**131,215**	**133,733**	**136,158**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,858	4,994	5,953	6,877	7,644	7,844	8,230	8,254	8,285	8,299	8,248	8,263	8,258	8,279	8,300	8,321	8,342
Other (ID,WY)	822	1,022	1,034	1,407	2,020	2,560	3,090	3,542	3,659	3,868	3,878	3,908	3,918	3,888	3,897	3,852	3,886	3,919	3,951	3,983
California	88	176	185	194	204	213	233	263	270	286	286	336	339	341	345	348	352	354	357	360
Washington	264	300	293	408	613	780	968	1,106	1,139	1,209	1,209	1,207	1,206	1,197	1,196	1,195	1,190	1,184	1,179	1,173
Oregon	982	1,144	1,133	1,523	2,161	2,669	3,184	3,619	3,715	3,947	3,943	3,914	3,902	3,864	3,853	3,832	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**7,391**	**9,992**	**12,177**	**14,352**	**16,174**	**16,627**	**17,540**	**17,571**	**17,649**	**17,665**	**17,538**	**17,555**	**17,486**	**17,767**	**17,843**	**17,930**	**18,018**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	20%	23%	26%	26%	27%	27%	27%	27%	26%	26%	26%	26%	26%	26%	25%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

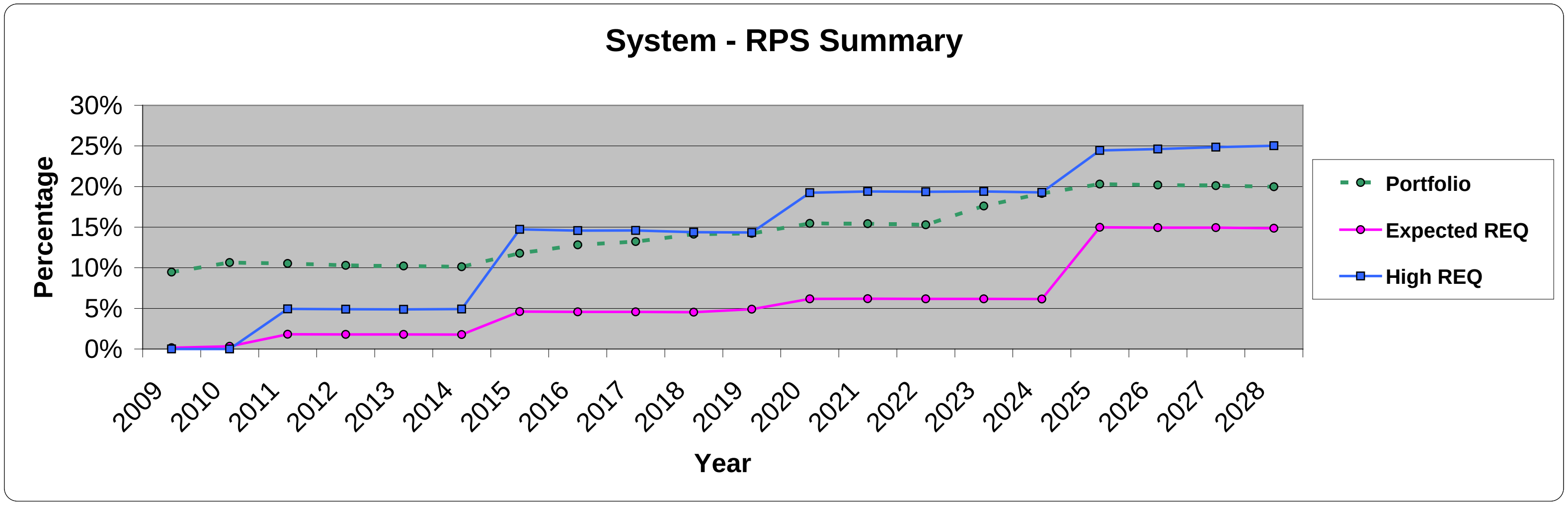


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 47B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,724	11,936	15,153	18,436	21,787	25,117	28,911	32,895	37,282	41,698	46,016	50,325	54,576	60,027	66,160	67,057	67,930	68,768	69,593
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	474	342	348	361	132	30	89	189	7	-	-	-	36	192	303	283	265	247
Oregon	1,377	2,524	2,961	3,389	3,801	4,192	3,052	2,161	1,346	755	146	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,929**	**11,549**	**15,370**	**18,884**	**22,586**	**26,341**	**28,300**	**31,102**	**34,330**	**38,226**	**41,851**	**46,016**	**50,325**	**54,576**	**60,062**	**66,353**	**67,360**	**68,213**	**69,033**	**69,840**
Adjusted Qualifying Renewables																				
Utah	2,952	3,172	3,212	3,217	3,283	3,351	3,329	3,794	3,984	4,387	4,417	4,447	4,451	4,441	5,451	6,134	6,154	6,173	6,196	6,216
Other (ID,WY)	824	1,026	1,038	1,049	1,058	1,077	1,056	1,325	1,430	1,653	1,663	1,675	1,673	1,664	2,250	2,612	2,632	2,651	2,671	2,689
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	294	291	301	305	370	403	434	507	632	636	640	644	682	807	802	796	791	785
Oregon	984	1,147	1,137	1,136	1,132	1,123	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,112**	**5,821**	**5,866**	**5,888**	**5,978**	**6,070**	**7,207**	**7,998**	**8,357**	**9,077**	**9,274**	**10,190**	**10,236**	**10,245**	**11,911**	**13,111**	**14,001**	**14,060**	**14,138**	**14,210**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	10%	10%	12%	13%	13%	14%	14%	15%	15%	15%	18%	19%	20%	20%	20%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = Optimized RPS-compliant renewables, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

Portfolio Summary Tables

Notes for the Portfolio Resource Tables

- Nameplate Capacity, MW
  - Nameplate capacities are reported for wind resources
  - Gas resource capacities reflect average annual capability rather than the generator nameplate. For combined-cycle resources, the values shown approximate the July maximum capabilities
  - Class 2 DSM resources (energy efficiency) capacities reflect summer peak values
  - Capacities shown for the coal plant CCS (carbon capture and sequestration) retrofits represent replacement capacity for an existing unit; the replacement capacity is smaller than the original unit size, which is due to a capacity penalty for capturing the CO_2
  - Capacities for all other resources represent maximum summer capabilities
- Swift 1 Upgrades **–** The three Swift upgrade projects (25 MW each) are shown under the year for which they enter commercial service (2012, 2013, and 2014); however, the planned in-service dates occur after the system peaks for these years. They are available to support the summer peak load in 2013, 2014, and 2015, respectively.
- High Plains and Duke PPA Wind Projects – The High Plains wind project has an October December 2009 in-service date, and is therefore shown under the year for which it enters commercial service (2009); the Duke project has a December 2009 in-service date, but is modeled with a start date of January 1, 2010, and is therefore shown in the year it is available to support the summer peak load (2010).
- Front Office Transactions – For the 10- and 20-year total columns, the megawatts represent the annual average values, as these resources are not accumulative over the planning period.
- Growth Stations **–** For the 20 Year column “Growth Resources” reflect an 8-year average for 2021-2028, the period that these resources are available for selection by the System Optimizer model.
- The resources shown with a zero are less than 0.5 megawatts
- Short-term resource totals at the bottom of the tables comprise the sum of front office transactions and growth resources

Table A.18 – Planned Resources

		Capacity, MW										**Resource Total**
	Planned Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
East												
	East PPA	-	-	-	201	-	-	-	-	-	-	**201**
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	**128**
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	**99**
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	**99**
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	**205**
West												
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	**42**
	Swift Hydro Upgrades	-	-	-	25	25	25	-	-	-	-	**75**
	Wind PPA	45	20	-	-	-	-	-	-	-	-	**65**
	Total Planned Resources	**172**	**222**	**82**	**292**	**49**	**49**	**10**	**18**	**10**	**10**	**913**

Note: The 2012 RFP Lake Side resource was removed as a planned resource in February 2009.

Case 01

PVRR: $20,045

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Total Wind	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	198	198
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	0
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	4.2	-	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	11.4	18.5	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1 & 3 Total	25	50.0	40	30	14	10	62	36	10	10	-	-	-	-	-	-	-	-	-	-	287	287
	DSM, Class 2, GO	-	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	11	27
	DSM, Class 2, UT	6	37.5	34	36	39	39	43	40	40	46	45	46	40	42	42	43	43	51	51	48	361	810
	DSM, Class 2, WY	-	-	-	-	8	8	8	8	8	8	8	8	8	8	9	9	9	9	9	9	47	133
	DSM, Class 2 Total	6	37.5	34	38	48	48	52	50	49	55	55	55	50	52	52	53	53	61	62	58	418	970
	FOT Utah Q3	-	-	-	-	50	50	50	50	-	50	50	50	-	-	50	50	50	50	50	-	25	30
	FOT Mead Q3	-	-	-	-	-	-	-	-	580	600	600	600	600	600	600	600	600	600	600	600	118	359
	FOT Mona/Nevada Utah Border	-	-	-	-	44	166	200	200	-	82	129	200	-	-	-	-	-	-	-	-	69	51
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	168	222	218	173	220	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	166	138	322	375	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62	307	-	-	-	N/A	46
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	2	-	-	-	-	-	-	-	-	-	24	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	20	5	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 2, WA	-	2	3	3	3	3	3	3	3	2	3	2	2	2	2	2	2	2	2	2	23	47
	DSM, Class 2, WM	-	-	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	231	430
	DSM, Class 2, YA	3	5	4	4	4	4	4	4	5	5	5	5	5	5	5	4	5	5	5	5	43	89
	DSM, Class 2 Total	3	6.2	37	37	37	37	37	37	38	27	27	27	27	27	27	26	27	27	27	27	298	567
	FOT COB Flat	-	-	301	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	248	293
	FOT MidColumbia Q3	-	-	-	362	400	400	400	400	170	400	400	400	400	400	400	400	400	400	400	400	253	327
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	122	128	135	138	129	130	132	219	N/A	142
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	284	283	109	-	-	230	200	893	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	119	217	120	97	196	287	329	N/A	171
	Annual Additions, Long Term Resources	195	279	167	988	151	148	186	411	106	100	88	82	76	79	80	79	81	88	89	85		
	Annual Additions, Short Term Resources	-	-	301	801	933	1,055	989	939	1,039	1,422	1,566	1,638	1,794	1,918	2,066	2,146	2,327	2,489	2,651	2,828		
	Total Annual Additions	195	279	468	1,789	1,085	1,203	1,175	1,350	1,145	1,522	1,654	1,720	1,871	1,997	2,146	2,225	2,407	2,577	2,739	2,914		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 02

PVRR: $21,512

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	628	-	-	641
	Total Wind	99	99	-	-	-	-	-	-	-	140	160	-	-	-	14	-	-	-	628	-	338	1,139
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	-	2	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	41	46.1	42	42	43	44	43	41	46	48	47	48	49	51	52	52	50	53	57	55	436	950
	DSM, Class 2, WY	1	3.1	6	8	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	67	164
	DSM, Class 2 Total	43	50.8	49	52	53	54	53	51	57	58	58	59	60	62	64	64	63	66	69	67	520	1,151
	FOT Utah Q3	-	-	-	-	-	-	9	44	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	411	421	427	480	480	590	480	480	600	600	600	89	302
	FOT Mona/Nevada Utah Border	-	-	-	120	200	200	200	200	87	-	-	-	82	98	200	128	200	200	200	200	101	116
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	-	5
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	35	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	370	663
	FOT COB Flat	-	-	219	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	239	288
	FOT Mid Columbia Flat	-	-	-	-	-	299	400	-	170	213	250	-	-	-	-	-	-	-	172	173	108	84
	FOT MidColumbia Q3	-	-	-	155	178	-	-	400	-	-	-	259	-	-	-	-	-	-	-	-	73	50
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	-	-	50	50	50	50	50	50	50	50	50	30	38
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	141	142	115	149	117	163	198	168	N/A	149
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	89	-	262	344	372	298	635	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	127	132	172	124	172	133	140	-	N/A	125
	Annual Additions, Long Term Resources	258	317	178	998	185	149	110	377	114	847	249	91	93	94	109	96	95	98	729	98		
	Annual Additions, Short Term Resources	-	-	219	714	817	938	949	933	1,027	863	1,008	1,074	1,217	1,329	1,464	1,530	1,700	1,856	1,995	2,164		
	Total Annual Additions	258	317	397	1,712	1,002	1,088	1,059	1,310	1,140	1,710	1,257	1,164	1,310	1,423	1,574	1,626	1,795	1,954	2,724	2,262		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 3

PVRR: $19,503

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	WY Pulverized Coal	-	-	-	-	-	-	-	-	-	790	-	-	-	-	-	-	-	-	-	-	790	790
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	138	162	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	237	63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	97	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	588	212	-	-	-	-	-	-	-	-	-	588	800
	Wind, WYSW, 35	-	303	60	129	-	135	451	223	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	499	400	192	-	135	750	223	138	750	712	-	-	-	-	-	-	-	-	-	3,186	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	47	55	49	49	49	51	51	50	53	51	55	55	56	58	59	73	64	55	57	55	505	1,092
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	72	172
	DSM, Class 2 Total	50	61	57	59	60	62	62	61	64	63	67	67	68	70	71	85	77	68	69	67	599	1,308
	FOT Mona Q3	-	-	-	68	124	200	200	200	48	-	-	-	-	-	64	124	-	17	200	200	84	72
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	166	167	480	154	271	480	480	390	480	600	600	65	237
	FOT Utah Q3	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	Total Wind	45	120	100	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	368
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	20	291	496
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	60	125
	DSM, Class 2 Total	37	38	40	40	39	40	40	40	40	30	30	30	30	30	30	31	30	30	30	30	383	684
	FOT COB Flat	-	-	-	-	-	-	-	-	-	-	338	-	338	338	338	-	-	-	-	338	-	84
	FOT COB Q3	-	-	129	389	400	389	289	239	239	239	-	77	-	-	-	338	338	338	338	-	232	187
	FOT Mid Columbia Flat	-	-	-	144	125	138	170	400	157	199	235	-	-	-	-	-	-	-	316	246	133	106
	FOT MidColumbia Q3	-	-	-	-	-	-	-	-	-	-	-	244	-	-	-	-	-	-	-	-	-	12
	FOT West Main Q3	-	-	-	-	-	21	50	50	43	-	-	-	-	-	-	-	-	-	50	50	16	13
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	247	208	99	-	99	160	53	187	N/A	132
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	89	97	-	-	392	423	65	169	N/A	154
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	114	119	172	257	173	119	45	-	N/A	125
	Annual Additions, Long Term Resources	267	829	693	1,301	261	300	895	375	261	1,658	808	97	98	99	101	116	107	98	100	98		
	Annual Additions, Short Term Resources	-	-	129	601	648	749	709	891	967	604	739	800	941	1,049	1,180	1,231	1,392	1,548	1,702	1,872		
	Total Annual Additions	267	829	823	1,902	909	1,049	1,604	1,266	1,227	2,261	1,547	897	1,039	1,148	1,281	1,347	1,499	1,646	1,802	1,969		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 4

PVRR: $34,612

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Total Wind	99	99	-	-	-	-	140	-	160	-	-	-	-	-	-	-	-	-	-	-	498	498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	-	-	-	-	8	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	16	37
	DSM, Class 2, UT	37	46	42	42	43	44	43	41	45	47	47	48	49	51	52	52	50	53	54	52	431	939
	DSM, Class 2, WY	-	3	6	8	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	66	162
	DSM, Class 2 Total	38	50	49	52	53	54	53	51	56	58	58	59	60	62	64	64	63	66	66	64	513	1,138
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	104	3	-	-	-	-	-	-	-	-	-	10	5
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	288	491
	DSM, Class 2, YA	4	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	369	662
	FOT COB Flat	-	-	-	213	-	222	102	189	147	239	338	275	231	201	190	186	329	338	321	-	111	176
	FOT COB Q3	-	-	-	-	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	299	23	26
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	90	119	148	146	-	-	-	-	-	-	-	-	21	25
	FOT MidColumbia Q3	-	-	-	123	96	99	94	89	-	-	-	-	-	-	-	-	-	-	-	-	50	25
	FOT West Main Q3	-	-	-	-	-	-	-	-	-	13	-	-	50	50	50	-	-	-	18	50	1	12
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	15	14	33	31	43	N/A	18
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	144	140	137	101	105	82	83	68	N/A	108
	Annual Additions, Long Term Resources	253	316	178	998	182	149	252	118	275	107	89	90	93	94	96	96	438	96	96	94		
	Annual Additions, Short Term Resources	-	-	-	335	322	321	197	278	237	475	488	421	425	391	381	302	448	452	453	461		
	Total Annual Additions	253	316	178	1,333	504	471	449	396	512	582	577	511	518	485	476	398	887	548	549	555		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05

PVRR: $40,526

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	750	400	-	150	-	-	-	-	-	-	-	750	1,300
	Total Wind	99	99	-	-	-	-	300	-	-	750	400	-	150	-	-	-	-	-	-	-	1,248	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	446	970
	DSM, Class 2, WY	-	2.6	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	67	164
	DSM, Class 2 Total	42	50.3	49	52	55	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	531	1,172
	FOT Utah Q3	-	-	-	-	-	-	-	25	-	-	-	-	50	50	-	-	-	-	50	-	2	9
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Mona/Nevada Utah Border	-	-	-	121	200	200	200	200	64	200	200	200	200	200	200	200	200	200	200	200	119	159
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	199	200	198	219	-	-	183	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	2	106	249	341	-	-	111	-	N/A	101
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	3	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	4	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	370	663
	FOT COB Flat	-	-	220	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	201	252
	FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	171	276	313	379	71	151	189	141	400	400	400	400	45	165
	FOT MidColumbia Q3	-	-	-	156	178	296	396	400	-	-	-	-	-	-	-	-	-	-	-	-	143	71
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	118	123	130	133	124	135	153	149	N/A	133
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	498	215	887	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	80	-	-	-	194	243	319	164	N/A	125
	Annual Additions, Long Term Resources	256	317	178	998	187	152	415	385	118	858	490	91	242	94	95	95	446	97	98	97		
	Annual Additions, Short Term Resources	-	-	220	716	817	935	936	914	1,004	1,365	1,500	1,566	1,707	1,818	1,954	2,021	2,306	2,463	2,618	2,788		
	Total Annual Additions	256	317	398	1,713	1,004	1,088	1,351	1,299	1,122	2,223	1,990	1,657	1,949	1,912	2,049	2,116	2,752	2,559	2,716	2,885		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 06

PVRR: $48,140

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCCT H 2x1	-	-	-	-	-	-	-	-	-	475	-	475	-	-	-	-	-	-	-	-	475	950
	IC Aero	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	354	-	251	-	-	696	-	-	-	-	-	-	-	604	1,300
	Total Wind	99	99	-	-	-	140	160	354	-	251	-	-	696	-	-	-	-	-	-	-	1,102	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	4	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	101	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	40
	DSM, Class 2, UT	43	48.7	44	48	49	52	51	52	52	51	55	54	56	58	59	73	64	62	60	60	490	1,091
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	172
	DSM, Class 2 Total	45	53.3	52	58	59	62	61	63	63	61	66	65	68	70	71	85	77	75	73	73	579	1,303
	Fuel Cell	-	-	-	-	5	5	-	30	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	-	18	50	-	50	-	-	-	-	50	50	50	50	50	50	50	50	12	26
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	497	600	480	600	600	600	600	600	600	600	600	98	343
	FOT Mona/Nevada Utah Border	-	39	79	200	200	200	99	200	166	200	200	144	200	200	200	200	200	200	200	200	138	166
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	95	114	174	122	99	199	197	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	63	249	-	-	470	217	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	21	127	211	129	-	249	263	N/A	125
West																							
	CCCT F 2x1	-	-	-	-	-	-	627	-	-	-	-	-	-	-	-	-	-	-	-	-	627	627
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	-	-	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	2	-	-	-	-	-	-	-	24	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 06

PVRR: $48,140

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	21	21	21	21	21	290	496
DSM, Class 2, YA	5	6	6	5	6	6	6	6	5	6	6	6	6	6	7	7	7	7	7	7	56	122
DSM, Class 2 Total	35	37.2	39	39	39	40	40	40	39	29	30	30	30	29	30	31	30	30	31	31	378	680
FOT COB Flat	-	-	389	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	218	261
FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	244	302	395	370	400	400	400	400	400	400	400	400	55	225
FOT MidColumbia Q3	-	-	-	202	400	400	206	400	-	-	-	-	-	-	-	-	-	-	-	-	161	80
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	35	169	190	182	184	297	442	502	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381	763	147	709	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	40	148	64	417	430	445	456	N/A	250
Annual Additions, Long Term Resources	266	327	188	1,272	214	506	940	546	123	836	98	572	801	101	102	118	107	106	104	104		
Annual Additions, Short Term Resources	-	39	469	841	1,058	1,089	644	939	1,179	1,288	1,582	1,381	1,673	1,962	2,279	2,517	2,870	3,226	3,591	3,982		
Total Annual Additions	266	366	656	2,113	1,271	1,595	1,584	1,485	1,302	2,124	1,681	1,953	2,474	2,063	2,382	2,635	2,977	3,332	3,695	4,086		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 7

PVRR: $34,582

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	27	400	207	590	-	76	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	27	400	346	750	-	76	-	-	-	-	-	-	-	-	-	-	-	1,798	1,798
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	1	-	-	-	8	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	49	44	45	45	46	46	45	47	48	47	48	54	56	52	52	50	53	54	55	457	978
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	70	166
	DSM, Class 2 Total	45	53	52	55	56	56	56	56	58	59	58	59	65	67	64	64	63	66	66	67	544	1,183
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	2	1
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	100	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	-	25	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	1	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
	DSM, Class 2, YA	5	6	6	5	5	6	6	5	6	6	6	6	6	6	7	7	7	7	7	7	56	121
	DSM, Class 2 Total	36	37	39	39	39	39	39	39	40	29	30	30	30	29	30	31	30	30	30	30	376	675
	FOT COB Flat	-	-	-	-	203	187	36	118	52	239	243	177	180	146	134	81	105	113	115	-	83	106
	FOT COB Q3	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	20	30
	FOT Mid Columbia Flat	-	-	-	-	89	92	87	82	82	111	139	138	-	-	-	-	-	-	-	-	54	41
	FOT MidColumbia Q3	-	-	-	121	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	6
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	N/A	1
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	136	131	132	107	109	105	104	89	N/A	114
	Annual Additions, Long Term Resources	261	320	181	1,028	686	499	890	123	219	209	90	91	97	99	96	97	94	96	97	444		
	Annual Additions, Short Term Resources	-	-	-	321	292	279	123	201	134	370	382	315	316	277	267	187	214	218	218	501		
	Total Annual Additions	261	320	181	1,349	978	778	1,013	324	352	579	473	406	413	377	363	285	308	314	315	944		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 8

PVRR: $41,372

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	193	107	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	264	300	146	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	264	300	286	750	193	158	249	-	-	-	-	-	-	-	-	-	-	2,398	2,398
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	5	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	66	66
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	16	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	49	51	51	50	52	51	55	54	54	56	58	62	59	55	57	56	484	1,049
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	171
	DSM, Class 2 Total	45	54	52	55	60	62	62	61	64	63	66	65	66	68	70	74	72	68	70	68	577	1,264
	FOT Mona Q3	-	-	-	89	189	200	200	200	78	200	200	200	200	200	200	200	200	200	200	200	116	158
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	40	-	-	-	-	-	-	5	4
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	153	148	145	163	-	11	35	83	N/A	92
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	167	-	-	-	-	N/A	31
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	22	22
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	496
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	56	122
	DSM, Class 2 Total	36	37	39	39	39	39	39	40	40	30	30	30	30	29	30	31	30	30	30	30	378	678
	FOT COB Flat	-	-	200	-	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	199	251
	FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	39	39
	FOT Mid Columbia Flat	-	-	-	-	130	220	281	400	163	269	313	373	18	331	400	265	400	400	400	293	146	233
	FOT MidColumbia Q3	-	-	-	154	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	100	114	132	112	119	128	208	N/A	126
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82	172	464	413	870	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	246	2	14	-	291	137	309	-	N/A	125
	Annual Additions, Long Term Resources	263	327	187	1,277	698	450	908	394	283	362	99	97	98	100	101	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	-	200	683	758	859	821	939	1,010	1,358	1,500	1,561	1,701	1,808	1,939	1,998	2,163	2,318	2,473	2,704		
	Total Annual Additions	263	327	387	1,959	1,456	1,309	1,729	1,333	1,293	1,720	1,599	1,658	1,799	1,908	2,041	2,104	2,264	2,417	2,573	2,802		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 09

PVRR: $40,204

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	444	536	305	15	-	-	-	-	-	-	-	-	980	1,300
	Total Wind	99	99	-	-	-	-	300	-	444	536	305	15	-	-	-	-	-	-	-	-	1,478	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	43	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	444	968
	DSM, Class 2, WY	-	3.1	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	68	164
	DSM, Class 2 Total	42	50.8	49	52	53	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	529	1,171
	FOT Utah Q3	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	3	1
	FOT Mead Q3	-	-	-	-	-	-	-	-	307	480	512	577	600	600	600	600	600	600	600	600	79	334
	FOT Mona/Nevada Utah Border	-	-	-	-	-	98	198	200	-	192	200	200	200	200	200	200	200	200	200	200	69	134
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	2	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	4	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	370	663
	FOT COB Flat	-	-	220	389	-	-	289	239	239	239	338	338	338	338	-	-	-	-	338	-	162	165
	FOT COB Q3	-	-	-	-	389	389	-	-	-	-	-	-	-	-	338	338	338	338	-	338	78	123
	FOT MidColumbia Q3	-	-	-	326	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	273	336
	FOT West Main Q3	-	-	-	-	29	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	28	39
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	118	123	130	124	124	128	221	407	N/A	172
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	306	287	436	492	474	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	3	110	234	5	309	313	319	321	N/A	202
	Annual Additions, Long Term Resources	256	317	178	998	185	152	415	385	562	645	394	105	93	94	95	96	446	97	98	97		
	Annual Additions, Short Term Resources	-	-	220	716	818	937	938	916	996	1,362	1,499	1,565	1,709	1,820	1,956	2,023	2,307	2,464	2,619	2,789		
	Total Annual Additions	256	317	398	1,713	1,003	1,089	1,353	1,300	1,558	2,007	1,894	1,670	1,801	1,914	2,051	2,118	2,753	2,561	2,718	2,886		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 10

PVRR: $40,319

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	52	248	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	194	106	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	361	151	590	197	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	361	291	750	391	158	248	200	-	-	-	-	-	-	-	-	-	2,398	2,598
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	6	8	4	4	-	-	-	-	-	-	-	-	-	-	44	44
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	16	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	41	49	44	45	45	51	51	50	53	51	55	54	54	56	58	62	59	55	57	56	478	1,043
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	171
	DSM, Class 2 Total	43	54	52	55	56	62	62	61	64	63	66	65	66	68	70	74	72	68	70	68	571	1,257
	FOT Mona Q3	-	-	-	-	-	63	177	200	78	200	200	200	200	200	200	200	200	200	200	200	72	136
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	531	577	587	600	600	600	600	600	600	600	96	343
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	3	1	1	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	495
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	57	122
	DSM, Class 2 Total	35	37	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	378	679
	FOT COB Flat	-	-	213	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	239	288
	FOT MidColumbia Q3	-	-	-	316	371	400	400	400	162	389	400	400	400	400	400	400	400	400	400	400	244	322
	FOT West Main Q3	-	-	-	-	37	50	-	50	50	50	-	14	50	50	50	50	50	50	50	50	24	33
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	121	116	131	122	130	137	148	N/A	125
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	216	332	450	372	526	N/A	237
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	50	177	-	89	109	309	266	N/A	125
	Annual Additions, Long Term Resources	259	321	182	1,002	550	451	911	827	283	362	299	97	98	99	101	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	-	213	705	798	902	867	939	1,010	1,358	1,468	1,529	1,669	1,777	1,908	1,966	2,131	2,287	2,441	2,610		
	Total Annual Additions	259	321	395	1,707	1,348	1,353	1,778	1,766	1,293	1,719	1,767	1,626	1,767	1,876	2,010	2,073	2,233	2,385	2,541	2,709		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 11

PVRR: $40,559

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	14	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	133	-	-	-	-	-	-	-	-	-	-	133	133
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	12	352	617	185	-	-	-	-	-	-	-	-	-	981	1,167
	Wind, WYSW, 35	-	-	64	300	286	224	425	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	64	300	500	650	585	12	652	750	185	-	-	-	-	-	-	-	-	-	3,712	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	-	-	-	-	-	8	19
	CHP - Kern River	-	-	-	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	47	55	49	49	52	53	53	52	53	57	55	56	56	58	59	73	64	62	57	56	520	1,116
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	73	175
	DSM, Class 2 Total	50	61	57	59	63	64	64	63	65	69	67	67	68	70	71	86	77	75	70	68	616	1,335
	FOT Mona Q3	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	20	10
	FOT Mead Q3	-	-	-	-	-	-	-	-	276	87	128	187	40	125	239	424	433	165	-	-	36	105
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	62	38	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	2	100	98	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	-	200	-	100	165	738	98	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	6	6	61	128
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	30	30	30	30	385	689
	FOT COB Flat	-	-	196	-	-	389	289	239	-	-	-	-	-	338	-	-	-	-	-	-	111	73
	FOT COB Q3	-	-	-	389	389	-	-	-	239	239	338	338	338	-	338	338	400	400	400	-	126	207
	FOT MidColumbia Q3	-	-	-	285	273	344	400	400	400	400	400	400	400	400	400	400	400	400	400	118	250	311
	FOT West Main Q3	-	-	-	-	-	-	-	24	-	-	-	-	-	-	-	-	50	50	50	50	2	11
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	288	439	615	637	N/A	250
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	256	480	1,264	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	285	290	293	133	-	-	-	-	N/A	125
	Annual Additions, Long Term Resources	267	329	251	1,512	765	918	900	907	876	1,476	285	99	101	102	104	117	108	106	100	98		
	Annual Additions, Short Term Resources	-	-	196	674	663	733	689	863	915	726	866	925	1,063	1,168	1,298	1,348	1,571	1,721	1,980	2,152		
	Total Annual Additions	267	329	447	2,186	1,427	1,651	1,589	1,770	1,791	2,202	1,151	1,024	1,164	1,270	1,402	1,465	1,679	1,827	2,080	2,250		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 12

PVRR: $50,146

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	108	-	-	-	-	-	-	-	95	97	-	-	-	-	-	-	-	108	300
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	135	65	-	-	-	-	-	-	-	-	-	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	334	300	199	468	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	441	300	338	628	-	-	-	135	161	97	-	-	-	-	-	-	-	1,905	2,297
	Battery Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	15
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	4	-	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	22.6	-	7.3	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	37	10	71	10	25	10	10	-	-	8	-	-	-	-	-	-	-	288	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	47	55.1	49	49	52	53	52	52	53	57	55	60	61	63	65	89	65	68	68	62	520	1,176
	DSM, Class 2, WY	1	3.4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	11	73	176
	DSM, Class 2 Total	50	60.4	57	59	63	64	63	63	64	68	67	72	73	75	77	102	78	81	81	75	612	1,393
	FOT Utah Q3	-	-	-	-	-	50	-	50	-	-	-	50	50	50	50	50	50	50	50	50	10	28
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	515	600	600	600	600	600	600	600	600	600	96	344
	FOT Mona/Nevada Utah Border	-	30	67	200	200	200	141	200	168	157	200	200	200	200	200	200	200	200	200	200	136	168
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	107	166	153	203	148	17	88	118	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	479	401	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	14	86	124	214	225	-	97	240	N/A	125
West																							
	CCCT F 2x1	-	-	-	-	-	-	627	-	-	-	-	-	-	-	-	-	-	-	-	-	627	627
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	385	-	-	790
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	2	-	-	-	-	-	-	-	-	24	25

Case 12

PVRR: $50,146

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	2.9	-	-	-	-	1.2	-	-	-	-	-	-	-	2.9	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	5.8
DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	21	-	3	-	-	-	-	10	-	-	-	-	-	-	-	24	34
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	498
DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
DSM, Class 2 Total	36	37.2	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	382	689
FOT COB Flat	-	-	389	-	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	218	261
FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	39	39
FOT Mid Columbia Flat	-	-	-	-	303	400	202	400	239	297	342	400	400	400	400	400	400	400	400	400	184	289
FOT MidColumbia Q3	-	-	-	398	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	20
FOT West Main Q3	-	-	-	50	50	50	-	50	50	-	50	50	50	50	50	50	50	50	50	50	25	38
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	157	179	161	181	184	289	308	542	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	714	526	675	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	1	132	317	24	409	422	437	258	N/A	250
Annual Additions, Long Term Resources	271	333	193	1,467	1,032	588	1,415	180	126	719	235	270	221	107	109	134	109	517	497	121		
Annual Additions, Short Term Resources	-	30	457	1,037	943	1,089	633	939	1,177	1,173	1,445	1,638	1,916	2,201	2,513	2,737	3,089	3,079	3,094	3,533		
Total Annual Additions	271	363	650	2,504	1,974	1,678	2,048	1,119	1,303	1,892	1,680	1,908	2,138	2,308	2,622	2,872	3,198	3,596	3,591	3,654		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 13

PVRR: $31,076

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	250	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	92	108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	286	24	-	165	-	-	-	-	-	-	-	286	476
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	101	161	224	339	-	-	-	-	-	-	-	-	-	-	824	824
	Wind, WYSW, 35	-	308	42	54	151	394	350	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	499	400	104	151	394	750	161	224	625	24	-	165	-	-	-	-	-	-	-	3,408	3,598
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	55	49	51	52	53	52	52	53	57	55	55	56	58	59	73	64	62	60	60	523	1,126
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	73	173
	DSM, Class 2 Total	50	61	57	62	63	64	63	63	64	68	67	67	68	70	71	85	77	75	73	72	615	1,340
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	296	49	156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	120	100	396	349	356	-	100	-	-	-	-	-	-	-	-	-	-	-	-	1,465	1,465
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	65
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	291	496
	DSM, Class 2, YA	6	7	6	6	6	6	6	7	7	7	7	7	7	7	7	8	7	7	7	7	65	136
	DSM, Class 2 Total	37	39	40	40	40	40	40	41	40	30	31	31	31	30	31	32	31	31	31	31	389	698
	FOT COB Q3	-	-	-	193	400	127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Mid Columbia Flat	-	-	-	110	71	66	60	52	52	80	108	106	-	-	-	-	-	-	-	-	49	35
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	103	98	98	72	74	70	68	65	N/A	81
	Annual Additions, Long Term Resources	267	829	694	1,515	765	911	897	416	347	1,341	122	97	264	100	102	117	108	106	104	103		
	Annual Additions, Short Term Resources	-	-	-	303	471	193	60	52	52	80	108	106	103	98	98	72	74	70	68	65		
	Total Annual Additions	267	829	694	1,818	1,236	1,105	957	469	399	1,421	230	203	367	198	200	189	182	176	172	168		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 14

PVRR: $39,949

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	238	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	101	-	100	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	174	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	55	68	185	191	-	-	-	-	-	-	-	55	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	291	-	-	-	-	-	-	-	-	-	-	291	291
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	267	14	207	-	-	-	-	-	-	-	-	487
	Wind, WYSW, 29	-	-	-	-	-	-	-	351	382	276	-	-	-	-	-	-	-	-	-	-	1,009	1,009
	Wind, WYSW, 35	-	320.5	42	66	193	229	451	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	594	305	128	193	329	750	750	382	622	335	199	398	-	-	-	-	-	-	-	4,153	5,085
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	-	-	-	-	-	8	19
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2.0	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59.0	49	52	53	53	53	52	53	57	55	56	61	63	59	73	65	62	60	60	530	1,145
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	64.7	58	62	64	64	64	63	65	69	67	67	73	75	71	86	77	76	73	73	627	1,366
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	480	480	445	480	178	491	452	480	500	600	96	277
	FOT Mona/Nevada Utah Border	-	-	-	4	52	182	200	200	14	-	-	-	-	44	-	200	-	104	200	200	65	70
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	94	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	5	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	272	13	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	25.0	195	372	307	421	-	-	100	-	-	-	-	-	-	-	-	-	-	-	1,465	1,465
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	3	4	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	3	34	66
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
	DSM, Class 2, YA	6	7	6	6	6	6	6	7	7	7	7	7	7	7	7	8	7	7	7	7	65	136
	DSM, Class 2 Total	37	38.7	40	40	40	41	40	41	41	30	31	31	31	31	31	32	31	31	31	31	391	701
	FOT COB Flat	-	-	-	-	-	-	289	-	-	25	-	179	338	338	338	-	-	-	-	-	31	75
	FOT COB Q3	-	-	122	389	400	389	-	239	239	-	129	-	-	-	-	338	338	338	338	338	178	180
	FOT Mid Columbia Flat	-	-	-	143	113	118	122	301	132	174	210	218	2	13	-	-	63	63	146	154	110	99
	FOT West Main Q3	-	-	-	50	50	-	40	50	-	-	-	-	-	-	-	-	-	-	-	9	19	10
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	9	83	153	-	41	116	117	N/A	65
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	-	-	-	-	-	N/A	57
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	224	210	161	76	181	147	-	-	N/A	125
	Annual Additions, Long Term Resources	271	833	700	1,511	766	913	900	909	609	1,350	436	299	506	108	104	117	574	106	104	104		
	Annual Additions, Short Term Resources	-	-	122	586	615	689	651	790	866	679	819	877	1,009	1,110	1,240	1,290	1,034	1,183	1,335	1,500		
	Total Annual Additions	271	833	823	2,097	1,381	1,602	1,551	1,699	1,475	2,028	1,255	1,176	1,515	1,218	1,344	1,407	1,608	1,290	1,439	1,603		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 15

PVRR: $50,914

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	86	-	-	214	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	213	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	167	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	750	100	-	-	-	-	-	-	-	-	51	900
	Wind, WYSW, 29	-	-	-	-	-	-	15	336	750	200	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	333.4	54	87	214	176	436	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	174	300	176	750	750	750	750	750	100	-	-	-	-	-	-	-	-	4,648	5,497
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	4	-	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	2.3	-	-	-	4.0	-	-	-	-	-	-	-	-	2.3	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	17	10	10	90	10	10	-	4	-	-	-	-	-	-	-	-	292	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	20	43
	DSM, Class 2, UT	54	64.0	56	57	58	58	60	57	60	61	60	60	62	63	65	89	65	62	60	60	587	1,233
	DSM, Class 2, WY	1	3.9	6	9	9	10	10	9	10	10	10	10	10	11	10	10	10	11	11	10	78	182
	DSM, Class 2 Total	57	69.9	65	68	69	70	71	69	72	73	72	72	74	76	77	102	77	76	73	73	685	1,457
	Solar	-	-	-	-	-	250	250	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	FOT Utah Q3	-	-	-	-	25	50	50	50	-	-	-	50	-	-	-	-	-	-	-	50	17	14
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	585	600	600	600	600	600	480	583	600	600	96	340
	FOT Mona/Nevada Utah Border	-	-	-	200	200	200	200	200	179	160	200	200	200	200	200	200	20	200	200	200	134	158
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	18	-	-	79	-	-	11	289	N/A	49
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	171	N/A	21
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	226	-	274	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20.0	200	326	200	574	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	2	-	-	-	-	-	-	-	-	24	25

Case 15

PVRR: $50,914

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	1.0	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	5.5
DSM, Class 1, WM-Irrigate	-	-	-	-	-	7.4	-	5.1	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	8	7	12	-	-	-	7	-	-	-	-	-	-	-	-	27	34
DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	34	67
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	20	21	21	21	21	21	294	501
DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	7	66	138
DSM, Class 2 Total	37	38.7	41	41	41	41	41	42	41	31	31	31	31	31	31	32	31	31	31	31	394	705
FOT COB Flat	-	-	-	-	-	-	289	-	-	239	-	338	338	338	338	-	-	-	-	-	53	94
FOT COB Q3	-	-	367	389	400	389	-	239	239	-	338	-	-	-	-	338	338	338	338	338	202	202
FOT Mid Columbia Flat	-	-	-	301	400	400	400	400	212	269	314	400	400	400	236	400	400	400	400	400	238	307
FOT West Main Q3	-	-	-	50	50	50	50	50	50	-	-	50	50	50	-	50	-	50	50	50	30	33
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	110	120	165	264	-	47	150	147	N/A	125
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	32	438	999	530	-	-	-	-	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	196	82	-	302	34	8	243	139	N/A	125
Annual Additions, Long Term Resources	281	844	715	1,522	785	1,183	1,170	1,273	884	1,475	855	221	107	109	110	135	2,175	106	104	104		
Annual Additions, Short Term Resources	-	-	367	940	1,075	1,089	989	939	1,160	1,148	1,437	1,638	1,943	2,227	2,538	2,763	1,271	1,626	1,991	2,383		
Total Annual Additions	281	844	1,082	2,462	1,860	2,273	2,160	2,212	2,045	2,624	2,292	1,859	2,051	2,335	2,648	2,898	3,445	1,733	2,095	2,486		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 16

PVRR: $43,523

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	112	88	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	403	-	-	-	-	-	-	-	-	-	-	403	403
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	305	384	208	-	-	-	-	-	-	-	-	-	-	-	897	897
	Wind, WYSW, 35	-	-	104	300	201	638	57	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	104	300	500	750	750	384	208	403	-	-	-	-	-	-	-	-	-	-	3,597	3,597
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	43	49	44	48	49	51	51	50	53	51	55	54	54	58	59	73	65	62	60	60	489	1,088
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	73	173
	DSM, Class 2 Total	46	54	52	59	60	62	62	61	64	62	66	65	66	70	71	85	77	76	73	73	580	1,302
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	30	31	31	31	31	31	31	20	21	20	20	20	20	21	21	21	21	21	291	496
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	381	687
	FOT COB Flat	-	-	-	-	-	118	-	-	-	74	51	-	-	-	-	-	-	171	167	172	19	38
	FOT COB Q3	-	-	-	192	116	7	-	-	-	-	-	-	-	-	-	-	170	-	-	-	32	24
	FOT Mid Columbia Flat	-	-	-	-	88	91	85	80	80	108	137	135	-	-	-	-	-	-	-	-	53	40
	FOT MidColumbia Q3	-	-	-	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	6
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	N/A	1
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	132	128	129	103	105	100	99	87	N/A	110
	Annual Additions, Long Term Resources	262	321	286	1,518	762	910	898	539	332	516	99	98	99	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	-	-	308	204	217	85	80	80	183	188	135	132	128	129	103	275	271	266	267		
	Total Annual Additions	262	321	286	1,826	966	1,127	983	619	412	699	288	233	231	230	231	221	1,259	378	370	371		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 17

PVRR: $51,207

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	14	-	-	286	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	151	-	-	-	-	-	-	-	-	-	-	151	151
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	394	595	59	101	-	-	-	-	-	-	-	-	-	-	1,149	1,149
	Wind, WYSW, 35	-	-	194	286	201	600	20	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	194	300	500	750	750	595	110	500	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	55	49	49	49	51	51	52	53	57	55	56	56	58	59	73	65	62	60	60	508	1,112
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	73	175
	DSM, Class 2 Total	46	61	57	59	60	62	62	63	65	69	67	67	68	70	71	86	77	76	73	73	603	1,332
	FOT Mona Q3	-	-	-	85	119	182	200	200	67	200	200	200	200	200	200	200	200	200	200	200	105	153
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	30	163	-	11	190	83	N/A	62
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	7	-	N/A	3
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	497
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	382	688
	FOT COB Flat	-	-	197	-	-	288	289	239	239	239	338	338	338	338	338	-	-	338	338	338	149	210
	FOT COB Q3	-	-	-	389	389	101	-	-	-	-	-	-	-	-	-	338	338	-	-	-	88	78
	FOT Mid Columbia Flat	-	-	-	-	129	143	161	386	161	203	241	300	331	400	400	400	400	400	400	400	118	243
	FOT MidColumbia Q3	-	-	-	149	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7
	FOT West Main Q3	-	-	-	50	50	50	50	50	-	45	50	50	50	50	50	50	50	50	50	50	29	40
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	107	121	127	107	187	237	236	233	N/A	169
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	486	467	370	677	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	6	116	36	105	212	276	250	N/A	125
	Annual Additions, Long Term Resources	262	328	381	1,519	762	910	898	752	243	620	100	100	101	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	-	197	673	688	764	701	875	947	1,287	1,429	1,487	1,625	1,731	1,861	1,910	2,365	2,515	2,666	2,831		
	Total Annual Additions	262	328	578	2,192	1,450	1,674	1,599	1,628	1,191	1,907	1,529	1,587	1,726	1,833	1,964	2,029	3,349	2,621	2,770	2,934		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 18

PVRR: $49,745

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	52	248	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	100	698	2	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	-	-	263	201	750	86	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	263	500	750	286	400	750	750	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	41	49	44	45	49	51	51	50	53	51	55	54	54	56	59	73	64	62	60	60	482	1,079
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	172
	DSM, Class 2 Total	43	54	52	55	60	62	62	61	64	63	66	65	66	68	71	85	77	75	73	72	576	1,295
	FOT Mona Q3	-	-	-	-	-	-	31	200	-	144	185	200	200	184	200	200	200	200	200	200	37	117
	FOT Mead Q3	-	-	-	-	-	-	-	-	305	480	480	526	480	480	600	480	600	600	600	600	79	312
	FOT Utah Q3	-	-	-	-	-	-	-	14	-	-	-	-	-	-	-	-	-	-	50	50	1	6
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	190	180	N/A	57
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	166	682	N/A	106
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	496
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	57	122
	DSM, Class 2 Total	35	37	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	378	679
	FOT COB Flat	-	-	213	389	-	-	289	239	-	-	338	338	338	338	338	-	338	338	338	338	113	208
	FOT COB Q3	-	-	-	-	345	389	-	-	239	239	-	-	-	-	-	338	-	-	-	-	121	77
	FOT MidColumbia Q3	-	-	-	310	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	271	335
	FOT West Main Q3	-	-	-	-	-	21	30	50	24	47	50	50	50	50	50	50	50	50	50	50	17	34
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	116	122	128	131	122	127	134	147	N/A	128
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	70	172	123	229	515	518	262	111	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	82	173	303	309	107	N/A	125
	Annual Additions, Long Term Resources	259	322	182	1,277	728	945	634	555	881	863	99	97	98	99	102	118	983	106	103	103		
	Annual Additions, Short Term Resources	-	-	213	699	745	810	749	903	969	1,310	1,453	1,514	1,654	1,762	1,892	1,942	2,397	2,547	2,699	2,864		
	Total Annual Additions	259	322	395	1,976	1,472	1,755	1,384	1,459	1,849	2,173	1,552	1,610	1,752	1,861	1,995	2,060	3,381	2,653	2,802	2,967		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 19

PVRR: $50,102

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	16	16
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	201	750	333	-	-	-	-	-	-	-	-	-	-	-	1,284	1,284
	Wind, WYSW, 35	-	-	-	400	201	650	50	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	400	500	650	750	750	385	265	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	48	49	49	51	51	50	53	57	55	56	56	58	59	73	65	62	60	60	500	1,104
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	72	174
	DSM, Class 2 Total	45	54	56	59	60	62	62	61	65	68	67	67	68	70	71	86	77	76	73	73	594	1,322
	FOT Mona Q3	-	-	-	-	-	-	18	200	-	168	200	200	200	200	200	200	200	200	200	200	39	119
	FOT Mead Q3	-	-	-	-	-	-	-	-	305	480	492	551	544	600	585	556	600	600	600	600	78	326
	FOT Utah Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	116	180	N/A	48
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	471	N/A	59
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WM, 35	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	100	-	100	-	-	200	-	-	-	-	-	-	-	-	-	-	-	465	465
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	63
	DSM, Class 2, WM	28	28	30	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	497
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	381	688
	FOT COB Flat	-	-	207	389	-	-	289	239	239	239	338	338	338	338	338	-	-	-	-	-	160	165
	FOT COB Q3	-	-	-	-	389	389	-	-	-	-	-	-	-	-	-	338	338	338	400	400	78	130
	FOT MidColumbia Q3	-	-	-	292	306	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	260	330
	FOT West Main Q3	-	-	-	-	-	5	-	42	-	-	-	-	50	50	50	50	50	50	50	50	5	22
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	94	121	128	130	127	144	131	147	N/A	128
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	7	134	206	362	479	534	279	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	290	294	299	118	N/A	125
	Annual Additions, Long Term Resources	262	322	187	1,519	764	910	898	905	716	384	100	100	101	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	-	207	682	695	794	707	881	944	1,287	1,429	1,488	1,626	1,732	1,862	1,911	2,366	2,516	2,729	2,894		
	Total Annual Additions	262	322	393	2,201	1,459	1,704	1,605	1,787	1,660	1,671	1,529	1,588	1,727	1,834	1,965	2,030	3,350	2,622	2,833	2,998		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 20

PVRR: $50,536

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	-	-	-	-	53	247	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	32	-	245	23	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	51	326	123	-	-	-	-	-	-	-	-	51	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	133	253	-	-	-	-	-	-	-	-	-	-	386	386
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	424	476	-	-	-	-	-	-	-	-	-	900
	Wind, WYSW, 29	-	-	-	-	-	-	368	182	363	-	-	-	-	-	-	-	-	-	-	-	914	914
	Wind, WYSW, 35	-	-	344	224	201	505	26	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	344	456	500	750	418	182	550	750	750	600	-	-	-	-	-	-	-	-	4,148	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	-	-	-	-	-	9	19
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	47	55	49	51	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	56	524	1,123
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	68	620	1,344
	FOT Mona Q3	-	-	-	-	-	-	-	200	-	58	101	159	-	-	-	151	-	-	-	-	26	33
	FOT Mead Q3	-	-	-	-	-	-	-	-	275	480	480	480	-	189	346	480	139	277	-	-	75	157
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	232	268	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	56	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	156	44	-	-	332	568	200	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	6	62	129
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	30	30	387	691
	FOT COB Flat	-	-	184	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	9
	FOT COB Q3	-	-	-	389	400	320	285	239	239	239	338	338	400	400	400	400	400	400	400	400	211	299
	FOT MidColumbia Q3	-	-	-	241	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	264	332
	FOT West Main Q3	-	-	-	-	-	-	-	16	-	50	50	50	-	-	-	50	-	-	-	-	7	11
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	273	181	92	94	-	-	363	998	N/A	250
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	389	257	304	50	-	-	66	934	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	164	289	292	254	-	-	-	-	N/A	125
	Annual Additions, Long Term Resources	267	329	688	1,522	766	913	900	907	882	869	849	699	101	102	104	117	2,584	106	104	98		
	Annual Additions, Short Term Resources	-	-	184	631	800	720	685	855	914	1,228	1,368	1,426	1,626	1,732	1,862	1,912	939	1,088	1,264	2,814		
	Total Annual Additions	267	329	872	2,153	1,566	1,633	1,585	1,762	1,797	2,097	2,218	2,125	1,728	1,834	1,965	2,029	3,522	1,194	1,367	2,912		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 21

PVRR: $40,517

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	251	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	93	107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	151	339	-	-	-	-	-	-	-	-	-	151	489
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	229	200	-	-	-	-	-	-	-	-	-	-	429	429
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	101	750	21	-	-	-	-	-	-	-	-	-	-	-	871	871
	Wind, WYSW, 35	-	307	42	59	361	196	335	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	499	400	108	500	356	436	750	750	350	339	-	-	-	-	-	-	-	-	-	4,248	4,587
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	20	42
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	530	1,134
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	68	67	67	68	70	71	86	77	76	73	73	625	1,353
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	480	480	0	48
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	292	-	94	114	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	113	-	-	-	-	-	-	-	-	-	-	113
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	120	100	392	-	394	314	-	-	400	113	-	-	-	-	-	-	-	-	-	1,765	1,878
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
	DSM, Class 2, YA	6	7	6	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	139
	DSM, Class 2 Total	37	39	40	40	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	392	705
	FOT COB Q3	-	-	-	192	116	126	-	-	400	-	-	-	-	-	-	-	-	-	-	-	84	42
	FOT Mid Columbia Flat	-	-	-	110	82	73	60	54	53	72	97	94	-	-	-	-	-	-	-	-	50	35
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	92	87	87	61	63	58	57	52	N/A	70
	Annual Additions, Long Term Resources	271	833	694	1,516	766	912	898	906	874	867	550	98	100	101	102	117	2,585	107	104	106		
	Annual Additions, Short Term Resources	-	-	-	302	198	200	60	54	453	72	97	94	92	87	87	61	63	58	537	532		
	Total Annual Additions	271	833	694	1,818	964	1,112	958	960	1,327	939	647	192	191	187	189	178	2,647	165	641	638		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 22

PVRR: $49,983

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	238	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	118	82	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	179	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	376	124	-	-	-	-	-	-	-	-	-	376	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	66	200	-	-	-	-	-	-	-	-	-	-	265	265
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	376	524	-	-	-	-	-	-	-	-	-	900
	Wind, WYSW, 29	-	-	-	-	-	-	101	632	303	-	-	-	-	-	-	-	-	-	-	-	1,035	1,035
	Wind, WYSW, 35	-	321	41	90	361	238	249	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	152	500	398	350	750	750	575	501	524	-	-	-	-	-	-	-	-	4,473	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	-	-	-	-	-	-	-	-	-	-	-	5	5
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59	49	52	53	58	60	57	60	61	60	60	61	63	65	73	65	62	60	60	559	1,188
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	177
	DSM, Class 2 Total	53	65	58	63	64	69	71	68	72	73	71	72	74	75	77	86	77	76	73	73	656	1,410
	FOT Mona Q3	-	-	-	16	43	132	193	200	-	-	-	-	-	28	131	192	-	-	-	-	58	47
	FOT Mead Q3	-	-	-	-	-	-	-	-	423	480	480	480	480	480	480	480	53	185	480	480	90	249
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	75	225	-	-	-	-	-	-	-	-	-	75	300
	Wind, YA, 29 PPA	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	248	-	152	100	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	24	176	-	-	-	-	-	-	-	-	-	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	348	-	352	400	-	-	175	249	176	-	-	-	-	-	-	-	-	1,540	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12

Case # 22

PVRR: $49,983

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	21	21	20	21	21	21	21	21	293	499
DSM, Class 2, YA	6	7	6	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	139
DSM, Class 2 Total	37	39	40	40	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	392	705
FOT COB Flat	-	-	-	-	-	-	-	-	-	-	-	-	285	338	338	338	-	-	-	-	-	65
FOT COB Q3	-	-	122	389	389	389	289	239	400	7	110	158	-	-	-	-	-	-	-	-	223	125
FOT Mid Columbia Flat	-	-	-	143	123	128	121	318	134	172	201	205	59	62	80	6	108	123	159	174	114	116
FOT West Main Q3	-	-	-	43	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	29	15
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	-	-	5	7	N/A	10
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	154	157	151	141	123	114	84	75	N/A	125
Annual Additions, Long Term Resources	271	833	695	1,516	767	918	907	913	883	1,479	852	802	105	106	108	117	2,585	107	104	106		
Annual Additions, Short Term Resources	-	-	122	591	605	700	653	807	1,007	658	791	843	978	1,081	1,208	1,258	284	433	763	818		
Total Annual Additions	271	833	817	2,108	1,372	1,618	1,560	1,720	1,890	2,137	1,644	1,645	1,083	1,187	1,316	1,375	2,868	540	867	924		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 23

PVRR: $51,692

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	-	113	-	187	-	-	-	-	-	-	-	-	113	300
	Wind, GO, 29	-	-	44	256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	109	91	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	436	64	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	-	-	-	-	-	88
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	47	750	15	-	-	-	-	-	-	-	-	47	812
	Wind, WYSW, 29	-	-	-	-	-	-	750	50	-	-	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	309	56	244	201	491	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	408	300	500	500	491	750	486	173	750	750	291	-	-	-	-	-	-	-	-	4,457	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	47	55	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	524	1,128
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	62	64	64	64	63	65	68	67	67	68	70	71	86	77	76	73	73	617	1,346
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	480	480	480	480	-	96
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	159	-	64	277	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	-	-	259	-	264	577	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	8	7	7	7	9	63	136
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	31	31	31	30	31	32	31	31	31	32	388	699
	FOT COB Flat	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	1	0
	FOT COB Q3	-	-	-	191	114	124	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43	21
	FOT Mid Columbia Flat	-	-	-	-	86	85	79	67	55	83	112	109	-	-	-	-	-	-	-	-	46	34
	FOT MidColumbia Q3	-	-	-	114	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	6
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	107	102	102	76	78	73	72	68	N/A	85
	Annual Additions, Long Term Resources	267	638	689	1,523	767	913	900	907	876	870	851	390	101	102	103	119	4,184	107	104	105		
	Annual Additions, Short Term Resources	-	-	-	305	201	209	79	67	55	90	112	109	107	102	102	76	558	553	552	548		
	Total Annual Additions	267	638	689	1,828	967	1,122	979	974	931	959	962	500	208	204	206	195	4,743	660	656	653		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 24

PVRR: $60,693

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	135	165	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	206	94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	154	46	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	161	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	424	-	-	-	-	-	-	-	-	-	-	-	-	424	424
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	-	111	-	-	-	-	-	-	-	-	-	111
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	39	750	-	-	-	-	-	-	-	-	-	39	789
	Wind, WYSW, 29	-	-	-	-	-	59	750	67	-	-	-	-	-	-	-	-	-	-	-	-	876	876
	Wind, WYSW, 35	-	327	55	406	201	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	588	300	500	500	370	750	491	289	750	750	111	-	-	-	-	-	-	-	-	4,637	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	46
	DSM, Class 2, UT	47	55	49	52	53	53	53	52	53	57	60	60	61	63	65	73	65	62	60	60	524	1,153
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	177
	DSM, Class 2 Total	51	61	58	63	64	64	64	63	65	69	71	72	74	75	77	86	77	76	73	73	621	1,375
	FOT Mona Q3	-	-	-	59	90	180	200	200	27	200	200	200	200	200	200	109	-	-	-	-	96	103
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	551	600	600	600	600	600	480	480	480	480	480	103	322
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	31	-	10	34	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	280	-	59	161	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	-	-	380	-	259	461	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	33	66
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	499
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	8	7	7	7	9	63	136
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	31	31	31	31	31	32	31	31	31	33	388	701

Case # 24

PVRR: $60,693

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
FOT COB Flat	-	-	128	-	-	-	289	239	239	239	338	338	338	338	-	-	-	-	-	-	114	124
FOT COB Q3	-	-	-	389	389	389	-	-	-	-	-	-	-	-	338	338	-	-	-	-	117	92
FOT Mid Columbia Flat	-	-	-	-	128	137	140	352	136	178	214	223	146	102	66	28	85	202	265	273	107	134
FOT MidColumbia Q3	-	-	-	147	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7
FOT West Main Q3	-	-	-	-	-	-	43	50	-	50	4	50	50	50	50	50	-	-	-	-	14	20
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	5	10	-	24	-	-	-	-	N/A	5
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	125	297	578	-	-	-	-	N/A	125
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	206	205	193	181	163	52	-	-	N/A	125
Annual Additions, Long Term Resources	268	819	689	1,523	767	913	900	908	876	877	854	215	106	107	110	119	4,185	107	104	106		
Annual Additions, Short Term Resources	-	-	128	596	607	706	673	841	883	1,218	1,355	1,411	1,544	1,646	1,771	1,820	728	745	780	835		
Total Annual Additions	268	819	818	2,119	1,374	1,620	1,573	1,749	1,759	2,095	2,210	1,626	1,651	1,753	1,881	1,939	4,913	852	884	941		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 25

PVRR: $58,838

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	251	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	12	-	238	50	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	30	470	-	-	-	-	-	-	-	-	-	30	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	20	53	175	-	-	-	-	-	-	-	-	20	248
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	228	-	-	-	-	-	-	-	-	-	-	228
	Wind, WYSW, 29	-	-	-	-	-	-	701	100	-	-	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	-	399	389	201	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	399	401	500	750	750	600	49	501	750	175	-	-	-	-	-	-	-	-	4,148	5,073
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	43	55	49	51	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	519	1,123
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	46	61	57	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	73	615	1,344
	FOT Mona Q3	-	-	-	-	-	-	-	165	200	200	200	200	200	-	200	82	200	-	200	-	57	92
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	480	480	480	480	480	480	480	480	480	189	96	273
	FOT Utah Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	16	-	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	242	234	N/A	70
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	966	N/A	125
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	51	49	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	51	450	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	1	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	101	99	-	-	-	151	701	249	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	61	129
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	31	31	385	691

Case # 25

PVRR: $58,838

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
FOT COB Flat	-	-	185	389	-	-	-	-	-	-	-	-	-	-	-	-	338	338	338	338	57	96
FOT COB Q3	-	-	-	-	400	400	400	400	400	400	400	400	400	338	400	338	-	-	-	-	240	234
FOT MidColumbia Q3	-	-	-	272	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	267	334
FOT West Main Q3	-	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	25	38
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	86	85	103	79	335	325	321	318	N/A	206
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	10	22	120	389	398	567	459	36	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	278	82	-	103	283	31	223	N/A	125
Annual Additions, Long Term Resources	262	329	689	1,522	767	913	900	908	883	869	849	274	101	102	103	118	984	106	104	104		
Annual Additions, Short Term Resources	-	-	185	661	800	850	850	1,015	1,530	1,530	1,530	1,530	1,626	1,669	1,862	1,849	2,304	2,453	2,604	2,769		
Total Annual Additions	262	329	874	2,184	1,567	1,763	1,750	1,923	2,413	2,400	2,379	1,804	1,726	1,771	1,965	1,967	3,288	2,560	2,708	2,873		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 26

PVRR: $59,660

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	48	252	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	11	-	240	50	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	-	95	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	51	450	-	-	-	-	-	-	-	-	-	51	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	441	-	-	-	-	-	-	-	-	-	-	-	-	441	441
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	116
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	301	484	-	-	-	-	-	-	-	-	-	784
	Wind, WYSW, 29	-	-	-	-	-	-	701	158	-	-	-	-	-	-	-	-	-	-	-	-	859	859
	Wind, WYSW, 35	-	-	359	335	201	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	359	441	500	750	750	600	48	503	750	600	-	-	-	-	-	-	-	-	4,148	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	47	55	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	523	1,127
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	73	620	1,348
	FOT Mona Q3	-	-	-	-	-	-	-	200	-	51	143	200	-	-	-	124	-	-	-	-	25	36
	FOT Mead Q3	-	-	-	-	-	-	-	-	272	480	480	482	326	357	480	480	480	-	-	-	75	192
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	51	50	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	-	453	47	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	41	59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	141	59	-	-	-	151	702	247	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	62	131
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	31	31	387	693
	FOT COB Flat	-	-	182	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	29
	FOT COB Q3	-	-	-	-	400	400	400	400	400	400	400	400	338	338	237	338	-	-	-	-	240	222
	FOT MidColumbia Q3	-	-	-	254	400	328	400	400	400	400	400	400	400	400	400	400	251	257	268	277	258	302
	FOT West Main Q3	-	-	-	-	-	-	-	9	-	50	-	-	-	-	-	-	-	-	-	-	6	3
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	35	85	92	73	-	-	-	-	N/A	36
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	175	179	265	381	-	-	-	-	N/A	125
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	403	289	292	16	-	-	-	-	N/A	125
	Annual Additions, Long Term Resources	267	330	689	1,523	767	913	900	908	883	869	849	698	101	102	103	118	4,184	106	104	104		
	Annual Additions, Short Term Resources	-	-	182	643	800	728	800	1,009	1,072	1,381	1,423	1,482	1,676	1,664	1,794	1,843	731	268	303	360		
	Total Annual Additions	267	330	870	2,167	1,567	1,641	1,700	1,916	1,956	2,251	2,273	2,180	1,776	1,765	1,897	1,961	4,915	375	407	463		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 27

PVRR: $60,484

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	130	170	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	201	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	171	29	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	48	183	-	-	-	-	-	-	-	-	-	-	-	231	231
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	750	100	-	-	-	-	-	-	-	-	51	900
	Wind, WYSW, 29	-	-	-	-	-	-	750	319	-	-	-	-	-	-	-	-	-	-	-	-	1,069	1,069
	Wind, WYSW, 35	-	323	76	368	201	333	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	422	477	467	500	333	750	367	483	750	750	100	-	-	-	-	-	-	-	-	4,648	5,497
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	-	-	-	-	-	11	19
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	0	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	47	59	49	52	53	58	60	57	60	61	60	60	62	63	65	73	65	62	57	55	557	1,178
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	10	10	10	10	10	11	10	10	10	11	11	10	76	179
	DSM, Class 2 Total	51	65	58	63	64	69	71	69	73	74	72	72	74	76	77	86	77	75	70	67	655	1,403
	FOT Mona Q3	-	-	-	-	-	-	-	137	-	22	60	112	-	-	36	147	-	200	200	-	16	46
	FOT Mead Q3	-	-	-	-	-	-	-	-	169	480	480	480	480	344	480	480	480	480	480	-	65	242
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	27	31	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	317	-	183	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	77	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	81	-	-	-	-	-	-	-	-	-	81
	Wind, WW, 29 PPA	-	-	-	33	-	100	-	100	67	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	197	23	33	-	417	-	383	267	-	-	81	-	-	-	-	-	-	-	-	1,365	1,446
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	34	65
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	20	21	21	21	21	20	293	500
	DSM, Class 2, YA	6	7	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	6	6	63	130
	DSM, Class 2 Total	37	39	40	40	40	41	41	41	41	31	31	31	31	30	31	31	30	30	30	29	390	695
	FOT COB Flat	-	-	126	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	6
	FOT COB Q3	-	-	-	389	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	279	339
	FOT MidColumbia Q3	-	-	-	204	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	117	260	316
	FOT West Main Q3	-	-	-	-	-	-	-	50	50	50	50	50	50	50	50	50	-	-	-	-	15	23
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	201	178	117	87	-	368	397	653	N/A	250
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	431	-	1,569	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	44	288	291	256	-	121	-	-	N/A	125
	Annual Additions, Long Term Resources	267	834	689	1,523	767	919	908	913	885	882	856	286	107	108	109	117	4,184	106	99	97		
	Annual Additions, Short Term Resources	-	-	126	593	800	800	800	987	1,019	1,352	1,390	1,443	1,575	1,676	1,802	1,852	1,280	2,410	1,911	2,821		
	Total Annual Additions	267	834	816	2,116	1,567	1,719	1,708	1,900	1,904	2,235	2,246	1,728	1,683	1,785	1,911	1,969	5,464	2,516	2,011	2,917		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 28

PVRR: $47,806

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	-	251	50	-	-	-	-	-	-	-	-	-	251	300
	Wind, GO, 29	-	-	249	51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	668	203	429	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	307	45	213	201	535	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	406	493	264	500	535	668	203	429	451	50	-	-	-	-	-	-	-	-	-	4,048	4,098
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	20	42
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	56	58	59	73	59	55	57	55	530	1,113
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	68	67	67	68	70	71	85	72	68	70	68	625	1,331
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	201	100	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	18	82	100	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	136	-	97	-	247	20	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	93	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	213	7	236	-	215	82	547	321	300	-	-	-	-	-	-	-	-	-	-	1,965	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	20	20	21	21	21	293	498
	DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	140
	DSM, Class 2 Total	37	39	41	41	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	393	705
	FOT COB Q3	-	-	-	192	116	400	400	400	400	4	-	-	-	-	-	-	-	400	-	-	191	116
	FOT Mid Columbia Flat	-	-	-	109	81	79	70	53	45	66	94	92	-	-	-	-	-	-	-	-	50	35
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	89	84	85	58	60	55	54	49	N/A	67
	Annual Additions, Long Term Resources	271	833	695	1,516	766	912	898	906	874	867	148	98	100	101	102	117	4,179	99	101	101		
	Annual Additions, Short Term Resources	-	-	-	302	197	479	470	453	445	70	94	92	89	84	85	58	60	455	54	49		
	Total Annual Additions	271	833	695	1,818	963	1,392	1,368	1,359	1,319	937	242	190	188	185	187	175	4,239	555	155	150		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 29

PVRR: $57,635

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	101	200	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	218	82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	-	207	-	-	-	-	-	-	-	-	-	-	207
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	493	700	-	-	-	-	-	-	-	-	-	1,193
	Wind, WYSW, 29	-	-	-	-	-	-	750	223	327	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	322	60	229	201	489	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	421	478	311	500	489	750	223	628	200	701	700	-	-	-	-	-	-	-	-	4,098	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	-	-	-	-	-	10	19
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	8	8	8	8	8	8	8	8	8	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	92	12	-	-	-	-	-	-	-	-	-	-	290	290
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	46
	DSM, Class 2, UT	50	64	56	57	58	58	60	57	60	61	60	60	62	63	65	89	65	68	68	61	583	1,244
	DSM, Class 2, WY	1	4	6	9	9	10	10	9	10	10	10	10	10	11	11	11	10	11	11	10	78	183
	DSM, Class 2 Total	54	70	65	68	70	70	72	69	73	74	72	72	74	76	78	102	78	81	81	74	684	1,474
	FOT Mona Q3	-	-	-	-	-	-	-	26	-	200	200	200	-	-	-	-	-	-	-	-	23	31
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	69	106	160	-	-	-	-	-	-	-	-	7	17
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	50	50	-	-	-	-	-	-	-	-	10	10
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	27	31	-	10	34	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	-	78	22	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	89	-	161	-	250	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	78	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	151	50	-	-	-	-	-	-	-	-	-	151	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	198	22	189	-	261	-	527	122	551	50	-	-	-	-	-	-	-	-	-	1,916	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	1	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	-	1	3	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	22	3	-	-	-	-	-	-	-	-	-	-	26	26

Case # 29

PVRR: $57,635

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	21	21	21	21	21	21	294	502
DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	67	140
DSM, Class 2 Total	37	39	41	41	41	41	41	42	41	31	31	31	31	31	31	32	31	31	31	33	395	709
FOT COB Flat	-	-	-	-	-	-	-	-	-	-	-	-	338	338	338	338	-	-	-	-	-	68
FOT COB Q3	-	-	102	389	389	400	400	400	400	239	338	338	-	-	-	-	-	400	-	-	272	190
FOT Mid Columbia Flat	-	-	-	142	124	211	266	400	400	400	400	400	328	348	358	326	81	101	125	141	194	228
FOT MidColumbia Q3	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	1
FOT West Main Q3	-	-	-	25	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	32	31
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	170	172	181	202	-	-	-	-	N/A	91
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	107	186	287	334	-	-	-	-	N/A	114
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	324	321	315	311	140	127	114	105	N/A	220
Annual Additions, Long Term Resources	272	845	708	1,529	778	925	914	920	995	886	855	805	108	109	111	135	4,652	112	112	107		
Annual Additions, Short Term Resources	-	-	102	556	564	661	716	926	850	1,009	1,144	1,197	1,330	1,431	1,555	1,591	221	638	273	328		
Total Annual Additions	272	845	811	2,085	1,342	1,586	1,630	1,845	1,845	1,895	1,999	2,002	1,438	1,539	1,666	1,726	4,873	750	384	435		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 30

PVRR: $48,541

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	251	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	-	150	50	-	-	-	-	-	-	-	-	-	200
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	-	-	47	453	-	-	-	-	-	-	-	-	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	360	-	-	-	-	-	-	-	-	-	-	360	360
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	-	408	142	350	-	-	-	-	-	-	-	900
	Wind, WYSW, 29	-	-	-	-	-	-	-	400	501	39	-	-	-	-	-	-	-	-	-	-	940	940
	Wind, WYSW, 35	-	-	-	150	300	411	440	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	150	300	750	750	550	550	650	150	506	594	350	-	-	-	-	-	-	3,898	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	47	55	49	49	52	53	53	52	53	57	55	60	61	63	65	89	65	62	68	61	520	1,170
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	59	64	64	64	63	65	69	67	72	74	75	77	102	77	76	81	74	616	1,391
	FOT Mona Q3	-	-	-	90	196	200	200	200	59	200	200	200	200	200	200	200	-	-	-	-	115	117
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	599	480	-	-	-	108	258
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	1	3	-	-	-	-	6	N/A	1
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100
	Wind, MC, 29	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	144	156	-	-	-	-	-	-	-	-	300
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	200	300
	Total Wind	45	20	-	-	200	-	-	200	200	100	600	244	156	-	-	-	-	-	-	-	765	1,765
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	33	66
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	21	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	8	7	7	7	9	63	136
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	41	30	31	31	31	31	31	32	31	31	31	33	387	700
	FOT COB Flat	-	-	197	-	389	389	289	239	239	239	338	338	338	338	338	338	-	-	-	-	198	200
	FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39	19
	FOT Mid Columbia Flat	-	-	-	-	128	152	199	373	144	217	236	277	181	149	138	55	70	70	86	88	121	128
	FOT MidColumbia Q3	-	-	-	152	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	FOT West Main Q3	-	-	-	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	25	13
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	152	149	147	131	119	114	98	91	N/A	125
	Annual Additions, Long Term Resources	267	329	188	1,157	704	954	900	943	883	870	851	855	857	458	110	135	4,651	107	112	107		
	Annual Additions, Short Term Resources	-	-	197	681	764	791	738	863	922	1,256	1,373	1,414	1,471	1,437	1,425	1,322	669	184	183	185		
	Total Annual Additions	267	329	385	1,839	1,467	1,746	1,639	1,805	1,805	2,126	2,224	2,270	2,328	1,895	1,535	1,457	5,319	291	295	292		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 31

PVRR: $47,552

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	215	85	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	227	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	61	-	139	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	33	200	-	-	-	-	-	-	-	-	-	-	232	232
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	750	100	-	-	-	-	-	-	-	-	51	900
	Wind, WYSW, 29	-	-	-	-	-	-	39	396	632	-	-	-	-	-	-	-	-	-	-	-	1,068	1,068
	Wind, WYSW, 35	-	320	53	54	182	280	411	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	419	480	127	182	341	750	750	750	750	750	100	-	-	-	-	-	-	-	-	4,648	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	46
	DSM, Class 2, UT	50	59	56	57	58	58	60	57	60	61	60	60	62	63	65	89	65	62	60	60	577	1,225
	DSM, Class 2, WY	1	4	6	9	9	9	10	9	10	10	10	10	10	11	11	11	10	11	11	10	77	182
	DSM, Class 2 Total	54	65	65	68	69	70	72	69	73	74	72	72	74	76	78	102	78	76	73	72	677	1,452
	FOT Mona Q3	-	-	-	42	35	165	200	200	-	200	200	200	200	200	200	200	200	200	200	-	84	132
	FOT Mead Q3	-	-	-	-	-	-	-	-	451	508	560	600	600	600	600	543	480	480	480	-	96	295
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	-	-	-	-	6	N/A	1
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100
	Wind, MC, 29	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	300
	Wind, YA, 29 PPA	-	-	-	5	95	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	168	123	209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	80	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	200	20	373	318	409	-	-	-	-	-	600	-	-	-	-	-	-	-	-	1,365	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	21	21	21	21	21	21	294	501
	DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	7	67	139
	DSM, Class 2 Total	37	39	41	41	41	41	41	42	41	31	31	31	31	31	31	32	31	31	31	31	395	707
	FOT COB Flat	-	-	115	-	-	-	289	-	-	-	-	-	338	338	338	338	-	-	-	-	40	88
	FOT COB Q3	-	-	-	389	389	389	-	239	239	239	338	338	-	-	-	-	400	400	400	-	189	188
	FOT Mid Columbia Flat	-	-	-	138	111	117	120	273	133	175	211	204	61	49	50	28	56	57	73	120	107	99
	FOT West Main Q3	-	-	-	-	50	-	17	50	-	50	-	6	50	34	-	-	-	-	-	-	17	13
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	N/A	2
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	-	-	N/A	2
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	160	153	154	150	124	118	102	39	N/A	125
	Annual Additions, Long Term Resources	272	835	709	1,516	773	919	909	914	885	882	855	805	108	109	111	136	4,185	107	104	103		
	Annual Additions, Short Term Resources	-	-	115	570	586	671	626	762	824	1,172	1,308	1,348	1,409	1,375	1,362	1,258	1,261	1,256	1,255	178		
	Total Annual Additions	272	835	824	2,086	1,359	1,590	1,535	1,677	1,709	2,055	2,164	2,153	1,517	1,484	1,473	1,394	5,446	1,363	1,359	281		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 33

PVRR: $69,949

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	SCCT Frame ID	-	-	-	-	-	-	-	302	-	-	-	-	-	-	-	-	-	-	-	-	302	302
	SCCT Frame WYNE	-	-	-	-	-	-	-	275	-	-	-	-	-	-	-	-	-	-	-	-	275	275
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	83	-	-	-	-	17	150	50	-	-	-	-	-	-	-	-	-	251	300
	Wind, GO, 29	-	-	172	128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	182	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	519	131	750	-	-	-	-	-	-	-	-	1,400
	Wind, WYSW, 29	-	-	-	-	-	-	550	217	533	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	314	124	171	201	491	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	413	478	400	500	491	550	217	750	150	569	131	750	-	-	-	-	-	-	-	4,048	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	8	4	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	9	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	23	16	-	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, WY-Curtail	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	54	10	33	55	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	21	47
	DSM, Class 2, UT	54	64	57	57	62	63	65	61	64	66	68	66	67	69	70	90	78	74	73	63	614	1,331
	DSM, Class 2, WY	2	4	7	9	9	10	10	10	10	10	10	10	11	11	11	11	12	12	12	11	82	194
	DSM, Class 2 Total	58	70	66	68	74	75	78	73	77	79	81	78	80	82	84	104	92	88	88	77	717	1,571
	Solar	-	-	-	-	250	250	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	FOT Mona Q3	-	-	-	-	-	-	84	-	-	-	-	-	-	-	-	-	-	-	-	-	8	4
	FOT Mead Q3	-	-	-	-	-	-	-	-	114	75	254	-	-	-	-	-	-	-	-	-	19	22
	FOT Utah Q3	-	18	-	50	-	-	50	-	50	50	50	49	50	50	50	50	50	50	50	50	22	36
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	220	279	243	259	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	252	144	267	337	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	155	362	452	N/A	125
West																							
	CCCT H 2x1	-	-	-	-	-	-	-	-	-	-	-	523	-	-	-	-	-	-	-	-	-	523
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	8	-	-	92	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	67	-	433	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	86	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	206	22	100	-	259	200	533	-	600	-	-	-	-	-	-	-	-	-	-	1,965	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	385	-	-	790
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	3	1	-	-	-	-	-	-	-	-	-	-	25	25

Case # 33

PVRR: $69,949

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, WW-Irrigate	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, WM-Irrigate	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, YA-Curtail	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, YA-Irrigate	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1 & 3 Total	-	-	-	20	-	-	8	-	6	-	-	-	-	-	-	-	-	-	-	-	34	34
DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	4	3	4	4	4	4	4	4	34	70
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	21	21	21	21	21	21	294	504
DSM, Class 2, YA	7	7	7	6	6	7	7	7	7	8	8	8	8	8	8	9	8	8	8	9	68	149
DSM, Class 2 Total	38	39	41	41	41	41	41	42	41	31	32	32	32	32	32	34	32	33	33	34	396	722
FOT COB Flat	-	-	371	-	-	-	-	-	-	-	-	338	338	338	338	338	338	338	338	-	37	154
FOT COB Q3	-	-	-	389	400	400	400	400	400	239	338	-	-	-	-	-	-	-	-	338	263	165
FOT Mid Columbia Flat	-	-	-	400	396	400	400	383	400	400	400	400	400	400	400	400	400	400	400	400	278	339
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	27	218	303	453	367	275	180	178	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	267	489	294	203	253	495	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	272	358	314	164	281	374	133	104	N/A	250
Annual Additions, Long Term Resources	282	845	709	1,573	1,033	1,203	973	1,501	900	1,481	683	765	864	116	118	139	124	526	506	111		
Annual Additions, Short Term Resources	-	18	371	889	846	850	984	833	1,014	814	1,092	837	1,136	1,414	1,720	1,943	2,283	2,267	2,275	2,662		
Total Annual Additions	282	863	1,080	2,462	1,879	2,053	1,957	2,334	1,914	2,295	1,775	1,602	2,000	1,531	1,838	2,082	2,407	2,792	2,781	2,773		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 34

PVRR: $40,564

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	53	247	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	14	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	180	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	80	503	716	-	-	-	-	-	-	-	-	-	584	1,300
	Wind, WYSW, 35	-	-	353	78	327	304	239	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	353	258	500	750	239	-	134	750	716	-	-	-	-	-	-	-	-	-	3,181	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	7	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	17	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	45	51	51	50	52	51	55	54	54	56	58	62	59	55	57	56	480	1,045
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	70	171
	DSM, Class 2 Total	45	54	52	55	56	61	62	61	64	63	66	65	66	68	70	74	72	68	70	68	572	1,259
	FOT Mona Q3	-	-	-	79	158	200	200	200	87	200	200	200	200	200	200	200	200	200	200	200	112	156
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	47	-	-	-	-	5	5
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	94	163	-	11	35	83	N/A	50
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	2	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	20	20
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	495
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	56	122
	DSM, Class 2 Total	36	37	39	39	39	39	39	40	40	30	30	30	30	29	30	31	30	30	30	30	377	678
	FOT COB Flat	-	-	200	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	238	271
	FOT COB Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	-	17
	FOT Mid Columbia Flat	-	-	-	-	130	163	233	400	163	271	306	366	321	400	400	400	400	400	400	400	136	258
	FOT MidColumbia Q3	-	-	-	149	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7
	FOT West Main Q3	-	-	-	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	34	42
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	100	105	107	111	118	129	144	N/A	114
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	195	376	646	780	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	90	97	144	85	261	218	67	39	N/A	125
	Annual Additions, Long Term Resources	262	321	538	1,471	692	914	396	167	258	863	815	97	98	100	102	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	-	200	653	728	803	772	939	1,019	1,360	1,493	1,554	1,694	1,801	1,932	1,990	2,155	2,311	2,465	2,634		
	Total Annual Additions	262	321	738	2,124	1,420	1,717	1,168	1,106	1,277	2,223	2,309	1,651	1,792	1,901	2,034	2,097	2,257	2,409	2,565	2,732		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 35

PVRR: $39,853

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	101	-	200	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	226	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	170	-	-	-	-	-	-	-	-	-	-	170	170
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	548	326	256	-	-	-	-	-	-	-	-	-	-	1,130	1,130
	Wind, WYSW, 35	-	321	53	51	167	257	451	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	420	479	125	167	358	750	748	326	426	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	55	56	58	59	73	59	55	57	55	530	1,113
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	69	67	67	68	70	71	85	72	68	70	67	627	1,331
	FOT Mona Q3	-	-	-	53	134	200	200	200	78	-	-	-	-	132	200	200	200	200	200	-	87	100
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	333	343	396	480	480	508	531	600	600	480	-	81	262
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	75	133	292	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	79	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	199	21	375	333	392	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	20	293	498
	DSM, Class 2, YA	6	7	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	6	63	130
	DSM, Class 2 Total	37	39	40	40	40	41	40	40	40	30	30	30	31	30	31	31	30	30	30	30	389	691
	FOT COB Flat	-	-	122	-	-	389	289	239	239	239	338	-	338	338	338	338	338	338	-	-	152	194
	FOT COB Q3	-	-	-	389	389	-	-	-	-	-	-	338	-	-	-	-	-	-	338	400	78	93
	FOT Mid Columbia Flat	-	-	-	136	109	118	151	362	136	178	214	223	8	20	46	26	105	109	115	117	119	109
	FOT West Main Q3	-	-	-	-	-	19	50	50	-	-	-	-	47	-	12	50	50	50	50	50	12	21
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	5	9	-	7	54	168	285	472	N/A	125
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	232	359	1,000	N/A	203
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	218	208	203	202	168	-	-	-	N/A	125
	Annual Additions, Long Term Resources	271	834	701	1,510	731	912	898	902	450	1,149	97	97	99	100	101	116	102	98	100	97		
	Annual Additions, Short Term Resources	-	-	122	578	632	726	690	851	933	750	895	956	1,096	1,203	1,335	1,386	1,551	1,707	1,861	2,122		
	Total Annual Additions	271	834	823	2,088	1,362	1,638	1,587	1,754	1,383	1,900	992	1,053	1,194	1,303	1,436	1,502	1,653	1,805	1,961	2,219		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 36

PVRR: $51,242

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	-	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	251	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	76	-	-	-	-	-	-	-	-	-	-	76	76
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	201	650	373	-	-	-	-	-	-	-	-	-	-	-	1,224	1,224
	Wind, WYSW, 35	-	-	-	418	201	632	50	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	418	500	632	750	650	423	327	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	8	8	8	8	4	8	8	8	4	4	-	-	-	-	-	-	-	-	64	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	7
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	2
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	78	-	-	-	-	-	-	-	-	212	290
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	47	55	49	50	52	53	53	52	53	57	60	60	56	58	59	73	65	62	60	60	521	1,134
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	60	64	64	64	63	65	69	71	72	68	70	71	86	77	76	73	73	617	1,354
	FOT Mona Q3	-	-	-	-	130	200	-	200	-	143	200	200	200	200	200	200	200	200	200	200	67	134
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	600	600	480	600	600	600	600	600	600	600	96	342
	FOT Utah Q3	-	-	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	63	83	N/A	29
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 35	-	-	-	82	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	82	-	118	-	100	200	-	-	-	-	-	-	-	-	-	-	-	565	565
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	3	3	3	3	1	3	3	3	2	2	-	-	-	-	-	-	-	-	22	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	26
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	61	130
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	31	31	385	691

Case # 36

PVRR: $51,242

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
FOT COB Flat	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	400	-	-	-	-	120	180
FOT COB Q3	-	-	192	389	389	389	289	-	-	-	-	-	-	-	-	-	338	338	338	338	165	150
FOT Mid Columbia Flat	-	-	-	-	-	-	363	400	400	400	400	400	400	400	400	400	400	-	-	-	156	218
FOT MidColumbia Q3	-	-	-	226	133	151	-	-	-	-	-	-	-	-	-	-	-	203	268	329	51	66
FOT West Main Q3	-	-	-	50	50	50	50	50	-	-	-	50	50	50	50	50	50	50	50	50	25	35
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	94	98	172	106	278	396	360	362	N/A	233
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	40	440	222	147	279	367	504	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	214	282	372	132	209	294	276	222	N/A	250
Annual Additions, Long Term Resources	266	328	194	1,526	738	919	900	913	760	451	109	1,089	101	102	103	118	108	106	104	104		
Annual Additions, Short Term Resources	-	-	192	665	703	790	702	1,050	1,280	1,423	1,600	1,700	1,838	2,088	2,661	2,142	2,221	2,371	2,522	2,687		
Total Annual Additions	266	328	386	2,191	1,440	1,709	1,602	1,963	2,040	1,874	1,709	2,789	1,939	2,189	2,764	2,260	2,329	2,477	2,626	2,790		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 37

PVRR: $48,949

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	-	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	-	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	238	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	123	77	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	179	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	101	627	373	200	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	321	42	91	361	238	249	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	153	500	398	349	750	750	200	-	-	-	-	-	-	-	-	-	-	4,097	4,097
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	530	1,134
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	73	628	1,356
	FOT Mona Q3	-	-	-	16	75	169	200	200	-	200	200	-	-	-	-	-	-	-	-	-	86	53
	FOT Mead Q3	-	-	-	-	-	-	-	-	479	594	600	-	-	-	-	-	-	-	480	480	107	132
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	288	12	-	-	-	-	-	-	-	-	-	288	300
	Wind, YA, 29 PPA	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	247	-	152	101	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	163	-	-	-	-	-	-	-	-	-	-	163	163
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	347	-	352	401	-	-	551	12	-	-	-	-	-	-	-	-	-	1,916	1,928
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
	DSM, Class 2, YA	6	7	6	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	139
	DSM, Class 2 Total	37	39	40	40	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	392	705
	FOT COB Q3	-	-	122	389	389	389	289	239	400	239	338	-	-	-	-	-	-	-	-	-	246	140
	FOT Mid Columbia Flat	-	-	-	143	123	128	158	367	134	162	201	206	60	63	81	76	109	124	165	182	122	124
	FOT West Main Q3	-	-	-	44	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	34	20
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	154	157	151	141	123	114	84	75	N/A	125
	Annual Additions, Long Term Resources	271	833	694	1,516	731	913	898	906	874	874	110	4,174	100	101	102	117	109	107	104	106		
	Annual Additions, Short Term Resources	-	-	122	592	637	736	697	856	1,064	1,245	1,388	206	214	236	260	249	232	249	764	819		
	Total Annual Additions	271	833	817	2,108	1,369	1,649	1,595	1,762	1,938	2,119	1,499	4,380	314	337	362	367	341	356	868	925		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 38

PVRR: $41,974

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	48	171	-	-	-	-	-	-	-	-	-	-	219	219
	Wind, GO, 29	-	-	-	-	-	-	-	190	110	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	208	-	-	-	-	579	513	-	-	-	-	-	-	-	-	-	787	1,300
	Total Wind	99	99	-	-	208	-	300	190	157	750	513	-	-	-	-	-	-	-	-	-	1,803	2,316
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	53	10	10	-	-	-	-	-	-	-	-	-	-	249	249
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	43	49	49	48	49	51	51	50	53	51	55	54	54	56	58	62	59	62	60	60	493	1,073
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	73	173
	DSM, Class 2 Total	46	54	57	59	60	62	62	61	64	63	67	65	66	68	70	74	72	75	73	72	589	1,290
	FOT Mona Q3	-	-	-	-	-	34	102	200	-	176	200	200	200	200	200	200	200	200	200	200	51	126
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	496	557	580	600	600	600	518	600	600	600	96	336
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	23	34	38	-	17	42	89	N/A	30
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	-	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	20	20
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	62
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	291	496
	DSM, Class 2, YA	5	6	6	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	58	123
	DSM, Class 2 Total	36	37	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	379	680
	FOT COB Flat	-	-	193	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	237	287
	FOT MidColumbia Q3	-	-	-	288	326	400	400	400	241	400	400	400	400	400	400	400	400	400	400	400	245	323
	FOT West Main Q3	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	30	40
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	116	121	128	131	122	121	151	147	N/A	130
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	224	518	303	359	479	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	60	56	-	-	266	308	310	N/A	125
	Annual Additions, Long Term Resources	267	327	191	1,011	407	166	453	414	282	863	612	97	98	100	101	107	102	106	103	103		
	Annual Additions, Short Term Resources	-	-	193	678	765	873	841	939	1,010	1,346	1,483	1,544	1,684	1,791	1,922	1,981	2,145	2,296	2,447	2,613		
	Total Annual Additions	267	327	385	1,689	1,172	1,039	1,294	1,353	1,292	2,209	2,095	1,641	1,782	1,891	2,024	2,087	2,247	2,401	2,551	2,715		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 39

PVRR: $34,791

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	48	252	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	298	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	182	-	-	-	-	-	-	-	-	18	-	-	-	-	-	-	182	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55	-	55
	Wind, WYSW, 35	-	178	224	16	178	114	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	277	224	315	362	253	750	-	48	252	-	-	-	18	-	-	-	-	-	55	2,580	2,653
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	2	-	6
	CHP - Kern River	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	8	4	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	93	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	61	63	65	89	66	68	68	62	530	1,182
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	11	11	11	11	75	178
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	69	67	67	73	75	77	102	79	82	81	75	627	1,405
	FOT Mona Q3	-	-	-	-	-	-	-	-	77	-	-	-	-	-	-	-	-	-	-	-	8	4
	FOT Utah Q3	-	-	-	-	-	-	-	50	50	-	-	43	-	-	-	-	-	-	-	-	10	7
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	194	N/A	39
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	N/A	14
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	76	85	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	120	276	185	138	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	865	865
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	1
	Distributed Standby Generation	3	3	3	3	3	3	3	3	3	1	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	500
	DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	67	140
	DSM, Class 2 Total	37	39	41	41	41	41	41	41	41	30	31	31	31	31	31	32	31	32	31	33	393	707
	FOT COB Flat	-	-	156	-	389	389	289	239	239	226	338	338	338	338	338	338	338	-	-	-	193	215
	FOT COB Q3	-	-	-	196	-	-	-	-	-	-	-	-	-	-	-	-	-	338	400	338	20	64
	FOT MidColumbia Q3	-	-	-	400	228	323	379	400	400	400	400	400	400	400	400	400	400	400	400	400	253	327
	FOT West Main Q3	-	-	-	-	-	-	-	50	50	-	32	50	-	33	50	50	50	50	50	50	10	26
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94	163	295	197	256	209	N/A	152
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	132	257	365	247	N/A	125
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	228	279	282	247	173	278	229	284	N/A	250
	Annual Additions, Long Term Resources	276	617	700	1,516	736	527	903	270	177	970	98	98	105	124	108	134	111	115	115	166		
	Annual Additions, Short Term Resources	-	-	156	596	617	713	668	739	817	626	770	830	965	1,066	1,192	1,229	1,387	1,530	1,735	1,831		
	Total Annual Additions	276	617	856	2,112	1,353	1,240	1,572	1,009	994	1,596	868	928	1,070	1,189	1,300	1,363	1,498	1,645	1,850	1,997		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 40

PVRR: $25,139

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	193	107	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	341	750	209	-	-	-	-	-	-	-	-	341	1,300
	Total Wind	99	99	-	-	-	-	-	193	298	750	750	209	-	-	-	-	-	-	-	-	1,439	2,398
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	-	13
	CHP - Kern River	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	8	4	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	92	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	45	46	46	45	52	51	55	53	54	56	58	62	59	62	60	60	465	1,044
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	70	170
	DSM, Class 2 Total	45	54	52	55	56	57	57	56	64	62	66	65	66	68	70	74	72	75	73	72	557	1,257
	FOT Mona Q3	-	-	-	93	200	200	200	200	-	200	200	200	200	200	200	200	200	200	200	200	109	155
	FOT Mead Q3	-	-	-	-	-	-	-	-	553	600	600	600	600	600	600	600	600	600	600	600	115	358
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	49	50	50	50	50	50	50	50	50	50	10	30
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	148	145	148	-	189	190	180	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	44	158	191	-	204	214	189	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	26	89	86	-	104	279	415	N/A	125
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	100
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	65	165
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	-	2
	Distributed Standby Generation	3	3	3	3	3	3	3	3	3	1	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	0	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	0	-	-	-	-	25	26
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	60
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	495
	DSM, Class 2, YA	5	6	5	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	53	115
	DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	29	29	29	30	29	30	30	30	30	30	30	373	670
	FOT COB Flat	-	-	199	340	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	27
	FOT COB Q3	-	-	-	49	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	183	260
	FOT MidColumbia Q3	-	-	-	155	145	259	339	400	160	207	240	298	77	198	170	132	156	400	400	400	167	207
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	116	122	107	131	123	130	123	148	N/A	125
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	143	-	-	40	817	-	-	-	N/A	125
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	-	306	277	314	N/A	125
	Annual Additions, Long Term Resources	266	325	186	1,006	192	158	145	452	424	859	845	302	107	97	102	107	714	373	206	105		
	Annual Additions, Short Term Resources	-	-	199	688	784	898	879	939	1,003	1,347	1,476	1,535	1,677	1,776	1,907	1,965	2,333	2,571	2,720	2,883		
	Total Annual Additions	266	325	385	1,694	977	1,057	1,023	1,391	1,427	2,206	2,321	1,838	1,785	1,873	2,009	2,072	3,048	2,944	2,926	2,988		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 41

PVRR: $41,542

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	134	134
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	307	166	238	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	307	300	377	750	-	-	-	-	-	-	-	-	-	-	-	-	-	1,932	1,932
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	3.8	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	34	13	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	43	49.0	44	45	49	51	51	50	53	51	55	54	54	56	58	62	59	55	57	56	484	1,049
	DSM, Class 2, WY	1	3.4	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	172
	DSM, Class 2 Total	46	54.2	52	55	59	61	61	61	63	62	66	65	66	68	70	74	72	68	70	68	575	1,261
	FOT Utah Q3	-	-	-	-	-	4	50	50	-	-	-	21	-	-	-	-	-	-	-	-	10	6
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	584	584	584	584	584	584	584	584	584	584	584	106	345
	FOT Mona/Nevada Utah Border	-	91	56	200	200	200	200	200	78	200	200	200	200	200	200	200	200	200	200	200	142	171
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	64	139	134	169	16	-	-	-	N/A	65
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	128	-	-	-	-	N/A	16
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	8.9	3.4	-	-	-	-	-	-	-	-	-	-	-	-	12.3	12.3
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	14	3	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	496
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	57	123
	DSM, Class 2 Total	36	37.2	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	379	680
	FOT COB Flat	-	-	383	-	383	383	283	233	233	233	329	329	329	329	329	329	329	329	329	-	213	254
	FOT COB Q3	-	-	-	383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	38	39
	FOT Mid Columbia Flat	-	-	-	-	304	400	400	400	177	320	360	400	389	400	400	322	400	400	400	400	200	294
	FOT MidColumbia Q3	-	-	-	298	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	15
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	99	105	175	110	117	153	218	N/A	134
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	193	427	465	862	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	20	150	-	294	224	303	10	N/A	125
	Annual Additions, Long Term Resources	267	326	187	1,323	770	548	916	425	124	113	99	97	98	99	101	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	91	440	931	937	1,037	983	933	1,018	1,387	1,523	1,584	1,712	1,821	1,952	2,010	2,175	2,331	2,485	2,725		
	Total Annual Additions	267	417	627	2,255	1,707	1,585	1,900	1,358	1,142	1,500	1,622	1,681	1,809	1,920	2,054	2,117	2,277	2,429	2,585	2,823		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 42

PVRR: $51,420

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	209	-	-	91	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	106	94	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	61	-	-	-	-	-	-	-	-	-	-	61	61
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	544	454	50	190	-	-	-	-	-	-	-	-	-	-	1,239	1,239
	Wind, WYSW, 35	-	-	344	91	201	644	20	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	344	300	500	750	750	454	50	252	-	-	-	-	-	-	-	-	-	-	3,598	3,598
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	43	55.1	49	49	49	51	51	52	53	57	55	56	56	58	59	73	65	62	60	60	508	1,112
	DSM, Class 2, WY	1	3.4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	73	175
	DSM, Class 2 Total	46	60.4	57	59	60	62	62	63	64	68	67	67	68	70	71	86	77	76	73	73	601	1,329
	FOT Utah Q3	-	-	-	-	-	-	35	35	-	-	-	-	-	-	-	-	-	-	-	-	7	3
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	584	584	584	584	584	584	584	584	584	584	584	106	345
	FOT Mona/Nevada Utah Border	-	91	54	200	200	200	200	200	107	200	200	200	200	200	200	200	200	200	200	200	145	173
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	18	-	-	138	126	N/A	38
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	N/A	27
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	497
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37.2	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	382	688
	FOT COB Flat	-	-	383	-	-	288	283	233	233	233	329	329	329	329	329	-	-	329	329	329	165	214
	FOT COB Q3	-	-	-	383	383	95	-	-	-	-	-	-	-	-	-	329	329	-	-	-	86	76
	FOT Mid Columbia Flat	-	-	-	-	299	384	400	400	181	295	334	393	400	400	400	400	400	400	400	400	196	294
	FOT MidColumbia Q3	-	-	-	280	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28	14
	FOT West Main Q3	-	-	-	50	50	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	30	40
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	80	121	127	139	228	264	364	364	N/A	211
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	519	375	655	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	38	105	208	247	172	218	60	172	N/A	153
	Annual Additions, Long Term Resources	262	327	531	1,519	762	910	898	872	176	371	100	100	101	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	91	437	913	932	1,017	968	918	1,002	1,362	1,497	1,556	1,682	1,789	1,919	1,968	2,415	2,565	2,715	2,880		
	Total Annual Additions	262	419	968	2,432	1,694	1,927	1,865	1,790	1,177	1,733	1,597	1,656	1,783	1,891	2,022	2,086	3,399	2,671	2,820	2,984		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 43

PVRR: $60,905

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	97	181	22	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	217	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	81	-	119	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	173	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	418	-	-	-	-	-	-	-	-	-	-	-	-	418	418
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	9	100	-	-	-	-	-	-	-	-	-	109
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	741	-	-	-	-	-	-	-	-	-	51	791
	Wind, WYSW, 29	-	-	-	-	-	78	750	54	-	-	-	-	-	-	-	-	-	-	-	-	882	882
	Wind, WYSW, 35	-	327	55	417	201	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	500	500	377	750	650	181	692	750	100	-	-	-	-	-	-	-	-	4,648	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	93	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	3	3	3	2	2	2	2	2	2	2	2	2	24	48
	DSM, Class 2, UT	50	59	49	52	53	58	60	57	53	57	60	60	61	63	65	73	65	62	60	60	547	1,176
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	177
	DSM, Class 2 Total	53	65	58	63	64	69	71	69	65	69	72	72	74	75	77	86	77	76	73	73	646	1,401
	FOT Mona Q3	-	50	-	200	200	200	200	200	129	200	200	200	200	200	200	161	-	-	-	-	138	127
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	584	584	584	584	584	584	480	480	480	480	480	106	319
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	34	46	49	-	28	52	100	N/A	39
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	42	-	-	100	58	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	231	-	-	269	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	-	-	373	-	100	569	58	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	-	-	-	-	-	22	22

Case # 43

PVRR: $60,905

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	4	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	3	4	33	66
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
DSM, Class 2, YA	6	7	6	6	6	6	6	7	6	7	7	7	7	7	7	8	7	7	7	9	64	138
DSM, Class 2 Total	37	39	40	40	40	41	40	42	40	30	31	31	31	31	31	32	31	31	31	33	390	703
FOT COB Flat	-	-	352	-	-	-	283	233	233	233	329	329	329	329	-	-	-	-	-	-	133	132
FOT COB Q3	-	-	-	383	383	383	-	-	-	-	-	-	-	-	329	329	-	-	-	-	115	90
FOT Mid Columbia Flat	-	-	-	-	240	299	359	400	150	243	291	358	273	236	174	51	95	211	275	283	169	197
FOT MidColumbia Q3	-	-	-	197	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	10
FOT West Main Q3	-	-	-	50	19	50	50	50	-	50	50	50	50	50	50	50	-	-	-	-	27	28
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	1	9	-	11	-	-	-	-	N/A	3
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	99	295	606	-	-	-	-	N/A	125
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	206	205	193	181	163	53	-	-	N/A	125
Annual Additions, Long Term Resources	277	840	695	1,529	772	924	913	1,024	877	870	854	204	106	107	110	119	4,185	107	104	106		
Annual Additions, Short Term Resources	-	50	352	830	842	932	892	933	992	1,311	1,454	1,521	1,642	1,745	1,870	1,919	738	773	807	863		
Total Annual Additions	277	890	1,047	2,359	1,614	1,856	1,805	1,957	1,868	2,181	2,308	1,725	1,749	1,853	1,980	2,038	4,923	880	912	968		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 44

PVRR: $21,249

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	54	246	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	195	105	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	-	-	-	200
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	141	132	-	273
	Wind, Project I	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	67	54	-	200
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	-	-	470	112	119	175	424	-	-	-	-	-	1,300
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	343	504	454	-	-	-	-	-	-	-	-	-	846	1,300
	Total Wind	99	99	-	-	-	-	-	335	661	750	454	670	112	119	175	424	100	180	208	186	1,944	4,571
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	-	-	-	2	2	2	2	2	2	2	2	-	5	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	92	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	42
	DSM, Class 2, UT	40	46	42	42	43	45	46	45	45	46	46	46	49	50	51	52	50	53	54	52	441	945
	DSM, Class 2, WY	-	3	5	8	8	8	8	9	9	9	9	9	9	9	9	10	10	10	10	10	66	161
	DSM, Class 2 Total	42	50	49	52	53	56	56	56	56	57	56	57	60	61	63	64	63	66	66	64	528	1,147
	FOT Mona Q3	-	-	-	152	200	200	200	200	81	-	-	-	31	118	200	200	200	200	200	200	103	119
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	378	386	376	480	480	480	578	600	600	600	600	86	302
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	29	33	-	12	36	84	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	100
	Wind, MC, 35	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	100	76	-	-	-	-	200
	Wind, WM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	474	-	-	-	-	500
	Wind, WM, 35	-	-	-	-	-	-	-	-	-	-	20	80	-	-	-	-	-	-	-	-	-	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	100	-	-	-	-	300
	Total Wind	45	20	-	-	-	-	-	-	-	-	120	80	-	-	124	326	650	-	-	-	65	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	-	-	-	-	-	-	-	-	-	1	1	1	2	4
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	26	26

Case # 44

PVRR: $21,249

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
DSM, Class 2, WM	28	28	30	30	30	30	31	31	30	20	20	20	20	20	20	20	20	20	20	20	289	491
DSM, Class 2, YA	5	6	5	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	54	115
DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	28	28	28	29	29	29	30	29	30	30	30	372	664
FOT COB Flat	-	-	206	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	238	288
FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	161	203	235	245	6	194	53	243	324	400	400	400	76	163
FOT MidColumbia Q3	-	-	-	155	186	300	347	-	-	-	-	-	-	-	-	-	-	-	-	-	99	49
FOT West Main Q3	-	-	-	-	50	50	50	50	50	-	-	-	-	-	28	-	50	50	50	50	25	24
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	N/A	9
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	247	66	215	-	-	54	185	234	N/A	125
Annual Additions, Long Term Resources	263	322	183	1,003	156	158	181	596	774	1,454	658	872	203	212	393	846	879	277	305	281		
Annual Additions, Short Term Resources	-	-	206	696	825	939	886	939	1,011	820	959	958	1,101	1,213	1,342	1,392	1,511	1,653	1,808	1,980		
Total Annual Additions	263	322	388	1,700	981	1,097	1,068	1,536	1,786	2,274	1,617	1,829	1,304	1,425	1,735	2,238	2,390	1,931	2,114	2,261		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 45

PVRR: $20,967

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero ID	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	397	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	598	598
	Total Wind	99	99	397	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,095	1,095
	CHP - Biomass	1	1	2	2	2	2	2	2	2	2	1	1	-	-	-	-	-	-	-	-	19	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	-	-	-	-	8	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1 & 3 Total	25	50	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	16	37
	DSM, Class 2, UT	37	41	42	42	43	44	43	41	46	47	47	48	49	51	52	52	50	53	54	52	427	935
	DSM, Class 2, WY	-	3	5	7	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	65	161
	DSM, Class 2 Total	38	45	48	51	53	54	53	51	57	58	58	59	60	62	64	64	63	66	66	64	508	1,133
	FOT Mona Q3	-	-	-	165	200	200	200	200	75	-	-	-	72	178	200	200	200	200	200	200	104	125
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	405	413	467	480	480	549	600	600	600	600	600	88	314
	FOT Utah Q3	-	-	-	-	-	-	33	35	-	-	-	-	-	-	-	-	-	-	-	-	7	3
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25	-	-	-	50
	CHP - Biomass	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	10	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	1	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	288	491
	DSM, Class 2, YA	4	6	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	369	662
	Micro Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.27	-	0
	FOT COB Flat	-	-	223	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	240	289
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	171	213	250	259	-	-	-	-	-	45	184	168	78	85
	FOT MidColumbia Q3	-	-	-	156	204	325	400	-	-	-	-	-	-	-	-	-	-	-	-	-	108	54
	FOT West Main Q3	-	-	-	-	50	50	50	50	50	-	-	-	50	50	50	50	50	50	50	50	25	33
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	96	96	91	133	112	118	124	150	N/A	115
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	159	287	433	595	N/A	188
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	172	178	197	141	178	134	-	-	N/A	125
	Annual Additions, Long Term Resources	251	310	574	1,497	150	149	112	414	116	707	91	92	93	94	131	96	117	121	96	94		
	Annual Additions, Short Term Resources	-	-	223	710	843	964	973	924	1,016	857	1,000	1,064	1,208	1,320	1,424	1,489	1,636	1,772	1,929	2,101		
	Total Annual Additions	251	310	798	2,206	993	1,114	1,085	1,338	1,132	1,565	1,091	1,157	1,301	1,414	1,555	1,585	1,754	1,892	2,025	2,195		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 46

PVRR: $21,532

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600
	IC Aero UT	-	-	-	-	174	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	174	174
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, GO, 29	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300
	Wind, WYNE, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	444	45	-	-	-	-	-	489
	Total Wind	99	99	-	-	-	140	160	100	-	-	300	-	-	-	444	45	-	-	-	-	598	1,386
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	17	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	3	2	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	26	47
	DSM, Class 2, UT	40	46	42	42	43	45	46	45	46	47	47	48	49	51	52	52	50	53	54	52	443	952
	DSM, Class 2, WY	-	3	5	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	66	162
	DSM, Class 2 Total	43	51	49	53	54	56	57	56	58	59	58	59	60	62	64	64	63	66	66	64	535	1,161
	FOT Mona Q3	-	-	-	151	144	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	130	165
	FOT Mead Q3	-	-	-	-	-	-	-	-	372	600	217	288	373	440	543	600	600	600	600	600	97	292
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	-	-	-	-	-	-	-	-	-	-	10	5
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	38	49	71	-	33	57	104	N/A	44
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	-	1	-	1	1	1	1	1	1	-	-	-	2	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	30	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	371	665
	FOT COB Flat	-	-	197	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	237	287
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	155	228	234	243	-	-	-	-	-	79	176	164	78	84
	FOT MidColumbia Q3	-	-	-	148	129	143	232	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT West Main Q3	-	-	-	-	-	39	50	50	50	50	-	-	50	50	50	50	50	50	50	50	24	32
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	68	69	82	120	84	91	116	138	N/A	96
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	345	467	582	N/A	203
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	184	190	189	138	189	110	-	-	N/A	125
	Annual Additions, Long Term Resources	263	322	383	1,004	329	298	282	249	117	109	989	91	93	94	539	140	92	95	96	94		
	Annual Additions, Short Term Resources	-	-	197	688	663	771	771	939	1,016	1,367	988	1,069	1,213	1,324	1,451	1,516	1,688	1,846	2,004	2,176		
	Total Annual Additions	263	322	581	1,691	991	1,069	1,053	1,188	1,133	1,476	1,977	1,159	1,305	1,419	1,990	1,657	1,781	1,941	2,099	2,270		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 47

PVRR: $20,863

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600
	IC Aero UT	-	-	-	-	174	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	174	174
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, GO, 24	-	-	-	-	-	-	-	-	52	171	-	-	-	-	-	-	-	-	-	-	223	223
	Wind, GO, 29	-	-	-	-	-	-	-	194	106	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	24	23	29	394	53	-	-	-	-	-	522
	Total Wind	99	99	-	-	-	-	-	333	158	331	-	24	23	29	394	53	-	-	-	-	1,020	1,542
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	16	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	43
	DSM, Class 2, UT	40	46	42	42	43	45	46	45	46	47	47	48	49	51	52	52	50	53	54	52	443	952
	DSM, Class 2, WY	-	3	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	66	163
	DSM, Class 2 Total	42	50	49	52	53	56	56	56	57	59	58	59	60	62	64	64	63	66	66	64	532	1,157
	FOT Mona Q3	-	-	-	152	144	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	130	165
	FOT Mead Q3	-	-	-	-	-	-	-	-	366	600	211	266	351	432	536	600	600	600	600	600	97	288
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	-	-	-	-	-	-	-	-	-	-	10	5
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	23	35	49	-	18	42	90	N/A	32
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	-	1	-	1	1	1	1	1	1	-	-	-	2	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	30	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	371	665
	FOT COB Flat	-	-	205	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	238	288
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	161	228	240	249	-	-	-	-	-	-	162	159	79	80
	FOT MidColumbia Q3	-	-	-	155	136	150	245	-	-	-	-	-	-	-	-	-	-	-	-	-	69	34
	FOT West Main Q3	-	-	-	-	-	44	50	50	50	50	-	-	50	50	50	50	50	50	50	50	24	32
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	96	96	91	132	111	118	124	149	N/A	115
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	338	460	575	N/A	197
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	162	169	187	132	168	169	13	-	N/A	125
	Annual Additions, Long Term Resources	263	322	183	1,003	329	158	122	490	275	440	688	115	115	123	489	148	92	95	96	94		
	Annual Additions, Short Term Resources	-	-	205	696	670	784	784	939	1,016	1,367	988	1,053	1,197	1,308	1,435	1,501	1,673	1,831	1,988	2,160		
	Total Annual Additions	263	322	389	1,699	999	942	906	1,429	1,291	1,807	1,677	1,168	1,312	1,430	1,924	1,649	1,765	1,926	2,084	2,254		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 48

PVRR: $41,268

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	25	275	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	171	129	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	281	300	129	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	281	300	268	750	171	154	275	-	-	-	-	-	-	-	-	-	-	2,398	2,398
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	6	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 3, GO-CPP-CI	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, GO-CPP-RES	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, GO-DemandB	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	0	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, GO-RTP-CI	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, GO-TOU-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, UT-CPP-CI	-	-	-	-	2	42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	44
	DSM, Class 3, UT-DemandB	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 3, UT-RTP-CI	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 3, WY-CPP-CI	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	16
	DSM, Class 3, WY-DemandB	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 3, WY-RTP-CI	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1 & 3 Total	39	50	40	30	13	86	10	26	10	10	-	-	-	-	-	-	-	-	-	-	314	314
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	45	46	51	50	52	51	55	54	54	56	58	62	59	55	57	56	475	1,040
	DSM, Class 2, WY	8	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	85	185
	DSM, Class 2 Total	53	59	55	55	56	57	62	61	64	63	66	65	66	68	70	74	72	68	70	68	582	1,269
	FOT Mona Q3	-	-	-	94	200	200	200	200	52	200	200	200	200	200	200	200	200	200	200	200	115	157
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Utah Q3	-	-	-	-	-	-	-	21	-	-	-	-	-	-	50	50	-	-	-	-	2	6
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	153	148	145	163	144	9	33	81	N/A	110
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	67	79	152	298	-	-	-	-	N/A	75
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 3, WW-DemandB	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, WW-RTP-CI	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, WM-RTP-CI	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, WM-DemandB	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 3, YA-DemandB	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, YA-RTP-CI	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1 & 3 Total	2	-	-	-	2	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12

Case # 48

PVRR: $41,268

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
DSM, Class 2, WM	14	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	276	481
DSM, Class 2, YA	5	6	6	5	5	6	6	5	6	6	6	6	6	6	7	7	7	7	7	7	56	121
DSM, Class 2 Total	21	37	39	39	39	39	39	39	40	30	30	30	30	29	30	31	30	30	30	30	362	663
FOT COB Flat	-	-	200	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	237	271
FOT COB Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	-	17
FOT Mid Columbia Flat	-	-	-	-	127	160	226	400	160	234	277	337	-	8	149	140	400	400	400	214	131	182
FOT MidColumbia Q3	-	-	-	153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	100	172	121	111	110	112	136	N/A	120
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	-	108	272	616	986	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	161	248	28	-	174	302	86	-	N/A	125
Annual Additions, Long Term Resources	270	326	184	1,288	692	499	897	349	284	388	99	97	98	100	102	107	102	98	100	98		
Annual Additions, Short Term Resources	-	-	200	687	767	799	766	910	981	1,324	1,464	1,525	1,664	1,771	1,902	1,960	2,125	2,281	2,435	2,604		
Total Annual Additions	270	326	384	1,975	1,459	1,299	1,662	1,259	1,265	1,712	1,563	1,622	1,762	1,871	2,004	2,067	2,227	2,379	2,535	2,702		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

B-Series Portfolio Summary Tables

Case 02b

PVRR: $22,040

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	550	750	-	-	-	-	-	-	1,300
	Total Wind	99	99	-	-	-	-	140	-	-	-	160	-	-	550	750	-	-	-	-	-	338	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.8	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	10.8	27.9	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	55	54	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	49.0	46	48	49	51	51	47	46	48	47	48	49	51	52	52	50	55	57	55	477	992
	DSM, Class 2, WY	1	3.4	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	70	167
	DSM, Class 2 Total	46	54.2	53	58	59	61	61	57	57	59	58	59	60	62	64	64	63	67	69	67	565	1,198
	FOT Utah Q3	-	-	-	29	50	50	50	50	-	-	-	-	-	-	50	-	-	-	-	-	23	14
	FOT Mead Q3	-	-	-	-	-	-	-	-	542	480	480	498	600	600	600	600	600	600	600	600	102	340
	FOT Mona/Nevada Utah Border	75	50	150	350	413	200	200	200	200	104	151	200	-	-	-	-	-	-	-	-	194	115
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	198	-	-	-	247	-	N/A	56
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	4	-	N/A	2
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	IC Aero	-	-	-	-	-	287	-	-	-	-	-	-	-	-	-	-	-	-	-	-	287	287
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	-	-	-	-	-	1	1	-	-	-	-	-	5	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	14	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 02b

PVRR: $22,040

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
DSM, Class 2, YA	5	6	6	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	55	116
DSM, Class 2 Total	36	37.2	39	39	39	39	40	39	38	29	29	29	30	29	29	30	29	30	30	30	375	668
FOT COB Flat	-	-	43	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	222	280
FOT Mid Columbia Flat	-	-	-	-	-	-	176	-	-	-	-	-	-	-	-	10	17	191	176	187	18	38
FOT MidColumbia Q3	-	-	-	392	400	400	224	400	-	-	-	-	-	-	-	-	-	-	-	-	182	91
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	120	126	136	116	173	230	530	N/A	191
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	249	314	-	286	394	348	213	196	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	10	175	200	187	158	156	283	N/A	146
Annual Additions, Long Term Resources	268	328	189	404	198	528	350	416	115	707	248	89	92	644	845	95	92	97	98	97		
Annual Additions, Short Term Resources	75	50	193	1,210	1,302	1,089	989	939	1,032	874	1,019	1,085	1,332	1,432	1,552	1,619	1,701	1,858	2,013	2,183		
Total Annual Additions	343	378	382	1,614	1,500	1,618	1,339	1,356	1,146	1,581	1,267	1,175	1,424	2,076	2,397	1,714	1,793	1,955	2,112	2,280		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05b

PVRR: $41,265

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	451	750	-	100	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	-	-	750	750	-	100	-	-	-	-	-	-	-	-	-	-	1,798	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	2.0	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	24.7	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.5	0.3	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	78	24	17	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	48.7	44	48	49	53	52	52	47	48	47	48	49	51	52	62	59	55	57	55	485	1,019
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	71	167
	DSM, Class 2 Total	45	53.4	52	58	59	64	63	63	58	59	58	59	60	62	64	74	71	67	69	67	574	1,225
	Fuel Cell	-	-	-	-	-	-	30	10	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	23	50	50	50	50	-	12	26	50	50	50	50	50	-	-	50	18	24	29
	FOT Mead Q3	-	-	-	-	-	-	-	-	540	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	350	415	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	204	122
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	204	200	198	219	-	-	128	52	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	370	268	267	95	-	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	143	223	223	412	-	-	-	-	N/A	125
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	SCCT Aero	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	130	130
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	5	9	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 05b

PVRR: $41,265

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	60
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
DSM, Class 2, YA	5	6	6	5	6	6	6	6	5	6	6	6	6	6	6	6	6	6	6	6	56	117
DSM, Class 2 Total	35	37.2	39	39	39	40	40	40	39	29	29	29	30	29	29	30	29	30	30	30	377	671
Fuel Cell	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Flat	-	-	45	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	183	243
FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	-	205	264	262	-	-	60	32	60	89	161	241	21	69
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	-	97	72	116	-	-	-	-	31	178	110	6	210	131
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	108	100	120	131	136	344	469	519	N/A	241
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47	658	447	290	558	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	0	148	207	199	375	358	364	348	N/A	250
Annual Additions, Long Term Resources	267	327	188	404	199	528	954	1,148	118	208	88	89	92	93	94	105	100	97	98	97		
Annual Additions, Short Term Resources	75	50	195	1,212	1,304	1,089	989	939	1,029	1,404	1,549	1,616	1,863	1,976	2,112	2,171	2,247	2,404	2,559	2,729		
Total Annual Additions	342	377	383	1,616	1,502	1,618	1,944	2,087	1,147	1,612	1,638	1,705	1,954	2,069	2,207	2,276	2,347	2,501	2,658	2,826		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05b_CCCT

PVRR: $41,325

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	CCCT F 2x1	-	-	-	-	-	536	-	-	-	-	-	-	-	-	-	-	-	-	-	-	536	536
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	750	550	-	-	-	-	-	-	-	-	-	750	1,300
	Total Wind	99	99	-	-	-	-	300	-	-	750	550	-	-	-	-	-	-	-	-	-	1,248	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	4	3.8	8	8	8	6	8	8	4	4	-	-	-	-	-	-	-	-	-	-	59	59
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	447	971
	DSM, Class 2, WY	-	3.1	6	8	8	8	9	9	9	9	9	9	9	9	10	10	10	10	10	10	68	165
	DSM, Class 2 Total	42	50.8	49	52	55	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	532	1,173
	FOT Utah Q3	-	-	-	48	50	-	27	50	-	-	-	1	50	50	50	50	-	-	50	-	17	21
	FOT Mead Q3	-	-	-	-	-	-	-	-	540	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	350	444	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	207	123
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	204	173	198	219	-	-	206	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	183	274	252	290	-	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	92	96	95	98	-	-	194	-	N/A	72
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	25	-	-	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	3	3	3	1	3	3	1	1	-	-	-	-	-	-	-	-	-	-	19	19
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	493
	DSM, Class 2, YA	5	6	5	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	372	665
	FOT COB Flat	-	-	65	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	185	244
	FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	-	206	244	263	22	65	80	92	87	157	246	204	21	83
	FOT MidColumbia Q3	-	-	-	400	400	331	400	400	-	95	92	137	-	-	-	14	311	243	154	196	203	159
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	101	145	154	145	141	400	411	N/A	201
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	651	57	667	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	182	199	273	245	166	299	318	316	N/A	250
	Annual Additions, Long Term Resources	258	317	183	396	193	691	421	390	118	858	639	91	93	94	94	95	471	97	123	97		
	Annual Additions, Short Term Resources	75	50	215	1,237	1,333	971	966	939	1,030	1,390	1,523	1,588	1,834	1,946	2,083	2,150	2,322	2,479	2,612	2,782		
	Total Annual Additions	333	367	398	1,634	1,526	1,662	1,387	1,329	1,147	2,249	2,162	1,679	1,927	2,040	2,177	2,245	2,793	2,576	2,735	2,879		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05b_WC_CCCT

PVRR: $41,271

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	CCCT F 2x1	-	-	-	-	-	570	-	-	-	-	-	-	-	-	-	-	-	-	-	-	570	570
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	750	550	-	-	-	-	-	-	-	-	-	750	1,300
	Total Wind	99	99	-	-	-	-	300	-	-	750	550	-	-	-	-	-	-	-	-	-	1,248	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	447	971
	DSM, Class 2, WY	-	3.1	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	68	164
	DSM, Class 2 Total	42	50.8	49	52	55	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	532	1,173
	FOT Utah Q3	-	-	-	50	50	-	17	45	-	-	-	-	50	50	50	50	-	-	50	-	16	21
	FOT Mead Q3	-	-	-	-	-	-	-	-	536	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	357	458	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	209	124
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	176	187	198	219	-	-	220	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	235	282	207	252	-	-	24	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	31	69	96	98	-	-	120	-	N/A	52
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	25	-	-	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	30	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	372	665
	FOT COB Flat	-	-	69	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	186	245
	FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	-	207	244	263	51	70	88	98	88	146	246	205	21	85
	FOT MidColumbia Q3	-	-	-	400	400	317	400	400	-	90	87	133	-	-	37	104	312	254	154	195	201	164
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	117	101	149	140	137	145	400	371	N/A	195
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	569	646	88	698	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	182	195	266	197	225	297	318	321	N/A	250
	Annual Additions, Long Term Resources	257	317	178	391	188	723	416	385	118	858	639	91	93	94	94	95	471	97	123	97		
	Annual Additions, Short Term Resources	75	50	219	1,247	1,347	956	957	935	1,025	1,386	1,518	1,584	1,830	1,942	2,078	2,145	2,318	2,474	2,607	2,777		
	Total Annual Additions	332	367	397	1,638	1,535	1,679	1,372	1,319	1,143	2,244	2,157	1,674	1,922	2,035	2,173	2,240	2,789	2,571	2,731	2,874		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 08b

PVRR: $41,922

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	23	177	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	305	277	134	584	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	305	300	750	744	-	-	-	-	-	-	-	-	-	-	-	-	-	2,298	2,298
	CHP - Biomass	2	2.0	2	2	1	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	6	4	4	-	-	-	-	-	-	-	-	-	-	66	66
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.4	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	100	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	58.9	49	51	53	56	54	50	53	51	55	54	54	56	58	62	59	55	57	56	523	1,088
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	50	64.5	57	62	64	67	65	61	64	62	66	65	66	68	70	74	72	68	70	68	617	1,303
	Fuel Cell	-	-	-	-	-	5	35	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	10	50	50	50	50	-	-	-	10	50	50	50	50	50	-	50	-	21	26
	FOT Mead Q3	-	-	-	-	-	-	-	-	535	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	350	295	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	192	116
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	93	106	216	228	221	-	136	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	192	193	321	244	50	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	179	292	79	130	215	-	104	-	N/A	125
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22
	DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 08b

PVRR: $41,922

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	292	497
DSM, Class 2, YA	6	6	6	6	6	6	6	5	6	6	6	6	6	6	7	7	7	7	7	7	60	126
DSM, Class 2 Total	37	38.1	40	40	40	41	40	39	40	30	30	30	30	29	30	31	30	30	30	30	385	685
Fuel Cell	-	-	-	-	-	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
FOT COB Flat	-	-	27	-	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	181	242
FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	39	39
FOT Mid Columbia Flat	-	-	-	-	400	400	351	180	-	260	348	400	36	10	83	70	251	372	285	279	159	186
FOT MidColumbia Q3	-	-	-	384	-	-	49	220	-	49	0	-	-	-	-	-	-	-	-	-	70	35
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	94	100	116	212	187	341	363	373	N/A	223
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	103	668	330	889	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	208	211	227	207	147	-	267	163	N/A	179
Annual Additions, Long Term Resources	274	339	194	726	773	1,055	966	417	125	113	98	96	97	99	101	107	102	98	100	98		
Annual Additions, Short Term Resources	75	50	177	1,183	1,184	1,089	989	939	1,024	1,398	1,536	1,598	1,840	1,948	2,080	2,138	2,213	2,368	2,523	2,754		
Total Annual Additions	349	389	371	1,909	1,957	2,144	1,955	1,356	1,149	1,511	1,634	1,694	1,937	2,047	2,181	2,244	2,314	2,467	2,623	2,853		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 09b

PVRR: $40,967

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	100	451	750	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	-	100	750	750	-	-	-	-	-	-	-	-	-	-	-	-	1,798	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	2.0	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	24.5	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	78	25	17	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	48.7	44	48	49	51	52	52	47	48	47	48	49	51	52	62	59	55	57	55	483	1,016
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	71	167
	DSM, Class 2 Total	45	53.3	52	58	59	61	63	63	58	59	58	59	60	62	64	74	71	67	69	67	572	1,223
	Fuel Cell	-	-	-	-	-	-	35	5	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	23	50	50	50	50	-	-	-	31	-	-	-	-	50	-	50	50	22	20
	FOT Mead Q3	-	-	-	-	-	-	-	-	340	517	564	600	600	600	600	600	600	600	600	600	86	341
	FOT Mona/Nevada Utah Border	75	50	150	350	415	200	200	200	-	200	200	200	-	-	-	-	-	-	-	-	184	112
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95	-	215	237	N/A	68
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	163	118	N/A	35
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	SCCT Aero	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	130	130
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	1.3	-	-	-	-	-	-	-	-	-	-	-	-	1.3	1.3
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	0.1	1.1	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	6	8	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 09b

PVRR: $40,967

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	60
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	21	290	494
DSM, Class 2, YA	5	6	6	5	5	6	6	6	5	6	6	6	6	6	6	6	6	6	6	6	56	117
DSM, Class 2 Total	35	37.2	39	39	39	40	40	40	39	29	29	29	30	29	29	30	29	30	30	30	377	671
Fuel Cell	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Flat	-	-	45	389	-	-	289	239	239	239	338	338	338	338	-	-	-	-	338	-	144	156
FOT COB Q3	-	-	-	-	389	389	-	-	-	-	-	-	-	-	338	338	338	338	-	338	78	123
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	280	340
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	180	129	134	214	208	338	395	402	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	267	319	544	210	396	41	224	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	298	194	274	27	300	285	310	312	N/A	250
Annual Additions, Long Term Resources	267	327	188	404	198	619	966	1,142	118	108	88	89	92	93	94	105	100	97	98	97		
Annual Additions, Short Term Resources	75	50	195	1,212	1,304	1,089	989	939	1,029	1,406	1,552	1,618	1,865	1,978	2,114	2,173	2,249	2,406	2,561	2,731		
Total Annual Additions	342	377	383	1,616	1,502	1,709	1,956	2,081	1,147	1,515	1,640	1,708	1,957	2,071	2,209	2,278	2,349	2,503	2,660	2,828		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 10b

PVRR: $40,904

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	269	31	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	389
	Wind, WYSW, 35	-	-	-	-	500	41	719	40	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	500	650	750	200	-	-	389	-	-	-	-	-	-	-	-	-	2,298	2,687
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	-	64	64
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.5	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	100	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	55.2	49	51	53	58	53	50	53	51	55	54	54	56	58	62	59	55	57	56	520	1,084
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	50	60.7	57	62	63	69	64	61	64	62	66	65	66	68	70	74	72	68	70	68	613	1,300
	Fuel Cell	-	-	-	-	5	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	4	50	50	50	50	-	-	-	5	50	50	50	50	50	-	50	-	20	25
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	594	600	600	600	600	600	600	600	600	600	600	107	354
	FOT Mona/Nevada Utah Border	75	50	150	350	373	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	200	120
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	91	88	87	108	104	-	136	-	N/A	77
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	150	182	257	57	19	-	336	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	37	82	167	34	77	-	327	-	N/A	90
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22
	DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 10b

PVRR: $40,904

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	292	497
DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	61	126
DSM, Class 2 Total	36	38.1	40	40	40	41	40	40	40	30	30	30	30	29	30	31	30	30	30	30	385	685
Fuel Cell	-	-	-	-	5	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
FOT COB Flat	-	-	30	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	221	279
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	55	315	343	400	400	400	400	400	400	400	400	400	237	316
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	120	127	129	121	126	135	148	N/A	128
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	241	621	-	848	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	5	33	-	78	207	228	146	303	N/A	125
Annual Additions, Long Term Resources	272	335	194	409	725	1,127	965	715	125	113	487	96	97	99	101	107	102	98	100	98		
Annual Additions, Short Term Resources	75	50	180	1,194	1,262	1,089	989	939	1,024	1,398	1,531	1,592	1,835	1,943	2,074	2,132	2,207	2,363	2,517	2,686		
Total Annual Additions	347	385	374	1,602	1,988	2,217	1,955	1,655	1,149	1,511	2,018	1,688	1,932	2,042	2,176	2,239	2,309	2,461	2,617	2,785		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 17b

PVRR: $51,819

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	139	-	161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	125	-	-	-	-	-	-	-	-	-	-	125	125
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	701	308	42	125	-	-	-	-	-	-	-	-	-	-	1,175	1,175
	Wind, WYSW, 35	-	-	362	99	201	589	50	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	362	438	500	750	750	308	42	250	-	-	-	-	-	-	-	-	-	-	3,598	3,598
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	-	64	64
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	2.5	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	97	14	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	50	58.9	49	52	58	58	60	52	53	57	55	56	56	58	59	73	65	62	60	60	547	1,151
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	64.5	58	62	69	69	71	63	65	68	67	67	68	70	71	86	77	76	73	73	641	1,369
	Fuel Cell	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	-	50	50	50	45	-	-	-	-	50	50	50	50	50	50	50	50	20	30
	FOT Mead Q3	-	-	-	-	-	-	-	-	529	600	600	600	600	600	600	600	600	600	600	600	113	356
	FOT Mona/Nevada Utah Border	75	50	150	350	240	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	187	113
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	91	88	87	122	30	23	285	275	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	96	194	241	163	-	-	138	167	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	61	61	88	130	-	-	313	347	N/A	125
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	38	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 29	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	138	62	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	765	765
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22

Case 17b

PVRR: $51,819

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	27	7	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34
DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	499
DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	62	131
DSM, Class 2 Total	37	38.2	40	40	40	41	41	40	40	30	30	30	31	30	31	31	31	31	31	31	387	694
Fuel Cell	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Flat	-	-	14	-	-	288	289	239	239	239	338	338	338	338	338	-	-	338	338	338	131	200
FOT COB Q3	-	-	-	389	389	101	-	-	-	-	-	-	-	-	-	338	338	-	-	-	88	78
FOT Mid Columbia Flat	-	-	-	-	400	400	184	159	-	231	334	322	224	119	272	338	400	400	341	343	137	223
FOT MidColumbia Q3	-	-	-	337	-	-	216	241	-	63	-	71	-	-	-	-	-	-	-	-	86	46
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	236	163	163	178	235	300	586	N/A	247
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	711	750	357	182	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	197	191	169	152	116	176	-	-	N/A	125
Annual Additions, Long Term Resources	276	339	695	921	777	1,038	974	726	168	869	99	99	101	102	103	118	984	106	104	104		
Annual Additions, Short Term Resources	75	50	164	1,127	1,130	1,089	989	935	1,019	1,384	1,521	1,581	1,821	1,927	2,057	2,106	2,471	2,621	2,772	2,937		
Total Annual Additions	351	389	859	2,048	1,907	2,127	1,963	1,660	1,186	2,253	1,620	1,680	1,921	2,029	2,160	2,225	3,455	2,727	2,876	3,040		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 18b

PVRR: $50,597

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	6	86	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	173	173
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	199	101	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	154	346	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	186	606	8	-	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	-	-	486	201	351	263	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	486	500	750	550	606	162	346	-	-	-	-	-	-	-	-	-	-	3,598	3,598
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	-	64	64
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.6	4.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	100	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	55.3	49	52	53	58	53	50	53	51	55	54	56	58	59	73	64	62	60	60	521	1,122
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	50	60.9	57	62	64	69	64	61	64	62	66	65	68	70	71	85	77	75	73	73	614	1,337
	Fuel Cell	-	-	-	-	5	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	-	50	50	50	43	-	-	-	-	-	-	-	-	50	50	50	50	19	20
	FOT Mead Q3	-	-	-	-	-	-	-	-	326	495	535	596	600	600	600	600	600	600	600	600	82	338
	FOT Mona/Nevada Utah Border	75	50	150	344	290	200	200	200	-	200	200	200	-	-	-	-	-	-	-	-	171	105
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	-	104	133	136	126	N/A	71
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	148	305	376	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139	333	416	N/A	111
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22

Case 18b

PVRR: $50,597

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	292	497
DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	61	126
DSM, Class 2 Total	36	38.1	40	40	40	41	40	40	40	30	30	30	30	29	30	31	30	30	30	30	385	686
Fuel Cell	-	-	-	-	5	5	25	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
FOT COB Flat	-	-	30	389	-	-	289	239	-	-	338	338	338	338	338	-	338	338	338	338	95	199
FOT COB Q3	-	-	-	-	389	389	-	-	239	239	-	-	-	-	-	338	-	-	-	-	126	80
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	280	340
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	120	127	339	330	322	334	315	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	296	424	182	229	143	291	215	221	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	27	-	298	156	291	157	19	53	N/A	125
Annual Additions, Long Term Resources	275	377	194	907	784	1,057	960	1,022	286	458	98	96	99	101	102	118	983	106	103	103		
Annual Additions, Short Term Resources	75	50	180	1,183	1,179	1,089	989	932	1,015	1,384	1,522	1,584	1,825	1,931	2,062	2,111	2,477	2,627	2,778	2,944		
Total Annual Additions	350	427	374	2,090	1,963	2,147	1,950	1,954	1,301	1,843	1,620	1,680	1,924	2,032	2,164	2,229	3,460	2,732	2,882	3,047		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 47b

PVRR: $21,785

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600
	IC Aero	-	-	-	-	348	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	609	609
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	171	-	-	-	-	-	-	-	-	-	-	221	221
	Wind, GO, 29	-	-	-	-	-	-	4	187	108	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	23	750	527	-	-	-	-	-	1,300
	Total Wind	99	99	-	-	-	-	4	327	158	331	-	-	-	23	750	527	-	-	-	-	1,018	2,318
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.2	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	24.1	14.6	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	11	39	71	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	2.0	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	43
	DSM, Class 2, UT	41	48.7	44	44	49	51	51	45	46	48	47	48	49	51	52	52	50	53	54	55	467	979
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	69	166
	DSM, Class 2 Total	43	53.7	52	55	60	62	62	56	57	59	58	59	60	62	64	64	63	66	66	67	559	1,187
	FOT Utah Q3	-	-	-	28	-	50	50	50	-	50	-	-	-	50	-	-	-	-	-	-	23	14
	FOT Mead Q3	-	-	-	-	-	-	-	-	526	600	480	517	600	600	600	600	600	600	600	600	113	346
	FOT Mona/Nevada Utah Border	75	50	150	350	200	200	200	200	200	200	170	200	-	-	-	-	-	-	-	-	183	110
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	178	173	170	39	-	18	42	90	N/A	89
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	62	105	64	-	-	-	-	-	N/A	29
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	4.2	4.2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	13	-	-	-	-	-	-	-	-	-	-	-	-	-	33	33

Case 47b

PVRR: $21,785

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
DSM, Class 2, YA	5	6	6	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	55	116
DSM, Class 2 Total	35	36.5	39	39	39	39	40	39	39	29	29	29	30	29	29	30	29	30	30	30	375	668
FOT COB Flat	-	-	47	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	222	280
FOT Mid Columbia Flat	-	-	-	-	-	-	-	203	-	227	-	-	-	-	27	128	104	167	178	202	43	62
FOT MidColumbia Q3	-	-	-	400	390	400	400	197	-	-	-	-	-	-	-	-	-	-	-	-	179	89
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	-	-	50	50	50	50	50	50	50	50	35	38
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	73	74	75	103	99	104	103	153	N/A	98
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	24	33	155	298	393	520	577	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	177	178	182	160	156	147	N/A	125
Annual Additions, Long Term Resources	265	326	187	400	511	214	230	717	275	440	688	89	92	116	844	622	92	95	96	97		
Annual Additions, Short Term Resources	75	50	197	1,217	1,030	1,089	989	939	1,015	1,366	987	1,054	1,301	1,413	1,534	1,589	1,672	1,830	1,987	2,157		
Total Annual Additions	340	376	385	1,617	1,541	1,303	1,220	1,657	1,291	1,806	1,676	1,143	1,392	1,529	2,378	2,212	1,764	1,925	2,083	2,254		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

RESOURCE DIFFERENCES, B-SERIES LESS CORRESPONDING ORIGINAL PORTFOLIOS

Table A.19 – Resource Capacity Differences, Case 2B less Original Case 2 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Dist. Gen	4	4	4	4	4	16	6	6	2	(1)	(1)	(1)	50	41
	Wind	-	-	-	-	-	-	140	-	-	(140)	-	-	-	659
	DSM	2.9	3.4	4.2	6.6	6.0	52.8	51.7	6.3	-	0.4	-	-	134.3	135.8
	Market Purchase	75	50	150	259	263	50	41	6	175	173	210	271	124	48
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		58
West															
	Gas	-	-	-	-	-	287	-	-	-	-	-	-	287	287
	Dist. Gen	2	2	2	2	2	2	2	2	-	-	-	(1)	17	13
	Other Renewables	-	-	-	-	-	-	25	25	-	-	-	-	50	50
	DSM	0.5	0.7	0.6	0.1	1.1	20.8	15.5	0.5	(0.5)	-	-	-	39.6	39.6
	Market Purchase	-	-	(176)	237	222	101	-	-	(170)	(163)	(200)	(259)	5	(9)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		62
	Annual Additions, Long Term Resources	10	10	11	(594)	13	379	240	40	1	(140)	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(26)	495	485	151	41	6	5	10	11	12		
	Total Annual Additions	85	60	(15)	(99)	498	530	280	46	6	(129)	10	11		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.20 – Resource Capacity Differences, Case 5B less Original Case 5 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Clean Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	(346)
	Gas	-	-	-	-	-	261	-	(261)	-	-	-	-	-	-
	Dist. Gen	4	4	4	4	4	16	34	14	-	-	(1)	(1)	84	81
	Wind	-	-	-	-	-	-	451	750	-	(651)	(400)	-	550	-
	Other Renewables	-	-	-	-	-	-	-	35	-	-	-	-	35	35
	DSM	2.9	3.1	3.0	6.6	4.1	76.2	22.2	14.1	-	-	-	-	132.1	142.1
	Market Purchase	75	50	150	252	265	50	50	25	196	12	26	50	113	(14)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		149
West															
	Gas	-	-	-	-	-	-	-	130	-	-	-	-	130	130
	Dist. Gen	2	2	2	2	2	2	2	12	-	-	(1)	(1)	25	22
	Other Renewables	-	-	-	-	-	-	25	60	-	-	-	-	85	85
	DSM	1.3	0.7	0.6	0.1	1.5	21.5	6.3	9.7	-	-	-	-	41.8	41.8
	Market Purchase	-	-	(175)	244	222	104	4	-	(171)	27	23	(0)	26	(45)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		233
	Annual Additions, Long Term Resources	11	10	10	(594)	11	376	539	763	-	(651)	(402)	(1)		
	Annual Additions, Short Term Resources	75	50	(25)	496	487	154	54	25	25	39	49	50		
	Total Annual Additions	86	60	(15)	(98)	498	530	593	788	25	(611)	(353)	49		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.21 – Resource Capacity Differences, Case 5B CCCT Dry less Original Case 5B Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	536	-	-	-	-	-	-	536	536
	Dist. Gen	-	-	4	4	4	2	4	4	-	-	-	-	21	21
	Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-
	DSM	0.2	0.5	-	-	-	-	0.8	-	-	-	-	-	1.4	1.4
	Market Purchase	75	50	150	277	294	-	27	25	196	-	-	1	109	(20)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		96
West															
	Dist. Gen	-	-	2	2	2	-	2	2	-	-	-	-	8	8
	Other Renewables	-	-	-	-	-	-	-	-	-	-	-	-	-	50
	DSM	1.3	-	-	-	0.2	0.5	0.1	-	-	-	-	-	2.1	2.1
	Market Purchase	-	-	(156)	244	222	35	4	-	(171)	25	22	21	20	(2)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		193
	Annual Additions, Long Term Resources	2	0	5	(601)	6	539	6	5	-	-	150	-		
	Annual Additions, Short Term Resources	75	50	(6)	521	516	35	30	25	25	25	22	22		
	Total Annual Additions	77	50	(1)	(80)	522	574	36	31	25	25	172	22		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.22 – Resource Capacity Differences, Case 5B CCCT Wet less Original Case 5 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	570	-	-	-	-	-	-	570	570
	Dist. Gen	-	-	-	1	-	-	-	-	-	-	-	-	1	-
	Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-
	Market Purchase	75	50	150	286	308	-	17	21	192	-	-	-	110	(20)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		76
West															
	Dist. Gen	-	-	-	-	1	-	-	-	-	-	-	-	1	0
	Other Renewables	-	-	-	-	-	-	-	-	-	-	-	-	-	50
	DSM	1.3	-	-	-	-	0.2	0.1	-	-	-	-	-	1.6	1.6
	Market Purchase	-	-	(151)	244	222	21	4	-	(171)	21	18	18	19	6
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		187
	Annual Additions, Long Term Resources	1	0	-	(606)	1	570	0	-	-	-	150	-		
	Annual Additions, Short Term Resources	75	50	(1)	531	530	21	21	21	21	21	18	18		
	Total Annual Additions	76	50	(1)	(76)	531	591	21	21	21	21	167	18		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.23 – Resource Capacity Differences, Case 8B less Original Case 8 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	3	1	1	7	(1)	5	29	(2)	-	-	(1)	(1)	42	40
	Wind	-	-	-	41	-	464	(6)	(193)	(158)	(249)	-	-	(100)	(100)
	Other Renewables	-	-	-	-	35	-	-	-	-	-	-	-	35	35
	DSM	5.0	10.1	5.2	7.2	4.3	94.9	3.7	(6.1)	(0.0)	(0.5)	-	-	123.9	123.9
	Market Purchase	75	50	150	271	156	50	50	-	177	-	-	10	98	(18)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		252
West															
	Dist. Gen	2	1	1	-	-	5	30	(2)	-	-	(1)	(1)	37	35
	Other Renewables	-	-	-	-	35	-	-	(35)	-	-	-	-	-	-
	DSM	0.8	0.9	0.8	1.4	1.3	35.7	1.1	(0.6)	-	-	-	-	41.4	41.4
	Market Purchase	-	-	(174)	230	270	180	119	-	(163)	40	36	27	50	(28)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		151
	Annual Additions, Long Term Resources	11	12	7	(550)	75	605	58	23	(158)	(249)	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(24)	501	425	230	169	-	14	40	36	37		
	Total Annual Additions	86	62	(17)	(50)	500	835	227	23	(144)	(209)	34	35		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.24 – Resource Capacity Differences, Case 9B less Original Case 9 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Clean Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	(346)
	Gas	-	-	-	-	-	261	-	(261)	-	-	-	-	-	-
	Dist. Gen	4	4	4	4	4	10	45	9	-	-	(1)	(1)	84	81
	Wind	-	-	-	-	-	100	451	750	(444)	(536)	(305)	(15)	320	0
	Other Renewables	-	-	-	-	-	-	-	35	-	-	-	-	35	35
	DSM	2.9	2.5	3.0	6.6	6.1	73.8	22.7	13.8	-	-	-	-	131.3	141.3
	Market Purchase	75	50	150	373	465	152	52	24	33	45	52	53	142	4
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		104
West															
	Gas	-	-	-	-	-	-	-	130	-	-	-	-	130	130
	Dist. Gen	2	2	2	2	2	2	2	12	-	-	(1)	(1)	26	22
	Other Renewables	-	-	-	-	-	-	25	60	-	-	-	-	85	85
	DSM	1.3	0.7	0.6	0.1	1.2	21.5	6.7	9.1	-	-	-	-	41.3	41.4
	Market Purchase	-	-	(175)	124	21	-	-	-	-	-	-	-	(3)	(1)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		127
	Annual Additions, Long Term Resources	11	10	10	(594)	13	468	551	757	(444)	(536)	(306)	(16)		
	Annual Additions, Short Term Resources	75	50	(25)	497	486	152	52	24	33	45	52	53		
	Total Annual Additions	86	60	(15)	(97)	499	620	603	781	(411)	(492)	(254)	38		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.25 – Resource Capacity Differences, Case 10B less Original Case 10 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	4	4	4	4	21	9	20	(4)	-	-	(1)	(1)	61	60
	Wind	-	-	-	-	139	359	-	(191)	(158)	(248)	189	-	(100)	89
	Other Renewables	-	-	-	-	-	35	-	(35)	-	-	-	-	-	-
	DSM	6.8	7.0	5.2	7.2	7.9	97.1	2.1	(6.0)	(0.1)	(0.5)	-	-	126.7	126.7
	Market Purchase	75	50	150	354	423	187	73	(0)	122	114	69	28	155	18
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		266
West															
	Dist. Gen	2	2	2	2	7	7	32	(2)	-	-	(1)	(1)	51	49
	Wind	-	-	-	-	-	100	-	(100)	-	-	-	-	-	-
	Other Renewables	-	-	-	-	-	35	-	(35)	-	-	-	-	-	-
	DSM	0.5	1.0	0.8	1.6	1.3	35.3	0.5	-	-	-	-	-	41.0	41.0
	Market Purchase	-	-	(183)	134	42	-	50	-	(107)	(74)	(7)	36	(14)	(5)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		16
	Annual Additions, Long Term Resources	14	14	12	(593)	175	677	54	(111)	(158)	(249)	188	(1)		
	Annual Additions, Short Term Resources	75	50	(33)	488	465	187	123	(0)	14	40	62	63		
	Total Annual Additions	89	64	(21)	(105)	640	863	177	(112)	(144)	(209)	251	62		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.26 – Resource Capacity Differences, Case 17B less Original Case 17 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	4	4	4	4	4	4	44	-	-	-	(1)	(1)	67	66
	Wind	-	-	169	138	-	-	(0)	(288)	(68)	(250)	-	-	(300)	(300)
	DSM	7.2	4.0	0.5	3.0	8.6	94.3	12.5	(0.4)	(7.3)	(0.4)	-	-	121.9	121.9
	Market Purchase	75	50	150	265	171	68	50	45	182	-	-	-	106	(7)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		310
West															
	Dist. Gen	2	2	2	2	2	2	12	-	-	-	(1)	(1)	22	21
	Wind	-	-	138	(138)	-	-	-	-	-	500	-	-	500	500
	DSM	0.8	1.0	0.6	0.7	0.9	27.7	7.9	0.1	(0.2)	-	-	-	39.6	39.6
	Market Purchase	-	-	(183)	189	271	257	239	14	(111)	97	92	94	77	13
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		77
	Annual Additions, Long Term Resources	14	11	313	(598)	15	127	76	(27)	(76)	249	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(33)	454	442	326	289	60	71	97	92	94		
	Total Annual Additions	89	61	281	(144)	457	453	364	33	(5)	346	91	92		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.27 – Resource Capacity Differences, Case 18B less Original Case 18 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	4	4	4	4	9	9	34	-	-	-	(1)	-	66	66
	Wind	-	-	-	223	-	-	264	206	(588)	(404)	-	-	(300)	(300)
	DSM	6.8	6.9	5.2	7.2	4.9	97.0	1.6	(0.4)	(6.1)	(0.5)	-	-	122.6	127.0
	Market Purchase	75	50	150	344	340	250	219	29	21	71	70	70	155	28
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		144
West															
	Dist. Gen	2	2	2	2	7	7	27	-	-	-	(1)	(1)	47	46
	Other Renewables	-	-	-	-	35	(35)	-	-	-	-	-	-	-	-
	DSM	0.5	0.9	0.8	1.7	1.3	35.0	0.5	-	-	-	-	-	40.7	40.7
	Market Purchase	-	-	(182)	140	95	29	20	-	26	3	-	-	13	7
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		122
	Annual Additions, Long Term Resources	14	14	12	(370)	56	112	326	467	(594)	(405)	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(32)	484	434	279	240	29	46	74	70	70		
	Total Annual Additions	89	64	(20)	114	491	391	566	496	(548)	(331)	68	69		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

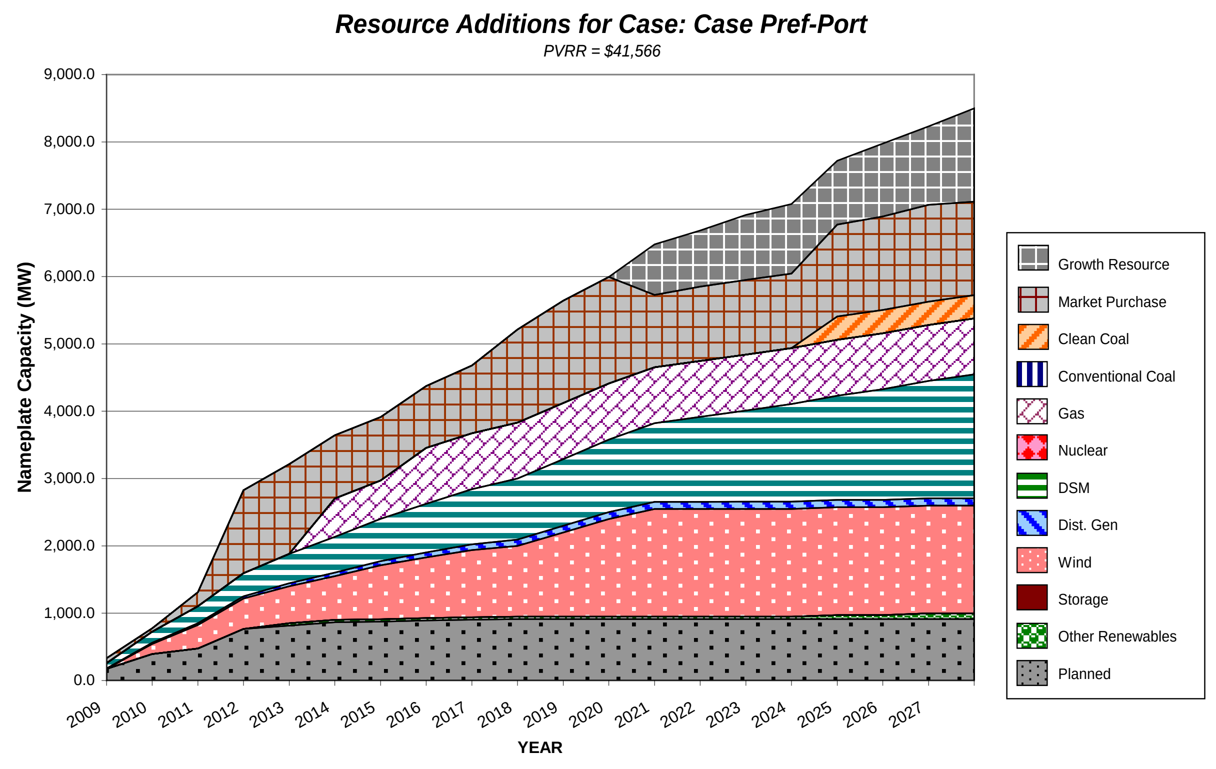
Table A.28 – Resource Capacity Differences, Case 47B less Original Case 47 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	174	-	-	261	-	-	-	-	435	435
	Dist. Gen	1	1	1	1	-	-	-	-	-	-	(1)	(1)	2	(0)
	Wind	-	-	-	-	-	-	4	(6)	(0)	-	-	(24)	(2)	776
	DSM	0.9	3.3	2.2	2.4	6.3	34.7	66.1	(5.8)	-	0.7	0.4	-	110.8	114.3
	Market Purchase	75	50	150	227	56	50	50	-	160	-	239	250	82	12
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		86
West															
	Dist. Gen	1	1	1	1	1	-	-	-	1	-	-	(1)	4	0
	Other Renewables	-	-	-	-	-	-	25	-	-	-	-	-	25	25
	DSM	-	-	0.6	0.1	1.1	20.8	13.3	(21.5)	0.1	-	-	-	14.7	14.7
	Market Purchase	-	-	(158)	295	304	256	155	-	(161)	(1)	(240)	(249)	69	34
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		36
	Annual Additions, Long Term Resources	2	4	4	(603)	182	55	109	228	0	1	(0)	(25)		
	Annual Additions, Short Term Resources	75	50	(8)	521	360	306	205	-	(1)	(1)	(1)	1		
	Total Annual Additions	77	54	(4)	(82)	542	361	314	228	(0)	(0)	(1)	(25)		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

2008 PREFERRED PORTFOLIO

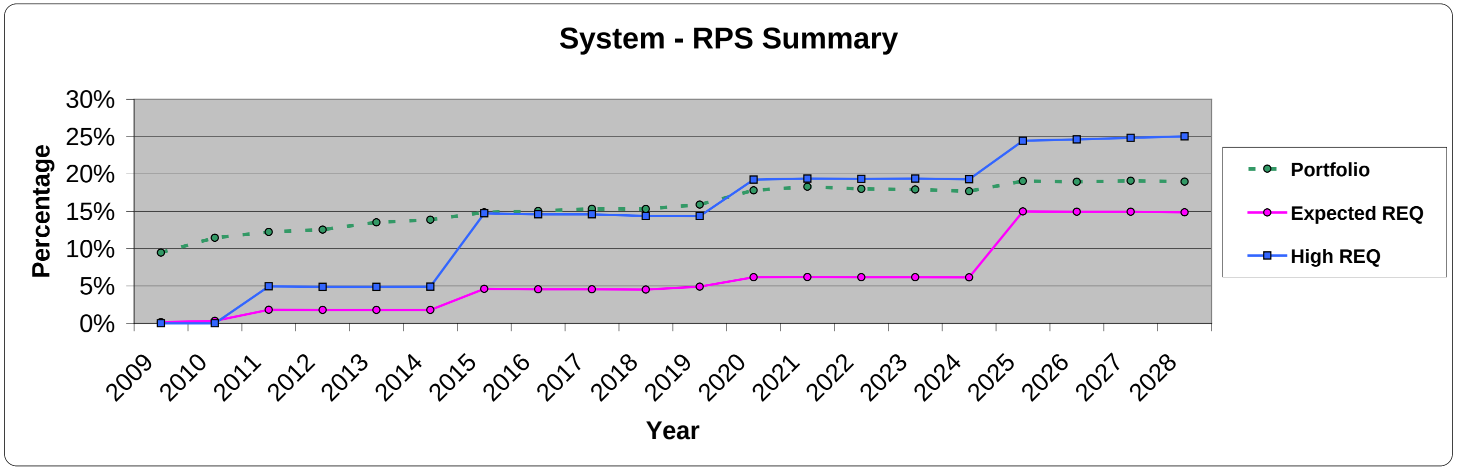
This section consists of tables and charts showing System Optimizer results for the 2008 IRP preferred portfolio.



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

System - RPS Report - Case # Pref-Port

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,912	12,527	16,289	20,396	24,704	29,132	33,718	38,459	43,277	48,380	53,776	59,382	64,937	70,507	76,072	76,484	76,874	77,311	77,737
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	336	582	516	598	686	507	325	372	406	211	46	117	135	118	110	111	106	104	101
Oregon	1,376	2,640	3,322	4,080	4,987	5,946	5,455	5,031	4,659	4,322	4,116	3,250	2,454	1,601	713	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,887**	**16,432**	**20,885**	**25,982**	**31,336**	**35,094**	**39,073**	**43,490**	**48,004**	**52,707**	**57,072**	**61,953**	**66,673**	**71,338**	**76,182**	**76,595**	**76,980**	**77,415**	**77,838**
Adjusted Qualifying Renewables																				
Utah	2,950	3,361	3,616	3,762	4,107	4,307	4,428	4,586	4,741	4,818	5,104	5,396	5,606	5,555	5,570	5,565	5,670	5,690	5,795	5,817
Other (ID,WY)	823	1,130	1,263	1,354	1,521	1,622	1,686	1,781	1,867	1,902	2,059	2,227	2,347	2,315	2,320	2,280	2,346	2,363	2,430	2,446
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	336	368	391	451	479	520	547	572	586	634	679	714	705	704	703	713	708	717	712
Oregon	982	1,264	1,383	1,465	1,627	1,691	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**6,266**	**6,815**	**7,166**	**7,910**	**8,314**	**9,086**	**9,391**	**9,689**	**9,836**	**10,360**	**11,733**	**12,139**	**12,069**	**12,121**	**12,107**	**13,142**	**13,201**	**13,422**	**13,495**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	12%	13%	14%	14%	15%	15%	15%	15%	16%	18%	18%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II - CCCT -WC)

APPENDIX B – STOCHASTIC PRODUCTION COST SIMULATION RESULTS

This appendix reports additional results for the Monte Carlo production cost simulations conducted with PacifiCorp's Planning and Risk model. These results supplement the data presented in Chapter 8 of the main IRP document. The results presented include the following:

- Stochastic risk and other portfolio performance measures for the additional portfolios modeled to support a 2012 gas resource deferral strategy (referred to as the "B series" in this appendix)
- A component cost breakdown of the stochastic mean Present Value of Revenue Requirements (PVRR) reported for all the portfolios.

Table B.1 – Stochastic Mean PVRR by CO_2 Tax Level, B Series Portfolios

	CO2 Tax (Million 2009$)			
Case	$0/ton	$45/ton	$100/ton	Average
2B	22,126	40,062	60,448	40,879
5B	22,554	39,452	58,664	40,224
5B_CCCT Dry	22,462	39,369	58,751	40,194
5B_CCCT Wet	22,457	39,315	58,639	40,137
8B	23,402	39,673	57,809	40,295
9B	22,778	39,725	59,031	40,511
10B	23,921	40,261	58,542	40,908
17B	25,569	40,539	56,798	40,968
18B	25,102	40,353	57,136	40,864
47B	22,658	40,507	60,872	41,346

Table B.2 – Stochastic Risk Results by CO_2 Tax Level, B Series Portfolios

	Risk Measure by CO2 Tax Level (Million 2009$)			
Case	Production Cost Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
$0/ton CO2 Tax				
2B	8,702	12,646	36,914	50,630
5B	8,859	13,441	37,820	51,782
5B_CCCT Dry	9,140	13,595	37,386	52,993
5B_CCCT Wet	9,103	13,601	37,349	52,874
8B	8,267	14,270	37,697	50,203
9B	8,955	13,644	38,113	52,426
10B	8,350	14,832	38,506	51,241
17B	7,583	16,363	38,434	49,330
18B	7,905	15,901	38,712	50,424

Case	Risk Measure by CO2 Tax Level (Million 2009$)			
	Production Cost Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
47B	8,737	13,367	37,074	51,363
$45/ton CO2 Tax				
2B	11,114	25,686	59,314	73,178
5B	11,211	25,130	59,065	73,171
5B_CCCT Dry	11,480	24,932	58,565	74,252
5B_CCCT Wet	11,433	24,917	58,391	74,029
8B	10,593	26,224	58,397	70,946
9B	11,303	25,304	59,415	73,857
10B	10,720	26,463	59,354	72,143
17B	9,825	26,977	57,866	68,742
18B	10,178	27,621	58,429	70,111
47B	11,165	26,098	59,398	73,800
$100/ton CO2 Tax				
2B	16,792	38,762	90,087	106,209
5B	16,817	36,998	88,526	104,917
5B_CCCT Dry	17,186	37,396	88,207	106,410
5B_CCCT Wet	17,142	37,433	87,959	106,144
8B	16,038	36,943	86,765	101,179
9B	16,912	37,252	88,957	105,723
10B	16,250	37,635	88,046	102,765
17B	14,990	37,546	84,231	96,591
18B	15,453	37,354	85,373	98,767
47B	16,941	39,461	90,319	107,006
CO2 Tax Average				
2B	12,202	25,698	62,105	76,672
5B	12,296	25,190	61,804	76,623
5B_CCCT Dry	12,602	25,308	61,386	77,885
5B_CCCT Wet	12,559	25,317	61,233	77,682
8B	11,633	25,813	60,953	74,109
9B	12,390	25,400	62,162	77,335
10B	11,773	26,310	61,969	75,383
17B	10,799	26,962	60,177	71,554
18B	11,179	26,959	60,838	73,101
47B	12,281	26,308	62,264	77,390

Table B.3 – B Series Cases, Portfolio Emissions Externality Cost by CO_2 Adder Level

Case	Incremental Stochastic Mean PVRR by CO_2 Tax Level (Million 2009$)			
	$0/ton	$45/ton	$100/ton	Average
2B	0	17,936	38,322	28,129
5B	0	16,898	36,110	26,504
5B_CCCT Dry	0	16,907	36,289	26,598

Case	Incremental Stochastic Mean PVRR by CO_2 Tax Level (Million 2009$)			
	$0/ton	$45/ton	$100/ton	Average
5B_CCCT Wet	0	16,858	36,182	26,520
8B	0	16,272	34,408	25,340
9B	0	16,947	36,253	26,600
10B	0	16,340	34,620	25,480
17B	0	14,970	31,228	23,099
18B	0	15,252	32,034	23,643
47B	0	17,848	38,214	28,031

Table B.4 – B Series Cases, CO_2 Cost Exposure (non-weighted)

Case	CO2 Opportunity Loss by CO2 Tax Level, Million Dollars (2009$)			Maximum Loss	Rank
	$0/ton	$45/ton	$100/ton		
2B	-	793	3,943	3,943	9
5B	474	171	2,081	2,081	4
5B_CCCT Dry	360	62	2,152	2,152	5
5B_CCCT Wet	353	-	2,028	2,028	3
8B	1,315	359	1,139	1,315	1
9B	712	461	2,470	2,470	6
10B	1,875	994	1,935	1,935	2
17B	3,520	1,198	-	3,520	8
18B	3,066	1,040	396	3,066	7
47B	541	1,242	4,379	4,379	10

Table B.5 – B Series Cases, Customer Rate Impact

Case	Customer Rate Impact by CO2 Tax Level ($/MWh)				Rank
	$0/ton	$45/ton	$100/ton	Average	
2B	3.00	6.42	10.12	6.51	8
5B	3.03	6.25	9.74	6.34	4
5B_CCCT Dry	3.06	6.22	9.65	6.31	2
5B_CCCT Wet	3.05	6.20	9.62	6.29	1
8B	3.19	6.31	9.62	6.38	5
9B	3.02	6.24	9.73	6.33	3
10B	3.32	6.45	9.79	6.52	10
17B	3.67	6.43	9.26	6.45	7
18B	3.59	6.40	9.32	6.44	6
47B	3.05	6.43	10.08	6.52	9

Table B.6 – B Series Cases, Average Annual Energy Not Served

Case	Energy Not Served, Average Annual GWh, 2009-2028	Rank
2B	132.2	3
5B	169.7	9
5B_CCCT Dry	153.7	6
5B_CCCT Wet	152.4	5
8B	154.5	7
9B	184.3	10
10B	156.7	8
17B	131.7	2
18B	144.6	4
47B	131.3	1

Table B.7 – B Series Cases, Loss of Load Probability for a Major July Event

Case	Probability of ENS Event > 25,000 MWh in July (Annual average, 2009-2028)	Rank
2B	16.7%	1
5B	18.2%	7
5B_CCCT Dry	17.8%	6
5B_CCCT Wet	17.8%	5
8B	17.7%	4
9B	19.3%	10
10B	18.4%	8
17B	17.1%	2
18B	17.1%	2
47B	18.5%	9

Table B.8 – B Series Cases, Capital Costs for 2009-2018

Case	Net Present Value, (Thousand 2009$)	Rank
2B	580,304	1
5B	1,271,802	5
5B_CCCT Dry	744,635	3
5B_CCCT Wet	756,891	4
8B	2,417,994	8
9B	1,335,078	6
10B	2,164,993	7
17B	3,624,235	10
18B	3,013,923	9
47B	641,136	2

PROBABILITY-WEIGHTED STOCHASTIC MEASURE RESULTS

Tables B.9 and B.10 report the stochastic cost results for expected value CO_2 tax levels ranging from $15 to $70. The expected value CO_2 tax levels reflect probability weights applied to stochastic mean cost values for the three Monte Carlo simulations conducted for each portfolio at $0, $45, and $100 CO_2 tax values.

Table B.9 – Original Portfolio Stochastic Cost Results

	Expected Value CO2 Tax ($/ton)											
Case	**$15**	**$20**	**$25**	**$30**	**$35**	**$40**	**$45**	**$50**	**$55**	**$60**	**$65**	**$70**
Risk-adjusted PVRR, Million Dollars (2009$)												
1	30,487	32,588	34,505	36,603	38,708	40,813	42,918	45,022	47,127	51,632	51,337	53,442
2	29,962	32,050	33,955	36,002	38,056	40,110	42,164	44,218	46,272	50,677	50,380	52,434
3	32,372	34,236	35,936	37,697	39,464	41,231	42,998	44,765	46,533	50,961	50,067	51,834
5	30,453	32,423	34,219	36,152	38,092	40,031	41,971	43,910	45,850	50,226	49,729	51,668
8	30,789	32,681	34,406	36,234	38,068	39,903	41,737	43,571	45,406	49,734	49,074	50,909
9	30,575	32,544	34,339	36,272	38,210	40,149	42,087	44,026	45,965	50,352	49,842	51,781
10	31,504	33,389	35,109	36,948	38,794	40,639	42,484	44,330	46,175	50,588	49,866	51,712
11	33,043	34,845	36,489	38,192	39,900	41,609	43,318	45,026	46,735	51,191	50,153	51,862
14	34,835	36,586	38,183	39,808	41,439	43,070	44,702	46,333	47,964	52,537	51,226	52,858
17	32,562	34,305	35,895	37,559	39,230	40,900	42,570	44,240	45,910	50,297	49,250	50,920
18	32,478	34,247	35,861	37,558	39,262	40,965	42,669	44,372	46,075	50,480	49,482	51,186
19	32,937	34,686	36,281	37,954	39,633	41,311	42,990	44,669	46,348	50,780	49,706	51,385
20	35,293	36,904	38,373	39,885	41,403	42,920	44,438	45,955	47,473	52,022	50,508	52,026
22	36,646	38,279	39,769	41,277	42,791	44,305	45,820	47,334	48,849	53,523	1,877	53,392
24	37,077	38,624	40,037	41,471	42,911	44,350	45,790	47,230	48,670	53,339	51,549	52,989
25	34,237	35,896	37,410	38,976	40,548	42,120	43,692	45,264	46,836	51,318	49,979	51,551
26	36,850	38,424	39,860	41,330	42,808	44,285	45,762	47,239	48,716	53,392	51,670	53,148
27	37,041	38,591	40,005	41,441	42,883	44,324	45,766	47,208	48,650	53,317	51,533	52,975
29	39,348	40,885	42,289	43,709	45,136	46,563	47,990	49,416	50,843	55,730	53,697	55,124
46	31,620	33,678	35,556	37,571	39,592	41,614	43,635	45,656	47,678	52,224	51,720	53,742
47	30,622	32,689	34,574	36,600	38,632	40,665	42,697	44,730	46,763	51,219	50,828	52,861
Cost Exposure for CO2 Tax Scenarios, Million Dollars (2009$)												
1	646	698	745	997	1,250	1,503	1,756	2,009	2,262	2,564	2,768	3,021
2	120	160	195	397	599	801	1,003	1,205	1,407	1,609	1,811	2,013
3	2,530	2,345	2,176	2,091	2,007	1,922	1,837	1,752	1,668	1,893	1,498	1,413
5	612	532	460	547	634	722	810	897	985	1,158	1,160	1,247
8	948	790	646	629	611	593	576	558	541	667	505	488
9	734	653	580	666	753	839	926	1,013	1,100	1,284	1,273	1,360
10	1,662	1,499	1,349	1,343	1,336	1,330	1,323	1,317	1,310	1,521	1,297	1,291
11	3,201	2,954	2,729	2,586	2,443	2,300	2,157	2,013	1,870	2,123	1,584	1,441
14	4,993	4,695	4,423	4,203	3,982	3,761	3,540	3,320	3,099	3,470	2,658	2,437
17	2,720	2,414	2,136	1,954	1,772	1,590	1,408	1,227	1,045	1,230	681	499
18	2,636	2,356	2,102	1,953	1,804	1,656	1,507	1,359	1,210	1,412	913	765
19	3,096	2,795	2,521	2,348	2,175	2,002	1,829	1,656	1,483	1,713	1,137	964
20	5,451	5,013	4,614	4,280	3,945	3,611	3,277	2,942	2,608	2,955	1,939	1,605
22	6,804	6,388	6,009	5,671	5,334	4,996	4,659	4,321	3,984	4,455	3,308	2,971
24	7,235	6,734	6,277	5,865	5,453	5,041	4,629	4,217	3,805	4,271	2,981	2,568

	Expected Value CO2 Tax ($/ton)											
Case	**$15**	**$20**	**$25**	**$30**	**$35**	**$40**	**$45**	**$50**	**$55**	**$60**	**$65**	**$70**
25	4,396	4,005	3,651	3,371	3,091	2,811	2,531	2,251	1,971	2,251	1,410	1,130
26	7,009	6,533	6,100	5,725	5,350	4,975	4,601	4,226	3,851	4,324	3,101	2,727
27	7,200	6,700	6,245	5,835	5,425	5,015	4,605	4,195	3,785	4,249	2,964	2,554
29	9,507	8,995	8,529	8,104	7,679	7,253	6,828	6,403	5,978	6,662	5,128	4,703
46	1,778	1,788	1,797	1,965	2,135	2,304	2,474	2,643	2,813	3,157	3,151	3,321
47	780	798	814	994	1,175	1,356	1,536	1,717	1,898	2,151	2,259	2,440
Customer Rate Impact, Dollars per MWh (2009$)												
1	4.00	4.38	4.73	5.09	5.46	5.82	6.19	6.56	6.92	7.57	7.66	8.02
2	4.05	4.43	4.77	5.13	5.49	5.85	6.21	6.56	6.92	7.57	7.64	8.00
3	4.54	4.88	5.19	5.51	5.82	6.13	6.44	6.76	7.07	7.73	7.69	8.01
5	4.03	4.37	4.69	5.02	5.35	5.68	6.00	6.33	6.66	7.29	7.32	7.65
8	4.14	4.48	4.79	5.11	5.43	5.75	6.07	6.39	6.71	7.34	7.35	7.67
9	4.01	4.35	4.67	5.00	5.33	5.66	5.99	6.32	6.65	7.27	7.30	7.63
10	4.28	4.62	4.93	5.25	5.57	5.89	6.21	6.53	6.85	7.49	7.49	7.81
11	4.32	4.64	4.93	5.21	5.50	5.79	6.08	6.37	6.65	7.28	7.23	7.52
14	5.07	5.38	5.67	5.96	6.24	6.53	6.81	7.10	7.38	8.08	7.96	8.24
17	4.41	4.72	4.99	5.27	5.54	5.82	6.10	6.38	6.65	7.28	7.21	7.49
18	4.56	4.87	5.15	5.44	5.72	6.01	6.29	6.58	6.87	7.51	7.44	7.72
19	4.60	4.91	5.18	5.46	5.74	6.03	6.31	6.59	6.87	7.52	7.43	7.71
20	5.05	5.31	5.55	5.78	6.02	6.25	6.48	6.72	6.95	7.61	7.42	7.65
22	5.64	5.91	6.17	6.41	6.66	6.90	7.15	7.39	7.64	8.36	8.13	8.38
24	6.00	6.25	6.48	6.71	6.93	7.15	7.38	7.60	7.83	8.57	8.27	8.50
25	4.84	5.13	5.39	5.66	5.92	6.18	6.44	6.71	6.97	7.63	7.50	7.76
26	5.88	6.13	6.36	6.59	6.82	7.05	7.28	7.51	7.74	8.47	8.19	8.42
27	5.74	5.98	6.20	6.41	6.63	6.84	7.05	7.27	7.48	8.19	7.91	8.12
29	6.47	6.72	6.95	7.16	7.38	7.60	7.82	8.04	8.25	9.04	8.69	8.91
46	4.31	4.69	5.02	5.38	5.73	6.08	6.44	6.79	7.14	7.81	7.85	8.20
47	4.15	4.52	4.86	5.21	5.57	5.92	6.28	6.63	6.99	7.64	7.70	8.05
Upper-tail Mean PVRR, Million Dollars (2009$)												
1	65,144	67,632	69,883	72,746	75,620	78,495	81,369	84,243	87,118	95,741	92,866	95,741
2	58,812	61,294	63,542	66,332	69,134	71,935	74,736	77,537	80,338	88,256	85,941	88,742
3	51,373	53,739	55,883	58,419	60,964	63,509	66,055	68,600	71,146	78,099	76,236	78,782
5	60,337	62,706	64,850	67,535	70,231	72,927	75,623	78,319	81,016	89,016	86,408	89,104
8	56,895	59,185	61,259	63,809	66,369	68,929	71,490	74,050	76,610	84,155	81,731	84,291
9	60,620	62,983	65,122	67,802	70,493	73,183	75,874	78,565	81,256	89,281	86,638	89,329
10	59,030	61,205	63,174	65,694	68,225	70,756	73,287	75,819	78,350	86,114	83,412	85,943
11	51,781	54,099	56,200	58,681	61,172	63,662	66,153	68,644	71,135	78,089	76,116	78,607
14	51,809	54,091	56,159	58,561	60,974	63,386	65,798	68,210	70,622	77,512	75,446	77,859
17	55,938	58,085	60,028	62,399	64,780	67,161	69,542	71,922	74,303	81,616	79,064	81,445
18	56,883	59,050	61,013	63,422	65,841	68,260	70,679	73,098	75,517	82,957	80,355	82,775
19	56,912	59,053	60,992	63,367	65,752	8,137	70,522	72,907	75,292	82,709	80,062	82,448
20	53,336	55,469	57,401	59,677	61,963	64,249	66,535	68,821	71,107	78,070	75,679	77,965
22	52,314	54,504	56,487	58,758	61,039	63,319	65,599	67,879	70,159	76,996	74,719	76,999
24	53,427	55,521	57,417	59,616	61,824	64,032	66,240	68,448	70,656	77,562	75,072	77,281
25	54,523	56,606	58,492	60,786	63,089	65,393	67,696	70,000	72,303	79,418	76,910	79,214
26	54,074	56,181	58,089	60,327	62,573	64,820	67,067	69,313	71,560	78,565	76,053	78,300

Case	Expected Value CO2 Tax ($/ton)											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
27	53,182	55,277	57,174	59,374	61,582	63,791	66,000	68,209	70,417	77,299	74,835	77,044
29	55,173	57,264	59,158	61,330	63,512	65,693	67,875	70,057	72,238	79,293	76,601	78,783
46	59,779	62,233	64,455	67,209	69,973	72,738	75,502	78,267	81,032	89,019	86,561	89,326
47	59,158	61,626	63,860	66,634	69,419	72,203	74,988	77,773	80,557	88,498	86,127	88,912
Standard Deviation of Production Costs, Million Dollars (2009$)												
1	11,320	11,591	11,837	12,259	12,683	13,107	13,531	13,955	14,379	15,852	15,227	15,651
2	9,650	9,929	10,181	10,601	11,023	11,445	11,867	12,289	12,711	14,012	13,555	13,977
3	7,287	7,548	7,784	8,165	8,547	8,929	9,311	9,694	10,076	11,106	10,840	11,223
5	9,911	10,186	10,434	10,850	11,268	11,685	12,103	12,521	12,938	14,263	13,774	14,192
8	8,916	9,188	9,433	9,835	10,239	10,642	11,046	11,450	11,853	13,065	12,661	13,064
9	9,941	10,213	10,459	10,873	11,288	11,704	12,119	12,534	12,950	14,276	13,781	14,196
10	9,294	9,535	9,753	10,145	10,539	10,932	11,326	11,719	12,113	13,362	12,900	13,294
11	7,274	7,526	7,754	8,126	8,499	8,872	9,244	9,617	9,990	11,013	10,736	11,109
14	6,837	7,075	7,290	7,643	7,998	8,353	8,708	9,063	9,418	10,383	10,128	10,483
17	8,241	8,502	8,738	9,121	9,506	9,891	10,276	10,661	11,045	12,174	11,815	12,200
18	8,463	8,726	8,964	9,352	9,741	10,130	10,520	10,909	11,298	12,453	12,077	12,466
19	8,362	8,621	8,855	9,237	9,620	10,004	10,388	10,771	11,155	12,295	11,922	12,306
20	7,058	7,293	7,505	7,850	8,196	8,542	8,888	9,234	9,580	10,559	10,272	10,618
22	6,538	6,758	6,958	7,286	7,616	7,946	8,276	8,606	8,936	9,852	9,596	9,926
24	6,602	6,828	7,033	7,363	7,695	8,026	8,357	8,689	9,020	9,942	9,682	10,014
25	7,567	7,814	8,038	8,400	8,764	9,129	9,493	9,857	10,221	11,266	10,949	11,313
26	6,810	7,043	7,254	7,592	7,931	8,271	8,610	8,949	9,289	10,237	9,967	10,307
27	6,578	6,801	7,003	7,329	7,656	7,983	8,310	8,637	8,964	9,880	9,618	9,945
29	6,575	6,787	6,980	7,294	7,611	7,927	8,243	8,559	8,875	9,783	9,507	9,823
46	9,483	9,761	10,012	10,431	10,851	11,271	11,691	12,111	12,531	13,814	13,371	13,791
47	9,573	9,854	10,108	10,531	10,955	11,379	11,803	12,227	12,651	13,945	13,499	13,923

Table B.10 – Stochastic Cost Results based on Probability-weighted CO_2 Tax Levels

Case	Expected Value CO2 Tax											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
Risk-adjusted PVRR, Weighted Averages, Million Dollars (2009$)												
2B	30,457	32,553	34,459	36,501	38,550	40,599	42,649	44,698	46,747	48,796	50,845	52,896
5B	30,558	32,534	34,330	36,256	38,188	40,120	42,052	43,985	45,917	47,849	49,781	51,716
5B_CCCT Dry	30,446	32,422	34,219	36,154	38,095	40,037	41,978	43,920	45,861	47,803	49,744	51,688
5B_CCCT Wet	30,420	32,390	34,181	36,111	38,046	39,982	41,917	43,853	45,789	47,724	49,660	51,598
8B	31,177	33,081	34,811	36,648	38,491	40,334	42,177	44,020	45,863	47,707	49,550	51,395
9B	30,814	32,795	34,596	36,530	38,470	40,409	42,349	44,289	46,229	48,168	50,108	52,051
10B	31,763	33,675	35,413	37,262	39,116	40,971	42,826	44,681	46,536	48,391	50,246	52,103
17B	32,917	34,671	36,265	37,934	39,610	41,286	42,962	44,638	46,314	47,990	49,666	51,344
18B	32,564	34,350	35,974	37,686	39,405	41,123	42,841	44,560	46,278	47,996	49,715	51,436
47B	30,966	33,053	34,949	36,986	39,030	41,074	43,118	45,161	47,205	49,249	51,293	53,339
Cost Exposure for CO2 Tax Scenarios, Million Dollars (2009$)												
2B	270	357	437	634	831	1,028	1,225	1,422	1,619	1,816	2,014	2,211
5B	371	338	308	388	468	548	629	709	790	870	950	1,031
5B_CCCT Dry	259	226	196	286	376	465	555	644	734	824	913	1,003

Case	Expected Value CO2 Tax											
	$15	**$20**	**$25**	**$30**	**$35**	**$40**	**$45**	**$50**	**$55**	**$60**	**$65**	**$70**
5B_CCCT Wet	233	194	159	243	326	410	494	578	661	745	829	913
8B	990	885	789	780	772	763	754	745	736	727	718	710
9B	627	599	574	662	750	838	926	1,013	1,101	1,189	1,277	1,365
10B	1,576	1,479	1,391	1,394	1,397	1,400	1,403	1,406	1,409	1,412	1,415	1,418
17B	2,730	2,475	2,243	2,067	1,891	1,715	1,539	1,363	1,187	1,011	835	659
18B	2,377	2,155	1,952	1,818	1,685	1,551	1,418	1,284	1,151	1,017	884	750
47B	780	857	927	1,118	1,310	1,502	1,694	1,886	2,078	2,270	2,462	2,654
Customer Rate Impact, Dollars per MWh (2009$)												
2B	4.16	4.54	4.88	5.24	5.59	5.95	6.30	6.66	7.02	7.37	7.73	8.09
5B	4.13	4.48	4.80	5.14	5.47	5.81	6.14	6.48	6.81	7.15	7.49	7.82
5B_CCCT Dry	4.13	4.48	4.80	5.13	5.46	5.79	6.11	6.44	6.77	7.10	7.43	7.76
5B_CCCT Wet	4.12	4.47	4.78	5.11	5.44	5.77	6.10	6.43	6.75	7.08	7.41	7.74
8B	4.26	4.60	4.91	5.23	5.55	5.87	6.20	6.52	6.84	7.16	7.48	7.80
9B	4.11	4.47	4.79	5.12	5.46	5.80	6.13	6.47	6.80	7.14	7.47	7.81
10B	4.38	4.73	5.04	5.36	5.69	6.01	6.33	6.66	6.98	7.30	7.63	7.95
17B	4.61	4.91	5.19	5.47	5.75	6.02	6.30	6.58	6.86	7.14	7.42	7.70
18B	4.55	4.86	5.14	5.42	5.71	6.00	6.28	6.57	6.85	7.14	7.43	7.71
47B	4.20	4.57	4.91	5.26	5.61	5.96	6.31	6.66	7.01	7.37	7.72	8.07
Upper-tail Mean PVRR, Dollars per MWh (2009$)												
2B	58,307	60,787	63,042	65,810	68,589	71,368	74,147	76,926	79,705	82,484	85,263	88,047
5B	59,065	61,417	63,556	66,203	68,859	71,516	74,173	76,830	79,486	82,143	84,800	87,462
5B_CCCT Dry	60,232	62,570	64,696	67,356	70,027	72,698	75,369	78,040	80,710	83,381	86,052	88,728
5B_CCCT Wet	60,077	62,404	64,520	67,173	69,836	72,500	75,163	77,827	80,490	83,154	85,817	88,486
8B	57,266	59,548	61,622	64,161	66,709	69,258	71,807	74,356	76,904	79,453	82,002	84,556
9B	59,723	62,080	64,224	66,878	69,543	72,207	74,872	77,537	80,202	82,867	85,532	88,202
10B	58,358	60,657	62,747	65,313	67,889	70,465	73,042	75,618	78,194	80,770	83,346	85,928
17B	55,940	58,075	60,016	62,370	64,733	67,096	69,459	71,822	74,185	76,548	78,911	81,279
18B	57,128	59,293	61,262	63,669	66,086	68,504	70,921	73,338	75,755	78,172	80,589	83,012
47B	59,003	61,471	63,714	66,486	69,268	72,050	74,832	77,615	80,397	83,179	85,961	88,748
Standard Deviation of Production Costs, Million Dollars (2009$)												
2B	9,524	9,789	10,030	10,433	10,837	11,242	11,646	12,051	12,455	12,860	13,264	13,670
5B	9,660	9,919	10,154	10,550	10,948	11,346	11,744	12,142	12,540	12,938	13,336	13,735
5B_CCCT Dry	9,937	10,195	10,429	10,829	11,232	11,634	12,036	12,439	12,841	13,243	13,645	14,049
5B_CCCT Wet	9,897	10,154	10,387	10,787	11,189	11,591	11,992	12,394	12,796	13,198	13,600	14,003
8B	9,059	9,315	9,548	9,935	10,323	10,712	11,101	11,489	11,878	12,266	12,655	13,044
9B	9,755	10,013	10,248	10,644	11,042	11,440	11,838	12,236	12,634	13,031	13,429	13,828
10B	9,158	9,418	9,655	10,049	10,444	10,839	11,234	11,629	12,024	12,419	12,814	13,209
17B	8,347	8,593	8,818	9,186	9,557	9,927	10,297	10,668	11,038	11,409	11,779	12,150
18B	8,680	8,930	9,157	9,533	9,910	10,287	10,665	11,042	11,420	11,797	12,174	12,553
47B	9,564	9,831	10,074	10,482	10,893	11,303	11,713	12,123	12,533	12,944	13,354	13,765

PORTFOLIO MEASURE RANKINGS AND PREFERENCE SCORES

Tables (B.11 through B.22) display the portfolio measure ranking and preference scores based on probability-weighted CO_2 tax levels from \$15/ton to \$70/ton at \$5 increments (The two non-cost-based measures, average annual ENS and LOLP, are not probability-weighted.) Tables are shown for the original 21 portfolios and the additional 10 portfolios developed to determine the 2012 gas resource deferral strategy associated with the termination of the Lake Side 2 combined-cycle plant construction contract (“B” series portfolios).

Table B.23 shows portfolio measure ranking and preference scores for the additional 10 gas resource deferral strategy portfolios given an alternate importance weighting scheme with the following characteristics:

- The mean PVRR substitutes for the risk-adjusted PVRR measure
- The mean upper-tail PVRR risk measure is added
- The mean PVRR and upper-tail PVRR measures are given importance weights of 25% and 20% respectively (importance weights for all other measures remain unchanged)

The purpose of this alternative ranking scheme is to show the portfolio performance impact of heavily weighting upper-tail risk as a separate measure.

Table B.11 – \$15/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	1.5	1.0	1.0	1.5	10.0	10.0	10	**2.7**	**2.4**
2	1.0	1.2	1.3	1.0	6.9	3.9	2.1	**1.5**	**1.0**
3	3.3	3.0	6.7	3.3	2.4	2.0	2.1	**3.2**	**3.1**
5	1.5	1.1	1.6	1.5	7.3	5.2	4.6	**2.0**	**1.6**
8	1.8	1.5	4.3	1.8	5.5	5.1	7.6	**2.5**	**2.2**
9	1.6	1.0	1.8	1.6	7.4	5.9	5.8	**2.2**	**1.8**
10	2.5	2.0	3.8	2.5	6.2	5.5	8.9	**3.1**	**3.0**
11	4.0	2.2	7.1	4.0	2.4	2.2	2.9	**3.5**	**3.5**
14	5.7	4.9	9.7	5.7	1.6	1.4	1.3	**5.1**	**5.5**
17	3.5	2.5	6.6	3.5	4.2	4.2	6.6	**3.7**	**3.7**
18	3.4	3.1	5.4	3.4	4.6	4.4	7.8	**3.8**	**3.8**
19	3.9	3.2	6.4	3.9	4.4	4.4	7.1	**4.1**	**4.2**
20	6.1	4.8	8.0	6.1	2.0	2.1	4.3	**5.4**	**5.9**
22	7.4	7.0	10.0	7.4	1.0	1.0	1.0	**6.5**	**7.2**
24	7.8	8.3	9.6	7.8	1.1	1.1	1.5	**7.0**	**7.9**
25	5.1	4.1	8.0	5.1	2.9	3.1	5.1	**4.8**	**5.1**
26	7.6	7.8	9.6	7.6	1.5	1.5	3.4	**6.9**	**7.8**
27	7.8	7.3	9.6	7.8	1.1	1.3	2.6	**6.9**	**7.7**
29	10.0	10.0	9.7	10.0	1.1	1.0	1.7	**8.7**	**10.0**
46	2.6	2.1	2.7	2.6	6.5	4.8	9.0	**3.1**	**3.0**
47	1.6	1.5	1.5	1.6	6.7	4.5	6.9	**2.3**	**1.9**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	1.1	1.9	1.0	3.0	7.7	1.2	1	**1.5**	**1.2**
5B	1.5	1.2	3.0	4.0	8.4	7.5	6.3	**2.4**	**2.2**
5B_CCCT Dry	1.1	1.4	1.5	2.0	10.0	4.8	4.9	**1.6**	**1.3**
5B_CCCT Wet	1.0	1.2	1.5	1.0	9.8	4.6	4.7	**1.4**	**1.0**
8B	3.7	3.6	6.4	7.0	5.0	4.9	4.5	**4.2**	**4.5**
9B	2.4	1.0	3.2	5.0	9.0	10.0	10.0	**3.2**	**3.3**
10B	5.8	5.9	5.7	8.0	5.6	5.3	6.8	**5.9**	**6.6**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.7	8.9	8.2	9.0	2.9	3.3	2.2	**7.7**	**8.9**
47B	3.0	2.6	1.2	6.0	7.9	1.0	7.4	**3.2**	**3.3**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.12 – $20/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	1.5	1.1	1.0	1.5	10.0	10.0	10	**2.7**	**2.4**
2	1.0	1.3	1.3	1.0	6.9	3.9	2.1	**1.6**	**1.0**
3	3.2	3.0	6.7	3.2	2.5	2.0	2.1	**3.2**	**3.1**
5	1.4	1.1	1.6	1.4	7.4	5.2	4.6	**2.0**	**1.5**
8	1.6	1.5	4.3	1.6	5.5	5.1	7.6	**2.4**	**2.1**
9	1.5	1.0	1.8	1.5	7.4	5.9	5.8	**2.1**	**1.7**
10	2.4	2.0	3.8	2.4	6.2	5.5	8.9	**3.0**	**2.9**
11	3.8	2.1	7.1	3.8	2.4	2.2	2.9	**3.5**	**3.4**
14	5.6	4.9	9.7	5.6	1.6	1.4	1.3	**5.1**	**5.4**
17	3.3	2.4	6.6	3.3	4.2	4.2	6.6	**3.5**	**3.5**
18	3.2	3.0	5.4	3.2	4.7	4.4	7.8	**3.6**	**3.6**
19	3.7	3.1	6.4	3.7	4.5	4.4	7.1	**3.9**	**4.0**
20	5.9	4.6	8.0	5.9	2.0	2.1	4.3	**5.3**	**5.7**
22	7.3	6.9	10.0	7.3	1.0	1.0	1.0	**6.4**	**7.2**
24	7.7	8.2	9.6	7.7	1.1	1.1	1.5	**6.9**	**7.8**
25	4.9	4.0	8.0	4.9	3.0	3.1	5.1	**4.7**	**5.0**
26	7.5	7.8	9.6	7.5	1.5	1.5	3.4	**6.8**	**7.7**
27	7.7	7.2	9.6	7.7	1.1	1.3	2.6	**6.8**	**7.6**
29	10.0	10.0	9.7	10.0	1.1	1.0	1.7	**8.7**	**10.0**
46	2.7	2.3	2.7	2.7	6.6	4.8	9.0	**3.2**	**3.1**
47	1.7	1.6	1.5	1.7	6.8	4.5	6.9	**2.3**	**1.9**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	1.6	2.4	1.0	4.0	7.7	1.2	1	**2.0**	**1.8**
5B	1.6	1.3	3.0	3.0	8.5	7.5	6.3	**2.2**	**2.1**
5B_CCCT Dry	1.1	1.3	1.5	2.0	10.0	4.8	4.9	**1.6**	**1.3**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.7	3.7	6.4	7.0	5.1	4.9	4.5	**4.3**	**4.6**
9B	2.6	1.0	3.2	5.0	9.0	10.0	10.0	**3.3**	**3.4**
10B	6.1	6.3	5.7	8.0	5.6	5.3	6.8	**6.1**	**6.8**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.7	8.9	8.2	9.0	2.9	3.3	2.2	**7.7**	**8.9**
47B	3.6	3.1	1.2	6.0	8.0	1.0	7.4	**3.6**	**3.8**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.13 – \$25/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	1.6	1.2	1.0	1.6	10.0	10.0	10	**2.7**	**2.5**
2	1.0	1.4	1.3	1.0	6.9	3.9	2.1	**1.6**	**1.0**
3	3.1	3.1	6.7	3.1	2.5	2.0	2.1	**3.2**	**3.0**
5	1.3	1.1	1.6	1.3	7.4	5.2	4.6	**1.9**	**1.4**
8	1.5	1.5	4.3	1.5	5.6	5.1	7.6	**2.3**	**1.9**
9	1.4	1.0	1.8	1.4	7.5	5.9	5.8	**2.1**	**1.6**
10	2.2	2.0	3.8	2.2	6.2	5.5	8.9	**3.0**	**2.7**
11	3.7	2.0	7.1	3.7	2.5	2.2	2.9	**3.4**	**3.3**
14	5.6	5.0	9.7	5.6	1.6	1.4	1.3	**5.0**	**5.4**
17	3.1	2.3	6.6	3.1	4.3	4.2	6.6	**3.4**	**3.3**
18	3.1	2.9	5.4	3.1	4.7	4.4	7.8	**3.5**	**3.5**
19	3.5	3.0	6.4	3.5	4.5	4.4	7.1	**3.8**	**3.8**
20	5.8	4.5	8.0	5.8	2.0	2.1	4.3	**5.2**	**5.6**
22	7.3	6.9	10.0	7.3	1.0	1.0	1.0	**6.4**	**7.1**
24	7.6	8.2	9.6	7.6	1.1	1.1	1.5	**6.8**	**7.7**
25	4.7	3.9	8.0	4.7	3.0	3.1	5.1	**4.6**	**4.8**
26	7.4	7.7	9.6	7.4	1.5	1.5	3.4	**6.8**	**7.6**
27	7.5	7.0	9.6	7.5	1.1	1.3	2.6	**6.7**	**7.4**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	2.7	2.4	2.7	2.7	6.6	4.8	9.0	**3.3**	**3.1**
47	1.7	1.8	1.5	1.7	6.8	4.5	6.9	**2.3**	**1.9**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
2B	2.2	3.2	1.0	4.0	7.8	1.2	1	**2.4**	**2.3**
5B	1.6	1.4	3.0	3.0	8.5	7.5	6.3	**2.3**	**2.2**
5B_CCCT Dry	1.2	1.3	1.5	2.0	10.0	4.8	4.9	**1.6**	**1.4**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.7	3.8	6.4	6.0	5.1	4.9	4.5	**4.1**	**4.4**
9B	2.8	1.1	3.2	5.0	9.0	10.0	10.0	**3.4**	**3.5**
10B	6.3	6.7	5.7	8.0	5.7	5.3	6.8	**6.3**	**7.1**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.7	8.9	8.2	9.0	2.9	3.3	2.2	**7.7**	**8.9**
47B	4.3	3.8	1.2	7.0	8.0	1.0	7.4	**4.2**	**4.5**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.14 – $30/ton Expected-value CO$_2$ Tax

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1	1.7	1.4	1.0	1.7	10.0	10.0	10	**2.8**	**2.6**
2	1.0	1.5	1.3	1.0	7.0	3.9	2.1	**1.6**	**1.0**
3	3.0	3.1	6.7	3.0	2.6	2.0	2.1	**3.1**	**2.9**
5	1.2	1.1	1.6	1.2	7.4	5.2	4.6	**1.9**	**1.3**
8	1.3	1.5	4.3	1.3	5.6	5.1	7.6	**2.2**	**1.7**
9	1.3	1.0	1.8	1.3	7.5	5.9	5.8	**2.0**	**1.5**
10	2.1	2.0	3.8	2.1	6.2	5.5	8.9	**2.9**	**2.6**
11	3.6	1.9	7.1	3.6	2.5	2.2	2.9	**3.2**	**3.1**
14	5.4	5.0	9.7	5.4	1.6	1.4	1.3	**5.0**	**5.3**
17	2.8	2.1	6.6	2.8	4.3	4.2	6.6	**3.2**	**3.0**
18	2.8	2.8	5.4	2.8	4.7	4.4	7.8	**3.4**	**3.2**
19	3.3	2.9	6.4	3.3	4.5	4.4	7.1	**3.7**	**3.6**
20	5.5	4.3	8.0	5.5	2.0	2.1	4.3	**5.0**	**5.3**
22	7.2	6.9	10.0	7.2	1.0	1.0	1.0	**6.3**	**7.0**
24	7.4	8.1	9.6	7.4	1.1	1.1	1.5	**6.7**	**7.5**
25	4.5	3.7	8.0	4.5	3.0	3.1	5.1	**4.4**	**4.5**
26	7.2	7.6	9.6	7.2	1.6	1.5	3.4	**6.7**	**7.4**
27	7.4	6.9	9.6	7.4	1.1	1.3	2.6	**6.5**	**7.2**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	2.8	2.6	2.7	2.8	6.7	4.8	9.0	**3.4**	**3.2**
47	1.7	1.9	1.5	1.7	6.9	4.5	6.9	**2.4**	**2.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	2.9	4.2	1.0	4.0	7.8	1.2	1	**2.9**	**2.9**
5B	1.7	1.6	3.0	3.0	8.5	7.5	6.3	**2.4**	**2.3**
5B_CCCT Dry	1.2	1.4	1.5	2.0	10.0	4.8	4.9	**1.7**	**1.4**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.7	4.0	6.4	6.0	5.1	4.9	4.5	**4.1**	**4.4**
9B	3.1	1.3	3.2	5.0	9.0	10.0	10.0	**3.6**	**3.7**
10B	6.7	7.4	5.7	8.0	5.7	5.3	6.8	**6.6**	**7.4**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.8	8.9	8.2	9.0	2.9	3.3	2.2	**7.8**	**8.9**
47B	5.3	4.7	1.2	7.0	8.1	1.0	7.4	**4.9**	**5.3**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.15 – \$35/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	1.8	1.6	1.0	1.8	10.0	10.0	10	**3.0**	**2.7**
2	1.0	1.7	1.3	1.0	7.1	3.9	2.1	**1.7**	**1.0**
3	2.8	3.1	6.7	2.8	2.7	2.0	2.1	**3.0**	**2.7**
5	1.0	1.1	1.6	1.0	7.5	5.2	4.6	**1.8**	**1.2**
8	1.0	1.4	4.3	1.0	5.7	5.1	7.6	**2.0**	**1.5**
9	1.2	1.0	1.8	1.2	7.5	5.9	5.8	**2.0**	**1.4**
10	1.9	2.1	3.8	1.9	6.2	5.5	8.9	**2.8**	**2.5**
11	3.3	1.8	7.1	3.3	2.6	2.2	2.9	**3.1**	**2.8**
14	5.3	5.0	9.7	5.3	1.7	1.4	1.3	**4.9**	**5.1**
17	2.5	1.9	6.6	2.5	4.4	4.2	6.6	**3.0**	**2.7**
18	2.5	2.7	5.4	2.5	4.8	4.4	7.8	**3.2**	**3.0**
19	3.0	2.8	6.4	3.0	4.6	4.4	7.1	**3.5**	**3.4**
20	5.3	4.0	8.0	5.3	2.0	2.1	4.3	**4.8**	**5.0**
22	7.0	6.8	10.0	7.0	1.0	1.0	1.0	**6.2**	**6.9**
24	7.2	8.0	9.6	7.2	1.1	1.1	1.5	**6.6**	**7.3**
25	4.2	3.6	8.0	4.2	3.0	3.1	5.1	**4.2**	**4.2**
26	7.0	7.5	9.6	7.0	1.6	1.5	3.4	**6.5**	**7.3**
27	7.1	6.7	9.6	7.1	1.1	1.3	2.6	**6.3**	**7.0**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.0	2.8	2.7	3.0	6.7	4.8	9.0	**3.5**	**3.3**
47	1.7	2.1	1.5	1.7	6.9	4.5	6.9	**2.4**	**2.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	3.9	5.5	1.0	6.0	7.9	1.2	1	**3.9**	**4.2**
5B	1.8	1.9	3.0	3.0	8.5	7.5	6.3	**2.5**	**2.4**
5B_CCCT Dry	1.3	1.4	1.5	2.0	10.0	4.8	4.9	**1.7**	**1.5**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.6	4.3	6.4	5.0	5.1	4.9	4.5	**4.0**	**4.3**
9B	3.4	1.6	3.2	4.0	9.0	10.0	10.0	**3.6**	**3.8**
10B	7.2	8.3	5.7	8.0	5.8	5.3	6.8	**7.0**	**7.9**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.8	9.0	8.2	9.0	2.9	3.3	2.2	**7.8**	**8.9**
47B	6.7	6.0	1.2	7.0	8.2	1.0	7.4	**5.7**	**6.4**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.16 – $40/ton Expected-value CO$_2$ Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	2.2	1.8	1.0	2.2	10.0	10.0	10	**3.2**	**2.8**
2	1.3	1.9	1.3	1.3	7.1	3.9	2.1	**1.9**	**1.0**
3	2.8	3.2	6.7	2.8	2.7	2.0	2.1	**3.0**	**2.5**
5	1.2	1.1	1.6	1.2	7.5	5.2	4.6	**1.9**	**1.0**
8	1.0	1.4	4.3	1.0	5.7	5.1	7.6	**2.0**	**1.2**
9	1.3	1.0	1.8	1.3	7.6	5.9	5.8	**2.1**	**1.3**
10	2.0	2.1	3.8	2.0	6.2	5.5	8.9	**2.8**	**2.3**
11	3.3	1.6	7.1	3.3	2.6	2.2	2.9	**3.0**	**2.6**
14	5.3	5.0	9.7	5.3	1.7	1.4	1.3	**4.9**	**5.0**
17	2.3	1.8	6.6	2.3	4.4	4.2	6.6	**2.8**	**2.3**
18	2.4	2.6	5.4	2.4	4.8	4.4	7.8	**3.1**	**2.6**
19	2.9	2.7	6.4	2.9	4.6	4.4	7.1	**3.4**	**3.0**
20	5.1	3.7	8.0	5.1	2.1	2.1	4.3	**4.6**	**4.6**
22	6.9	6.8	10.0	6.9	1.0	1.0	1.0	**6.2**	**6.7**
24	7.0	7.9	9.6	7.0	1.2	1.1	1.5	**6.5**	**7.1**
25	4.0	3.4	8.0	4.0	3.1	3.1	5.1	**4.0**	**3.9**
26	6.9	7.5	9.6	6.9	1.6	1.5	3.4	**6.4**	**7.1**
27	7.0	6.5	9.6	7.0	1.1	1.3	2.6	**6.2**	**6.7**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.3	3.0	2.7	3.3	6.8	4.8	9.0	**3.7**	**3.5**
47	2.0	2.2	1.5	2.0	7.0	4.5	6.9	**2.7**	**2.1**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	5.3	7.3	1.0	6.0	7.9	1.2	1	**4.9**	**5.4**
5B	2.0	2.4	3.0	3.0	8.5	7.5	6.3	**2.6**	**2.6**
5B_CCCT Dry	1.4	1.6	1.5	2.0	10.0	4.8	4.9	**1.8**	**1.6**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.4	4.7	6.4	4.0	5.1	4.9	4.5	**3.9**	**4.1**
9B	3.9	1.9	3.2	5.0	9.0	10.0	10.0	**4.1**	**4.4**
10B	7.8	9.5	5.7	7.0	5.8	5.3	6.8	**7.4**	**8.4**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.9	9.0	8.2	9.0	2.9	3.3	2.2	**7.8**	**9.0**
47B	8.5	7.8	1.2	8.0	8.3	1.0	7.4	**7.1**	**8.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.17 – $45/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	2.7	2.0	1.0	2.7	10.0	10.0	10	**3.6**	**3.2**
2	1.6	2.1	1.3	1.6	7.2	3.9	2.1	**2.1**	**1.2**
3	2.8	3.2	6.7	2.8	2.8	2.0	2.1	**3.0**	**2.4**
5	1.3	1.1	1.6	1.3	7.6	5.2	4.6	**2.0**	**1.0**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**2.0**	**1.1**
9	1.5	1.0	1.8	1.5	7.6	5.9	5.8	**2.2**	**1.3**
10	2.1	2.1	3.8	2.1	6.2	5.5	8.9	**2.9**	**2.2**
11	3.3	1.4	7.1	3.3	2.7	2.2	2.9	**3.0**	**2.4**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.9**	**4.9**
17	2.2	1.5	6.6	2.2	4.5	4.2	6.6	**2.7**	**2.0**
18	2.3	2.5	5.4	2.3	4.9	4.4	7.8	**3.0**	**2.4**
19	2.8	2.6	6.4	2.8	4.7	4.4	7.1	**3.3**	**2.8**
20	4.9	3.4	8.0	4.9	2.1	2.1	4.3	**4.4**	**4.3**
22	6.9	6.7	10.0	6.9	1.1	1.0	1.0	**6.1**	**6.6**
24	6.8	7.8	9.6	6.8	1.2	1.1	1.5	**6.3**	**6.9**
25	3.8	3.3	8.0	3.8	3.1	3.1	5.1	**3.9**	**3.6**
26	6.8	7.4	9.6	6.8	1.6	1.5	3.4	**6.4**	**6.9**
27	6.8	6.2	9.6	6.8	1.1	1.3	2.6	**6.1**	**6.5**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.7	3.2	2.7	3.7	6.9	4.8	9.0	**4.1**	**3.8**
47	2.4	2.4	1.5	2.4	7.1	4.5	6.9	**2.9**	**2.3**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	6.5	8.9	1.0	6.0	8.0	1.2	1	**5.8**	**6.7**
5B	2.0	2.7	3.0	3.0	8.5	7.5	6.3	**2.7**	**2.8**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.8**	**1.7**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	2.9	4.8	6.4	4.0	5.2	4.9	4.5	**3.7**	**4.0**
9B	4.2	2.3	3.2	5.0	9.0	10.0	10.0	**4.3**	**4.8**
10B	7.8	10.0	5.7	7.0	5.8	5.3	6.8	**7.5**	**8.9**
17B	8.8	8.9	10.0	9.0	1.0	1.1	2.2	**7.8**	**9.3**
18B	7.9	8.1	8.2	8.0	2.9	3.3	2.2	**7.1**	**8.4**
47B	10.0	9.2	1.2	10.0	8.3	1.0	7.4	**8.3**	**10.0**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

Table B.18 – \$50/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	3.2	2.3	1.0	3.2	10.0	10.0	10	**3.9**	**3.6**
2	2.0	2.3	1.3	2.0	7.2	3.9	2.1	**2.4**	**1.5**
3	2.8	3.3	6.7	2.8	2.9	2.0	2.1	**3.0**	**2.4**
5	1.5	1.1	1.6	1.5	7.6	5.2	4.6	**2.1**	**1.1**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**2.0**	**1.0**
9	1.7	1.0	1.8	1.7	7.6	5.9	5.8	**2.3**	**1.4**
10	2.2	2.1	3.8	2.2	6.3	5.5	8.9	**2.9**	**2.3**
11	3.2	1.3	7.1	3.2	2.8	2.2	2.9	**2.9**	**2.3**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.9**	**4.9**
17	2.0	1.3	6.6	2.0	4.5	4.2	6.6	**2.6**	**1.8**
18	2.2	2.4	5.4	2.2	4.9	4.4	7.8	**2.9**	**2.3**
19	2.7	2.4	6.4	2.7	4.7	4.4	7.1	**3.2**	**2.6**
20	4.7	3.1	8.0	4.7	2.1	2.1	4.3	**4.2**	**4.0**
22	6.8	6.6	10.0	6.8	1.1	1.0	1.0	**6.1**	**6.5**
24	6.6	7.7	9.6	6.6	1.2	1.1	1.5	**6.2**	**6.7**
25	3.6	3.0	8.0	3.6	3.2	3.1	5.1	**3.7**	**3.3**
26	6.6	7.2	9.6	6.6	1.7	1.5	3.4	**6.2**	**6.7**
27	6.6	6.0	9.6	6.6	1.1	1.3	2.6	**5.9**	**6.2**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	4.2	3.5	2.7	4.2	6.9	4.8	9.0	**4.4**	**4.2**
47	2.8	2.7	1.5	2.8	7.1	4.5	6.9	**3.2**	**2.6**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	6.8	9.9	1.0	9.0	8.0	1.2	1	**6.5**	**7.6**
5B	1.9	3.0	3.0	3.0	8.5	7.5	6.3	**2.7**	**2.8**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.9**	**1.7**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	2.2	4.5	6.4	4.0	5.2	4.9	4.5	**3.3**	**3.4**
9B	4.0	2.5	3.2	5.0	9.0	10.0	10.0	**4.2**	**4.6**
10B	6.7	9.7	5.7	8.0	5.9	5.3	6.8	**7.1**	**8.2**
17B	6.4	6.9	10.0	7.0	1.0	1.1	2.2	**6.0**	**6.9**
18B	5.9	6.4	8.2	6.0	2.9	3.3	2.2	**5.5**	**6.2**
47B	10.0	10.0	1.2	10.0	8.4	1.0	7.4	**8.5**	**10.0**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

Table B.19 – $55/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	3.8	2.6	1.0	3.8	10.0	10.0	10	**4.4**	**4.2**
2	2.4	2.6	1.3	2.4	7.3	3.9	2.1	**2.7**	**1.9**
3	2.9	3.4	6.7	2.9	3.0	2.0	2.1	**3.1**	**2.4**
5	1.7	1.1	1.6	1.7	7.6	5.2	4.6	**2.2**	**1.3**
8	1.0	1.4	4.3	1.0	5.9	5.1	7.6	**2.0**	**1.0**
9	1.9	1.0	1.8	1.9	7.7	5.9	5.8	**2.4**	**1.5**
10	2.3	2.1	3.8	2.3	6.3	5.5	8.9	**3.0**	**2.4**
11	3.2	1.0	7.1	3.2	2.8	2.2	2.9	**2.9**	**2.2**
14	5.2	5.1	9.7	5.2	1.9	1.4	1.3	**4.9**	**4.9**
17	1.8	1.0	6.6	1.8	4.5	4.2	6.6	**2.4**	**1.5**
18	2.1	2.2	5.4	2.1	5.0	4.4	7.8	**2.8**	**2.1**
19	2.6	2.3	6.4	2.6	4.7	4.4	7.1	**3.1**	**2.5**
20	4.4	2.7	8.0	4.4	2.2	2.1	4.3	**4.0**	**3.7**
22	6.7	6.6	10.0	6.7	1.1	1.0	1.0	**6.0**	**6.4**
24	6.4	7.6	9.6	6.4	1.2	1.1	1.5	**6.0**	**6.4**
25	3.4	2.8	8.0	3.4	3.2	3.1	5.1	**3.6**	**3.1**
26	6.5	7.1	9.6	6.5	1.7	1.5	3.4	**6.1**	**6.5**
27	6.4	5.7	9.6	6.4	1.1	1.3	2.6	**5.7**	**6.0**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	4.8	3.8	2.7	4.8	7.0	4.8	9.0	**4.8**	**4.8**
47	3.2	2.9	1.5	3.2	7.2	4.5	6.9	**3.5**	**3.1**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	7.1	10.0	1.0	9.0	8.1	1.2	1	**6.7**	**7.8**
5B	1.8	3.0	3.0	4.0	8.5	7.5	6.3	**2.9**	**2.9**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.9**	**1.6**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	1.5	3.9	6.4	3.0	5.2	4.9	4.5	**2.7**	**2.7**
9B	3.8	2.6	3.2	5.0	9.0	10.0	10.0	**4.1**	**4.5**
10B	5.7	8.7	5.7	8.0	5.9	5.3	6.8	**6.4**	**7.4**
17B	4.3	4.7	10.0	7.0	1.0	1.1	2.2	**4.6**	**5.1**
18B	4.1	4.4	8.2	6.0	2.9	3.3	2.2	**4.3**	**4.8**
47B	10.0	9.9	1.2	10.0	8.5	1.0	7.4	**8.5**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.20 – $60/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	4.6	3.1	1.0	4.6	10.0	10.0	10	**4.9**	**4.9**
2	2.9	3.0	1.3	2.9	7.3	3.9	2.1	**3.1**	**2.4**
3	2.9	3.6	6.7	2.9	3.0	2.0	2.1	**3.2**	**2.5**
5	2.0	1.4	1.6	2.0	7.7	5.2	4.6	**2.4**	**1.5**
8	1.0	1.6	4.3	1.0	5.9	5.1	7.6	**2.1**	**1.0**
9	2.2	1.3	1.8	2.2	7.7	5.9	5.8	**2.6**	**1.8**
10	2.4	2.4	3.8	2.4	6.3	5.5	8.9	**3.1**	**2.5**
11	3.2	1.1	7.1	3.2	2.9	2.2	2.9	**2.9**	**2.1**
14	5.2	5.3	9.7	5.2	1.9	1.4	1.3	**4.9**	**4.9**
17	1.6	1.0	6.6	1.6	4.6	4.2	6.6	**2.3**	**1.3**
18	2.0	2.3	5.4	2.0	5.0	4.4	7.8	**2.8**	**2.0**
19	2.4	2.3	6.4	2.4	4.8	4.4	7.1	**3.0**	**2.3**
20	4.1	2.5	8.0	4.1	2.2	2.1	4.3	**3.8**	**3.4**
22	6.6	6.6	10.0	6.6	1.1	1.0	1.0	**5.9**	**6.3**
24	6.1	7.5	9.6	6.1	1.3	1.1	1.5	**5.9**	**6.2**
25	3.1	2.8	8.0	3.1	3.2	3.1	5.1	**3.4**	**2.8**
26	6.3	7.0	9.6	6.3	1.7	1.5	3.4	**6.0**	**6.3**
27	6.1	5.5	9.6	6.1	1.2	1.3	2.6	**5.5**	**5.7**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	5.4	4.3	2.7	5.4	7.0	4.8	9.0	**5.3**	**5.4**
47	3.8	3.4	1.5	3.8	7.2	4.5	6.9	**4.0**	**3.6**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	7.4	10.0	1.0	9.0	8.1	1.2	1	**6.8**	**7.9**
5B	1.8	3.1	3.0	4.0	8.5	7.5	6.3	**2.9**	**2.8**
5B_CCCT Dry	1.6	1.6	1.5	3.0	10.0	4.8	4.9	**2.0**	**1.7**
5B_CCCT Wet	1.1	1.0	1.5	2.0	9.8	4.6	4.7	**1.5**	**1.0**
8B	1.0	3.4	6.4	1.0	5.2	4.9	4.5	**2.1**	**1.7**
9B	3.7	2.7	3.2	7.0	9.0	10.0	10.0	**4.4**	**4.8**
10B	5.0	7.8	5.7	8.0	6.0	5.3	6.8	**5.9**	**6.7**
17B	2.7	2.8	10.0	5.0	1.0	1.1	2.2	**3.2**	**3.1**
18B	2.7	2.8	8.2	6.0	2.9	3.3	2.2	**3.4**	**3.4**
47B	10.0	9.8	1.2	10.0	8.5	1.0	7.4	**8.4**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.21 – \$65/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	5.4	3.7	1.0	5.4	10.0	10.0	10	**5.5**	**5.7**
2	3.5	3.6	1.3	3.5	7.4	3.9	2.1	**3.6**	**3.0**
3	2.9	3.9	6.7	2.9	3.1	2.0	2.1	**3.2**	**2.6**
5	2.3	1.7	1.6	2.3	7.7	5.2	4.6	**2.7**	**1.8**
8	1.0	1.9	4.3	1.0	6.0	5.1	7.6	**2.1**	**1.0**
9	2.5	1.6	1.8	2.5	7.7	5.9	5.8	**2.9**	**2.1**
10	2.5	2.7	3.8	2.5	6.3	5.5	8.9	**3.3**	**2.6**
11	3.1	1.1	7.1	3.1	2.9	2.2	2.9	**2.8**	**2.0**
14	5.2	5.5	9.7	5.2	2.0	1.4	1.3	**4.9**	**4.9**
17	1.3	1.0	6.6	1.3	4.6	4.2	6.6	**2.1**	**1.0**
18	1.8	2.4	5.4	1.8	5.0	4.4	7.8	**2.7**	**1.8**
19	2.2	2.4	6.4	2.2	4.8	4.4	7.1	**2.9**	**2.2**
20	3.8	2.3	8.0	3.8	2.2	2.1	4.3	**3.6**	**3.0**
22	6.5	6.6	10.0	6.5	1.1	1.0	1.0	**5.9**	**6.1**
24	5.8	7.5	9.6	5.8	1.3	1.1	1.5	**5.7**	**5.9**
25	2.8	2.7	8.0	2.8	3.3	3.1	5.1	**3.2**	**2.5**
26	6.1	7.0	9.6	6.1	1.7	1.5	3.4	**5.8**	**6.1**
27	5.8	5.3	9.6	5.8	1.2	1.3	2.6	**5.3**	**5.3**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	6.2	4.9	2.7	6.2	7.1	4.8	9.0	**5.8**	**6.1**
47	4.4	4.0	1.5	4.4	7.3	4.5	6.9	**4.5**	**4.2**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	7.7	10.0	1.0	9.0	8.2	1.2	1	**7.0**	**8.0**
5B	2.2	3.1	3.0	6.0	8.5	7.5	6.3	**3.3**	**3.2**
5B_CCCT Dry	2.0	1.6	1.5	5.0	10.0	4.8	4.9	**2.5**	**2.1**
5B_CCCT Wet	1.6	1.0	1.5	2.0	9.8	4.6	4.7	**1.7**	**1.0**
8B	1.0	3.0	6.4	1.0	5.2	4.9	4.5	**2.0**	**1.3**
9B	3.9	2.7	3.2	7.0	9.0	10.0	10.0	**4.5**	**4.7**
10B	4.6	7.1	5.7	8.0	6.0	5.3	6.8	**5.6**	**6.2**
17B	1.6	1.3	10.0	3.0	1.0	1.1	2.2	**2.1**	**1.5**
18B	1.9	1.4	8.2	4.0	2.9	3.3	2.2	**2.4**	**1.9**
47B	10.0	9.7	1.2	10.0	8.6	1.0	7.4	**8.4**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.22 – $70/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	6.4	4.4	1.0	6.4	10.0	10.0	10	**6.3**	**6.8**
2	4.3	4.2	1.3	4.3	7.4	3.9	2.1	**4.1**	**4.0**
3	3.0	4.3	6.7	3.0	3.2	2.0	2.1	**3.3**	**2.9**
5	2.6	2.0	1.6	2.6	7.7	5.2	4.6	**2.9**	**2.4**
8	1.0	2.2	4.3	1.0	6.0	5.1	7.6	**2.2**	**1.4**
9	2.9	1.9	1.8	2.9	7.8	5.9	5.8	**3.2**	**2.7**
10	2.7	3.1	3.8	2.7	6.4	5.5	8.9	**3.5**	**3.1**
11	3.0	1.2	7.1	3.0	3.0	2.2	2.9	**2.8**	**2.2**
14	5.2	5.8	9.7	5.2	2.0	1.4	1.3	**5.0**	**5.1**
17	1.0	1.0	6.6	1.0	4.7	4.2	6.6	**1.9**	**1.0**
18	1.6	2.5	5.4	1.6	5.1	4.4	7.8	**2.6**	**1.9**
19	2.0	2.4	6.4	2.0	4.8	4.4	7.1	**2.8**	**2.2**
20	3.4	2.1	8.0	3.4	2.2	2.1	4.3	**3.3**	**2.8**
22	6.3	6.6	10.0	6.3	1.2	1.0	1.0	**5.8**	**6.1**
24	5.4	7.4	9.6	5.4	1.3	1.1	1.5	**5.4**	**5.7**
25	2.4	2.7	8.0	2.4	3.3	3.1	5.1	**2.9**	**2.4**
26	5.8	6.9	9.6	5.8	1.7	1.5	3.4	**5.7**	**6.0**
27	5.4	5.0	9.6	5.4	1.2	1.3	2.6	**5.0**	**5.1**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	7.0	5.5	2.7	7.0	7.1	4.8	9.0	**6.5**	**7.1**
47	5.2	4.6	1.5	5.2	7.3	4.5	6.9	**5.0**	**5.1**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	8.0	10.0	1.0	9.0	8.2	1.2	1	**7.1**	**8.3**
5B	2.7	3.8	3.0	6.0	8.5	7.5	6.3	**3.7**	**3.9**
5B_CCCT Dry	2.6	2.5	1.5	5.0	10.0	4.8	4.9	**3.0**	**2.9**
5B_CCCT Wet	2.1	1.9	1.5	4.0	9.8	4.6	4.7	**2.5**	**2.3**
8B	1.2	3.4	6.4	2.0	5.2	4.9	4.5	**2.3**	**2.1**
9B	4.2	3.6	3.2	7.0	9.0	10.0	10.0	**4.8**	**5.3**
10B	4.4	6.8	5.7	8.0	6.0	5.3	6.8	**5.5**	**6.2**
17B	1.0	1.0	10.0	1.0	1.0	1.1	2.2	**1.5**	**1.0**
18B	1.4	1.3	8.2	3.0	2.9	3.3	2.2	**2.0**	**1.7**
47B	10.0	9.6	1.2	10.0	8.7	1.0	7.4	**8.4**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.23 – Alternate Performance Ranking Scheme Including the Upper-Tail Mean PVRR

	Cost Measures			Risk Measures						
Case	**Mean PVRR**	**Rate Impact**	**Capital Cost**	**Upper-Tail Mean PVRR**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	6.0	8.9	1.0	6.0	6.0	8.0	1.2	1	**5.5**	**6.2**
5B	3.0	2.7	3.0	5.0	3.0	8.5	7.5	6.3	**3.6**	**2.3**
5B_CCCT Dry	2.0	1.7	1.5	10.0	2.0	10.0	4.8	4.9	**3.7**	**2.5**
5B_CCCT Wet	1.0	1.0	1.5	9.0	1.0	9.8	4.6	4.7	**2.9**	**1.0**
8B	4.0	4.8	6.4	3.0	4.0	5.2	4.9	4.5	**3.9**	**3.0**
9B	5.0	2.3	3.2	8.0	5.0	9.0	10.0	10.0	**5.2**	**5.5**
10B	7.0	10.0	5.7	4.0	7.0	5.8	5.3	6.8	**6.5**	**8.1**
17B	10.0	8.9	10.0	1.0	9.0	1.0	1.1	2.2	**6.5**	**8.1**
18B	8.0	8.1	8.2	2.0	8.0	2.9	3.3	2.2	**5.9**	**6.9**
47B	9.0	9.2	1.2	7.0	10.0	8.3	1.0	7.4	**7.5**	**10.0**

Importance Weights	**25%**	**20%**	**5%**	**20%**	**15%**	**5%**	**5%**	**5%**

PORTFOLIO PVRR COST COMPONENT COMPARISON

Tables B.24 and B.25 show the breakdown of each portfolio’s stochastic mean PVRR by variable and fixed cost components. These costs reflect the $45/ton CO_2 cost adder scenario. Table B.23 reports the cost component breakdown for the core case risk analysis portfolios, and table B.24 reports the cost component breakdown for the sensitivity cases.

Table B.26 reports the cost component breakdown for the “B-Series” cases.

Table B.24 – Core Case: Portfolio PVRR Cost Components ($45 CO2 - Tax Strategy)

Cost Component ($ 000)	**Case 01**	**Case 02**	**Case 03**	**Case 05**	**Case 08**	**Case 09**	**Case 10**
Variable Cost							
Total Fuel Cost	16,125,130	15,543,063	13,580,402	15,176,188	14,191,867	15,221,938	14,365,405
Variable O&M Cost	1,354,361	1,313,445	1,178,315	1,299,295	1,222,685	1,301,513	1,231,410
Total Emission Cost	16,572,039	16,423,972	14,513,519	15,372,854	14,691,301	15,402,030	14,814,449
Long Term Contracts and Front Office Transactions	7,683,311	7,645,536	6,218,678	8,279,365	8,978,705	7,043,480	7,898,602
DSM	1,960,939	2,698,475	3,183,577	2,731,677	3,015,434	2,727,382	2,982,268
Spot Market Balancing							
Sales	(11,241,728)	(12,148,264)	(12,685,112)	(12,257,235)	(13,089,333)	(11,693,493)	(12,469,007)
Purchases	5,242,221	4,484,667	3,865,500	4,376,068	3,714,988	4,919,231	4,438,725
Energy Not Served	260,803	160,944	129,235	180,780	184,495	192,675	192,339
Dump Power	(11,314)	(9,874)	(9,475)	(10,424)	(12,366)	(10,539)	(11,477)
Reserve Deficiency	105,557	57,384	42,426	70,640	73,920	84,875	77,276
Total Variable Net Power Costs	**38,051,318**	**36,169,346**	**30,017,065**	**35,219,208**	**32,971,694**	**35,189,092**	**33,519,990**
Real Levelized Fixed Costs	**1,841,501**	**3,372,843**	**10,727,798**	**4,070,089**	**6,272,174**	**4,209,077**	**6,351,579**
Total PVRR	**39,892,819**	**39,542,190**	**40,744,863**	**39,289,296**	**39,243,869**	**39,398,169**	**39,871,569**

Table B.24– *continued*

Cost Component ($ 000)	Case 11	Case 14	Case 17	Case 18	Case 19	Case 20	Case 22
Variable Cost							
Total Fuel Cost	13,411,665	12,979,334	13,625,227	13,894,512	13,812,607	12,774,851	12,558,146
Variable O&M Cost	1,164,587	1,174,538	1,204,222	1,220,845	1,213,726	1,143,695	1,126,059
Total Emission Cost	14,159,325	13,634,228	13,469,668	13,714,767	13,595,382	12,647,703	12,781,992
Long Term Contracts and Front Office Transactions	5,631,083	6,175,357	8,669,522	7,235,524	7,133,223	5,769,274	6,241,471
DSM	3,254,961	3,365,567	3,186,054	3,023,493	3,133,315	3,287,687	3,483,403
Spot Market Balancing							
Sales	(12,613,055)	(13,377,546)	(13,388,006)	(12,487,968)	(12,604,973)	(12,725,027)	(13,660,143)
Purchases	4,057,005	3,475,485	3,546,102	4,357,831	4,236,310	3,868,019	3,281,495
Energy Not Served	136,344	118,697	168,279	173,946	173,290	136,891	113,066
Dump Power	(14,693)	(11,743)	(21,406)	(17,158)	(20,959)	(29,967)	(17,258)
Reserve Deficiency	60,344	38,241	63,344	68,008	72,674	54,843	31,939
Total Variable Net Power Costs	**29,247,566**	**27,572,157**	**30,523,005**	**31,183,800**	**30,744,594**	**26,927,968**	**25,940,171**
Real Levelized Fixed Costs	**11,787,530**	**14,908,880**	**9,610,984**	**9,000,946**	**9,768,684**	**15,198,946**	**17,635,612**
Total PVRR	**41,035,097**	**42,481,038**	**40,133,989**	**40,184,746**	**40,513,279**	**42,126,914**	**43,575,783**

Table B.24 – *continued*

Cost Component ($ 000)	**Case 24**	**Case 25**	**Case 26**	**Case 27**	**Case 29**	**Case 46**	**Case 47**
Variable Cost							
Total Fuel Cost	12,231,023	13,129,485	12,576,599	12,220,360	12,238,723	15,333,331	15,396,709
Variable O&M Cost	1,099,133	1,168,243	1,121,716	1,098,935	1,132,357	1,298,792	1,301,473
Total Emission Cost	12,068,839	12,932,754	12,352,056	12,110,138	12,078,673	16,165,517	16,207,316
Long Term Contracts and Front Office Transactions	7,533,865	6,540,377	6,088,802	6,300,186	7,129,496	7,609,719	7,589,434
DSM	3,342,009	3,246,369	3,287,127	3,464,753	3,657,217	2,726,744	2,730,469
Spot Market Balancing							
Sales	(13,956,020)	(12,887,979)	(12,913,620)	(13,319,931)	(14,229,404)	(12,211,221)	(12,082,775)
Purchases	3,073,137	3,972,608	3,766,984	3,499,968	3,110,387	4,398,733	4,544,666
Energy Not Served	117,336	150,747	129,145	122,715	117,018	185,993	176,566
Dump Power	(27,096)	(28,268)	(25,987)	(29,421)	(24,641)	(10,206)	(10,145)
Reserve Deficiency	35,439	62,418	47,949	35,916	44,753	57,125	56,300
Total Variable Net Power Costs	**25,517,664**	**28,286,755**	**26,430,769**	**25,503,619**	**25,254,580**	**35,554,528**	**35,910,014**
Real Levelized Fixed Costs	**17,978,326**	**13,029,825**	**16,986,145**	**17,973,594**	**20,371,851**	**5,420,363**	**4,148,102**
Total PVRR	**43,495,990**	**41,316,580**	**43,416,914**	**43,477,213**	**45,626,430**	**40,974,891**	**40,058,117**

Table B.25 – Sensitivity Case: Portfolio PVRR Cost Components ($45 CO2 - Tax Strategy)

Cost Component ($ 000)	Case 04	Case 06	Case 07	Case 12	Case 13	Case 15	Case 16
Variable Cost							
Total Fuel Cost	15,884,444	15,730,813	14,991,433	14,562,408	13,537,752	11,929,242	14,206,320
Variable O&M Cost	1,338,612	1,351,623	1,271,070	1,237,469	1,170,671	1,100,516	1,236,954
Total Emission Cost	16,314,474	14,875,608	15,395,249	14,596,363	14,366,370	12,335,026	13,950,925
Long Term Contracts and Front Office Transactions	4,911,551	9,196,257	4,592,404	9,648,455	3,658,159	8,929,535	3,960,513
DSM	2,650,272	3,053,232	2,846,765	3,282,294	3,280,373	3,665,971	3,082,590
Spot Market Balancing							
Sales	(9,956,467)	(14,245,612)	(10,460,139)	(14,938,838)	(11,525,586)	(15,599,583)	(10,639,066)
Purchases	6,301,302	3,473,008	5,757,713	3,023,499	4,690,969	2,524,691	5,448,327
Energy Not Served	372,221	65,081	293,326	63,507	158,050	52,897	229,603
Dump Power	(11,262)	(10,881)	(11,158)	(12,168)	(11,069)	(15,063)	(18,523)
Reserve Deficiency	219,811	20,916	169,146	24,454	78,046	11,559	134,823
Total Variable Net Power Costs	**38,024,959**	**33,510,045**	**34,845,809**	**31,487,443**	**29,403,735**	**24,934,790**	**31,592,465**
Real Levelized Fixed Costs	**2,244,634**	**6,124,658**	**5,031,161**	**8,539,849**	**12,635,909**	**18,958,532**	**9,061,822**
Total PVRR	**40,269,592**	**39,634,703**	**39,876,970**	**40,027,293**	**42,039,643**	**43,893,322**	**40,654,287**

Table B.25 – *continued*

Cost Component ($ 000)	Case 21	Case 23	Case 28	Case 33	Case 41	Case 42	Case 43
Variable Cost							
Total Fuel Cost	13,007,111	12,578,685	12,742,452	12,501,704	14,418,506	13,740,869	12,159,435
Variable O&M Cost	1,160,870	1,120,171	1,138,737	1,114,443	1,241,622	1,215,560	1,094,393
Total Emission Cost	12,949,483	12,374,787	12,665,072	12,753,252	14,751,942	13,455,115	12,009,121
Long Term Contracts and Front Office Transactions	3,998,178	4,279,134	4,359,863	8,120,875	9,650,090	9,330,643	8,332,267
DSM	3,354,757	3,292,442	3,350,267	3,703,080	3,019,019	3,180,545	3,443,037
Spot Market Balancing							
Sales	(11,835,936)	(11,941,781)	(12,112,865)	(15,734,889)	(13,482,889)	(13,854,964)	(14,423,822)
Purchases	4,420,951	4,234,304	4,207,497	2,781,782	3,514,149	3,284,808	2,851,243
Energy Not Served	150,089	136,396	140,469	47,920	152,058	130,139	112,439
Dump Power	(16,975)	(23,563)	(21,984)	(24,885)	(10,982)	(19,997)	(27,081)
Reserve Deficiency	73,946	61,138	65,057	15,831	63,886	52,524	32,499
Total Variable Net Power Costs	**27,262,475**	**26,111,711**	**26,534,563**	**25,279,114**	**33,317,402**	**30,515,242**	**25,583,531**
Real Levelized Fixed Costs	**15,775,521**	**17,512,414**	**17,067,782**	**21,006,239**	**6,247,502**	**9,651,213**	**17,902,669**
Total PVRR	**43,037,996**	**43,624,125**	**43,602,345**	**46,285,353**	**39,564,904**	**40,166,454**	**43,486,200**

Table B.26 – B-Series Cases: Portfolio PVRR Cost Components ($45 CO2 - Tax Strategy)

Cost Component ($ 000)	Case 02b	Case 05b	Case 05b CCCT Dry	Case 05b CCCT Wet	Case 08b
Variable Cost					
Total Fuel Cost	14,981,715	14,323,649	15,157,854	15,208,477	13,688,145
Variable O&M Cost	1,287,418	1,253,185	1,312,868	1,310,220	1,204,987
Total Emission Cost	16,485,129	15,494,162	15,525,754	15,497,737	14,892,730
Long Term Contracts and Front Office Transactions	7,463,381	7,915,814	7,771,960	7,799,715	8,819,100
DSM	2,916,885	2,958,280	2,751,344	2,746,235	3,255,097
Spot Market Balancing					
Sales	(12,826,888)	(12,809,283)	(12,871,265)	(12,946,171)	(13,662,496)
Purchases	4,832,059	4,745,567	4,640,620	4,585,533	4,082,885
Energy Not Served	171,787	201,496	189,697	187,039	188,764
Dump Power	(10,619)	(10,784)	(9,671)	(9,597)	(11,626)
Reserve Deficiency	76,487	104,752	82,362	80,930	88,925
Total Variable Net Power Costs	**35,377,354**	**34,176,835**	**34,551,522**	**34,460,119**	**32,546,512**
Real Levelized Fixed Costs	**4,684,686**	**5,275,240**	**4,817,015**	**4,854,695**	**7,126,759**
Total PVRR	**40,062,040**	**39,452,075**	**39,368,538**	**39,314,814**	**39,673,271**

Table B.26– *continued*

Cost Component ($ 000)	**Case 09b**	**Case 10b**	**Case 17b**	**Case 18b**	**Case 47b**
Variable Cost					
Total Fuel Cost	14,391,506	13,782,388	13,145,794	13,439,719	15,038,431
Variable O&M Cost	1,256,859	1,207,522	1,186,321	1,205,510	1,299,997
Total Emission Cost	15,555,068	14,920,273	13,645,023	13,938,418	16,354,069
Long Term Contracts and Front Office Transactions	7,300,096	8,078,996	8,712,260	7,478,893	7,581,800
DSM	2,948,350	3,230,797	3,390,861	3,259,964	2,863,945
Spot Market Balancing					
Sales	(12,421,787)	(13,137,936)	(14,185,362)	(13,217,280)	(12,797,023)
Purchases	5,035,985	4,610,885	3,790,156	4,544,153	4,773,896
Energy Not Served	217,010	191,297	166,406	180,757	177,657
Dump Power	(10,960)	(10,849)	(21,524)	(18,375)	(9,913)
Reserve Deficiency	114,217	89,352	72,750	79,612	54,371
Total Variable Net Power Costs	**34,386,343**	**32,962,725**	**29,902,685**	**30,891,372**	**35,337,229**
Real Levelized Fixed Costs	**5,338,215**	**7,298,315**	**10,636,072**	**9,461,888**	**5,169,437**
Total PVRR	**39,724,558**	**40,261,040**	**40,538,757**	**40,353,260**	**40,506,666**

APPENDIX C – IRP REGULATORY COMPLIANCE

BACKGROUND

Least-cost planning (i.e., Integrated Resource Planning) guidelines were first imposed on regulated utilities by state commissions in the 1980s. Their purpose was to require utilities to consider all resource alternatives—including demand-side measures—on an equal comparative footing, when making resource planning decisions. Integrated resource planning has expanded since then to incorporate the consideration of risk, uncertainty, and environmental externality costs into the resource evaluation framework. Planning rules were also intended to require utilities to involve regulators and the general public in the planning process prior to making resource decisions.

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

This appendix provides a discussion on how the 2008 IRP complies with the various state commission IRP Standards and Guidelines, 2007 IRP acknowledgement requirements, and other commission decisions. Included at the end of this appendix are the following tables:

- Table C.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.[1]
- Table C.2 – Provides a description of how the 2007 IRP acknowledgement requirements and other commission requests were addressed.
- Table C.3 – Provides an explanation of how this plan addresses each of the items contained in the new Oregon IRP guidelines issued in January 2007.
- Table C.4 – Provides an explanation of how this plan addresses each of the items contained in the Utah Public Service Commission IRP Standard and Guidelines issued in June 1992.
- Table C.5 – Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Trade Commission IRP guidelines issued in January 2006.

GENERAL COMPLIANCE

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the state commissions. The preparation of the IRP is done in an open public process with consultation between all interested parties, including commissioners and commission staff, customers, and other

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[1] California and Wyoming requirements are not summarized in Table C.1. The Wyoming requirements are discussed in the chapter text. California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP.

stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, described in Volume 1, Chapter 2, as well as in Appendix E, fully complies with the IRP Standards and Guidelines.

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

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 7 and 8, meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of numerous risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western Interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described at a high level in Chapter 2 and in greater detail in Chapter 7.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 8.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 9). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. Appendix D provides a progress report that relates the 2007 IRP Action Plan with those provided in the 2007 IRP and 2007 IRP Update.

The 2008 IRP and the related Action Plan are filed with each commission with a request for prompt acknowledgement. Acknowledgement means that a commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgement is made. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets acknowledgement standards.

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

California

Subsection (i) of California Public Utilities Code, Section 454.5, states that utilities serving less than 500,000 customers in the state are exempt from filing an Integrated Resource Plan for California. PacifiCorp serves only 45,072 average customers in the most northern parts of the state. PacifiCorp filed for and received an exemption on July 10, 2003.

Idaho

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

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

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2007, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 6 and 7. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in IPUC Order No. 21249.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its new planning guidelines issued in January 2007 (Order No. 07-002). These guidelines supersede previous ones, and many codify analysis requirements outlined in the Commission's acknowledgement order for PacifiCorp's 2004 IRP.

The Commission's new IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), and resource acquisition (Guideline 13). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgement does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table C.3 provides considerable detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Utah Public Service Commission in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines”). Table C.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238), and the rule amendment issued on January 9, 2006 (WAC 480-100-238, Docket No. UE-030311). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that “relates the new plan to the previously filed plan.”

The rule amendment also now requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on February 21, 2006, and had a follow-up conference call with WUTC staff to make sure the work plan met staff expectations.

Finally, the rule amendment now requires PacifiCorp to provide an assessment of transmission system capability and reliability. This requirement was met in this IRP by modeling the company’s current transmission system along with both generation and transmission resource options as part of its resource portfolio analyses. These analyses used such reliability metrics as Loss of Load Probability and Energy Not Served to assess the impacts of different resource combinations on system reliability. The stochastic simulation and risk analysis section of Chapter 7 reports the reliability analysis results.

Wyoming

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

In 2009, Wyoming proposed a draft rule 253 for any utility serving Wyoming to file their Integrated Resource Plan with the commission. This rule is still under review and is open for public comment until April 27, 2009 and with a schedule public hearing on May 12, 2009.

> *Rule 253: Integrated Resource Planning.*
> *Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.*

Table C.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho
Source	Order 89-507 *Least-cost Planning for Resource Acquisitions*, April 20, 1989. Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation and low-income programs.
Frequency	Plans filed biennially. Interim reports on plan progress also required (informational filing only). Order 07-002 requires IRP filing within two years of its previous IRP acknowledgement order.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.
Commission response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgement order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP *acknowledged* if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.

Topic	Oregon	Utah	Washington	Idaho
Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. For the amended rules issued in January 2006, PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at “lowest reasonable” cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis.	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options;

Topic	Oregon	Utah	Washington	Idaho
	long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Identify acquisition strategies for action plan resources, assess advantages/disadvantages of resource ownership versus purchases, and identify benchmark resources considered for competitive bidding. • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Avoided cost filing required within 30 days of acknowledgement.	• Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders • DSM and supply side resources evaluated at “Total Resource Cost” rather than utility cost.	• An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability (Added per amended rules issued in January 2006). • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using “lowest reasonable cost” criteria. • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan.	• Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.

Table C.2 – Handling of 2007 IRP Acknowledgement and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
Idaho		
Acceptance of Filing, Case No. PAC-E-07-11, p. 9	Staff further recommends that the Company address modifications to its 2007 resource acquisition strategies on a state-by-state basis in the form of periodic updates to its 2007 IRP.	Stakeholder and Bidder meetings are held throughout the RFP process on a periodic basis.
Acceptance of Filing, Case No. PAC-E-07-11, p. 9	Staff also recommends that the Company investigate critical peak pricing programs to augment its existing time-of-use schedule. Staff considers the deployment of advanced metering to be an indispensable part of that investigation.	Critical Peak Pricing (CPP) programs (Class 3 DSM) are included as resource options for portfolio modeling. PacifiCorp developed a sensitivity portfolio with these resources and other price-response programs, and simulated it using its stochastic production cost model (Chapter 8). Class 3 DSM programs are addressed in Item 7 of the IRP action plan (Chapter 9).
Acceptance of Filing, Case No. PAC-E-07-11, p. 10	Given the increasing role of jurisdictional resource mandates in the planning process, Staff further recommends that future IRPs incorporate a section devoted to the impacts, if any, of state policies on the selection of preferred portfolios.	State RPS requirements are explicitly accounted for in resource portfolio modeling, and the company is in the process of implementing capacity expansion modeling enhancements to improve representative of jurisdiction-specific CO_2 and RPS rules. Please refer to Chapter 3 RPS discussion and Chapter 7 discussing the Alternative Scenarios. State environmental/energy policies are discussed in Chapters 3, and are addressed in the IRP action plan (Chapter 9)
PURPA QF Wind, ID PAC-E-07-07, p. 6	(PacifiCorp) shall hereafter file notice with the Commission of any changes to its wind integration charge as reflected in subsequent changes to its IRP.	PacifiCorp is preparing an update to its wind integration cost estimates. This updated information will be provided in the final IRP document to be filed with state commissions by May 29, 2009
PURPA QF Wind, ID PAC-E-07-07, p. 6	Expected wind integration cost information will be included in the Company s integrated resource planning (IRP) process in the same way that costs for other generating resources are included in the IRP.	See slide 2 from the December 2, 2008 Conference, showing the adoption of PGE's integration cost of \$11.75/MWh in 2008 dollars. This value was treated as a placeholder until the company completes its wind integration study
PURPA QF Wind, ID PAC-E-07-07, p. 7	Idaho wind developers will be notified as part of the public meeting process and can contribute their input at those meetings to discuss PacifiCorp s wind integration study and new data related to wind integration costs prior to the publishing of the Company s next (2009) IRP.	PacifiCorp has added several contacts for Idaho wind developers to the participant list. PacifiCorp held a wind integration cost technical conference on December 2, 2008.
Oregon		

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
Order No. 08-232, LC-42, p. 13	Staff also recommends further consideration of nuclear passive safety and pumped storage technologies in the next planning cycle.	PacifiCorp included advanced nuclear and pumped storage technologies as resource options in portfolio modeling. See Chapters 6 and 7.
Order No. 08-232, LC-42, p. 14	Addressing a requirement from the last planning cycle, the IRP includes a discussion of how various thermal resources affect wind integration costs. Staff recommends a more thorough discussion in the next resource plan.	See Appendix H for additional information on wind integration costs, to be provided when the IRP is filed May 29, 2009.
Order No. 08-232, LC-42, p. 15	Staff recommends the Company take a hard look at low market price scenarios in analyzing its resource choices. Such possible futures point out the risks of capital-intensive, base load resources.	PacifiCorp developed seven portfolios using low market price assumptions. See Chapter 7 for portfolio input assumptions.
Order No. 08-232, LC-42, p. 17	The IRP includes a cursory discussion of hedging. Staff recommends a more robust discussion of hedging in future resource plans. Commission agrees with staff…"[the] plan should include a more substantive discussion of hedging as specified by Guideline 1c.	See Chapter 9 for a discussion on Use of Physical and Financial Hedging for Electricity Price Risk.
Order No. 08-232, LC-42, p. 21	Staff recommends the Company model market purchases for the later years of the plan in order to consistently compare portfolios, and not inappropriately weight resource decisions in the distant future.	The 2008 IRP extends front office purchases to end of the simulation period (2028), and also specifies Growth Resources, available to the model after 2020, using forward market prices. See the section in Chapter 7, "Modeling Front Office Transactions and Growth Resources".
Order No. 08-232, LC-42, p. 26	We therefore support the agreed-upon modifications to Action Items 3 and 4 related to demand response resources. [Staff's concerns that the IRP may have underestimated the level of risk-adjusted, cost-effective demand response.]	See Chapter 6 on Resource Options and the results in Chapter 8.
Order No. 08-232, LC-42, p. 29	Pacific Power's next plan should further evaluate solar direct use and generating resources.	PacifiCorp complied with this recommendation. See Chapter 6 on the additional solar options included for portfolio development.
Order No. 08-232, LC-42, p. 36	4. In the next planning cycle, include IGCC plants with carbon capture and sequestration as a resource option for selection.	PacifiCorp included IGCC plants with CCS as resource options in all the portfolios modeled. See Chapter 6 for resource specifications and background information.
Order No. 08-232, LC-42, p. 36	5. In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.	In formulating market purchase options for the IRP models, the company lacked information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the company anticipated using bid information from the 2008 All-Source RFP to inform the development of

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
		intermediate-term market purchase resources for modeling purposes. The company received no intermediate-term market purchase bids; therefore, such resources could not be reasonably modeled for this IRP. (See Chapter 6, "Resource Options)
Order No. 08-232, LC-42, p. 36	6. For the 2007 IRP update and next planning cycle, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.	PacifiCorp designed a portfolio analysis to address this requirement, estimating a system-wide hard cap based on Oregon's HB 3543 emission reduction goals. The company corrected a deficiency with the analysis pointed out by OPUC staff (assigning an emission rate to market purchases). A description of this portfolio scenario ("case 40") is provided in Chapter 7; modeling results are provided in Chapter 8.
Order No. 08-232, LC-42, p. 36	7. For the next planning cycle, further develop with stakeholders use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.	See the sections in Chapter 8 discussing the LOLP and ENS modeling results. PacifiCorp will investigate functionality in the company's capacity expansion optimization model (System Optimizer) to apply an LOLP constraint. This activity is identified in Action Plan item no. 9, Planning Process Improvements.
Order No. 08-232, LC-42, p. 36	8. For the next planning cycle, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.	Forced early retirement is discussed in Chapter 9 under Managing Carbon Risk for Existing Plants. The option of retrofits is a resource option in the portfolio development process.
Order No. 08-232, LC-42, p. 36	9. Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emissions rates to short-term market transactions.	PacifiCorp is implementing System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. This activity is identified in Action Plan item no. 9, Planning Process Improvements. Development of this functionality was complicated and could not be completed in time for this IRP.
Order No. 08-232, LC-42, p. 37	1. For the 2007 IRP Update and next IRP, Pacific Power should model other renewable resources in addition to wind.	PacifiCorp included geothermal, biomass, solar, and hydrokinetic technologies as resource options in portfolio modeling. See Chapter 6 "Resource Options" and Chapter 7 "Modeling and Portfolio Evaluation Approach".
Order No. 08-232, LC-42, p. 37	2. For the next IRP, Pacific Power should rank portfolios based on the 95th Percentile and Upper-Tail PVRR risk metrics, and explain any inconsistencies between portfolios that rank highest	PacifiCorp reports the 95th Percentile and Upper-Tail PVRR metrics, along with a new measure called risk-adjusted PVRR, which was used for "2012 Base-load RFP" bid evaluation. The risk exposure measure was

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
	according to these measures and the Company's preferred portfolio.	dropped from the IRP. See Chapters 7 and 8 for descriptions of the risk measures and the portfolio ranking process, respectively. For portfolio ranking purposes, incorporation of the risk-adjusted PVRR in the preference scoring process addresses the requirement to reflect an upper-tail risk measure in portfolio ranking. However, Table B.23 in the Appendix volume shows an alternate ranking scheme where the upper-tail mean PVRR is included as a separate performance measure and given an importance weight nearly as large as the mean PVRR. This alternate ranking scheme is applied to the final 10 portfolios considered for preferred portfolio selection.
Order No. 08-232, LC-42, p. 37	3. For the next IRP, in response to concerns noted in this order, Pacific Power should further analyze and discuss the use of hedging, the level of short-term market purchases, projected load growth, modeling of resources to meet loads in the later years of the planning horizon, capital cost risks and assumed economic lives of coal plants, and the appropriate level of distributed generation.	• Hedging is addressed in Chapter 9. • PacifiCorp modeled market purchases based on several forward price futures (low, medium, high), and applying forward price curves developed at two points in time (See Chapter 7) • PacifiCorp modeled alternative load growth scenarios, and conducted portfolio analysis with two load forecasts developed in November 2008 and February 2009 • Resources, other than "growth resources", were allowed as model options for capacity expansion modeling (See Chapter 7) • PacifiCorp included 10-year capital costs as a portfolio performance evaluation measure, and developed a portfolio assuming a 20% increase in capital costs • Distributed generation resources (CHP and customer standby generation) were included as resource options in all portfolios modeled; the appropriate level of distributed generation is addressed in item no. 9 of the IRP action plan (Chapter 9)
Utah		
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company, in its next IRP process, to convene a public input meeting or technical workgroup session to review its approach to load forecast variation and to address the issue of load forecast error risk. This discussion must include the Committee's concerns	PacifiCorp held a load forecasting technical workshop on June 26, 2008. PacifiCorp attended two meetings with Utah parties to discuss various IRP and load forecasting issues (April 9 and May 14, 2008).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
	regarding use of 30-year normal temperatures for estimating peak demand, the number of years relied upon for developing stochastic parameters, and the role of planning reserve in managing the risks of forecast error.	
UT-07-2035-01, Report & Order, 2-6-08, p. 16	We direct the Company to continue to study the tradeoffs in planning to different planning reserve targets in future IRPs.	PacifiCorp's planning reserve margin analysis is summarized in Chapter 8.
UT-07-2035-01, Report & Order, 2-6-08, p. 17	We direct the Company to address [the issue of hydro capacity accounting] in its next IRP. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of [using the sustainable one-hour peak capacity method applied for the 2007 IRP]	This requirement is addressed in Chapter 5, Resource Needs Assessment, in the discussion on hydro resources.
UT-07-2035-01, Report & Order, 2-6-08, p. 23	We direct the Company to evaluate a full spectrum of supply-side and demand-side options which have different characteristics regarding size, dispatchability, expected cost, expected risks and lead time for construction. Modeling limitations will need to be addressed.	See Chapter 5 "Resource Options" for a description of the expanded number of resources included in portfolio modeling.
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company to host a public input meeting or technical workgroup to examine the reasonableness of the range of CO_2 adders for evaluating carbon regulation risk and risk mitigating resource strategies.	PacifiCorp held a public input meeting on modeling CO2 regulations (including specification of CO_2 adders) on June 26, 2008.
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company to consider the following three-step approach for developing its optimal portfolio: 1) Identify optimal portfolios for a relatively broad, and consistently applied, set of input assumptions; 2) subject all of these optimal portfolios to stochastic risk analysis and identify superior optimal portfolios with respect to the tradeoff between expected cost and risk exposure; 3) examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions.	See Chapter 7 "Modeling and Portfolio Evaluation Approach". This three-step approach was implemented for this IRP. The assessment of the value of step 3 is provided in Chapter 8.
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company, with public input, to develop a manageable set of potential future conditions, defined by a consistently applied set of input assumptions, and to develop a set of optimal portfolios	PacifiCorp has complied with this directive, and sought public input on the specification of input assumption scenarios at several public meeting during2008. The company initially developed 47 input assumption

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
	consistent with these sets of conditions.	scenarios ("cases"), developed resource portfolios optimized according to these scenarios, and subjected these portfolios to stochastic (Monte Carlo) production cost simulation. The company subsequently developed another 10 portfolios accounting for the removal of the Lake Side 2 combined-cycle plant as a planned resource in 2012, and using a consistent set of input cases to do so (the cases that yielded the original top-performing portfolios).
Washington		
Letter Order, UE-071062, p. 1	PacifiCorp does need to identify and better support significant changes it makes to base demand projections relative to previous IRPs. For example, no explanation is given as to why this IRP cut the expected demand growth in Washington by 50 percent.	See Chapter 5 "Resource Needs Assessment" and Chapter 8 for details on the load forecasts used. The company held several conference calls with public stakeholders describing the reason for load forecast adjustments having to do with recessionary impacts.
Letter Order, UE-071062, p. 1	The company should also improve the presentation of its two-year action plan.	The company has provided more detail in the IRP action plan, included an acquisition path analysis, and addressed several resource risk management topics not addressed in previous IRPs. See chapter 9.
Letter Order, UE-071062, p. 2	The Commission expects the company to use the Quantec estimates as the basis for its conservation program achievement objective rather than the one included in the IRP.	PacifiCorp developed energy efficiency supply curves based on the Cadmus Group (previously Quantec LLP) potentials information. See the discussion on supply curve development in Chapter 6. These supply curves served as resource options in the capacity expansion model.
Letter Order, UE-071062, p. 2	In its next plan, the company needs to better explain how it chose the transmission options to study, the process used to integrate the selection of both new generating resources and transmission expansions/enhancements, and how the transmission expansion will affect system operation, dispatch of resources and the flow of electricity throughout PacifiCorp's service territory.	PacifiCorp included a new "Transmission planning" chapter (Chapter 4), and included a separate transmission expansion action plan in Chapter 9.
Letter Order, UE-071062, p. 3	Therefore, we remind the company that any baseload resources put in service after June 30, 2008 to serve Washington customers, or any transmission that allows the output of such resources to reach Washington must comply with this state's statutory requirements.	PacifiCorp will follow state statutory requirements for delivery of energy to Washington.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
Letter Order, UE-071062, p. 3	What is unclear from this discussion is how PacifiCorp will determine when a revision in the planning margin is warranted. PacifiCorp needs to identify the metrics it will use or the processes it will monitor that could lead the company to alter its new planning margin.	PacifiCorp will investigate the use of a LOLP capacity constraint in its capacity expansion model to supplement the current planning reserve margin approach (See Chapter 9, action item no. 9). Development of a process to modify planning reserve margins has thus been put on hold. PacifiCorp is also monitoring WECC resource supply adequacy criteria for possible implications to the IRP.
Letter Order, UE-071062, p. 4	As part of its next plan, PacifiCorp should more thoroughly explain why its preferred portfolio provides greater benefits and/or is lower risk than the alternative portfolios.	See chapter 8 for an in-depth discussion on the merits and disadvantages of the preferred portfolio relative to other top-performing portfolios.
Letter Order, UE-071062, p. 4	PacifiCorp should derive avoided cost for transmission and distribution resources. These avoided costs will guide generators or suppliers as they determine if they can supply electricity below the company's avoided cost.	PacifiCorp incorporated a T&D investment deferral cost credit to demand-side management program costs.
Letter Order, UE-071062, p. 1	The action plan needs to provide much more specific information regarding the actual steps the company will take to complete the identified action items.	The IRP action plan provides more detail on procurement approaches for resources identified in the IRP preferred portfolio (See Table 9.2 in Chapter 9).
Wyoming		
The Wyoming Commission provided the following comment: *Pursuant to open meeting action taken on January 11, 2008, PacifiCorp d/b/a Rocky Mountain Power's 2007 Integrated Resource Plan (IRP) is hereby placed in the Commission's files. No further action will be taken and this docketed matter is closed.*		

Table C.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, distributed generation, energy storage, power purchases, thermal resources, and transmission. Chapters 6 and 7 document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, and selected by the model based on relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with the capacity expansion optimization model were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, life-times, and locations.
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Cadmus Group's supply curve data for representation of DSM and distributed generation resources, which was also based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Chapters 6 and 7.
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its after-tax WACC of 7.4 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	PacifiCorp fully complies with this requirement. Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation. See the stochastic modeling methodology section in Chapter 7.
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	PacifiCorp complied with this guideline by discussing resource risk mitigation in Chapter 9. Topics covered include: (1) managing carbon risk for existing plants, (2) the use of physical and financial hedging for

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
		electricity price risk, and (3) managing gas supply risk. Regulatory and financial management risks associated with a large capital expenditure program were highlighted in several areas throughout the IRP document.
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered, significantly expanding its representation of CO_2 cost risk and implementing a multi-measure portfolio preference ranking scheme. See Chapter 8 for the company's portfolio risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects consistent with past IRP practice.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PacifiCorp fully complies. Chapter 7 provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail PVRR (mean of highest five Monte Carlo iterations) and the 95th percentile stochastic PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on costs and risks of physical and financial hedging is provided in Chapter 9.
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 8 summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and expected state and federal energy policies in portfolio modeling. Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state resource policies. The IRP action plan chapter also presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes	PacifiCorp fully complies with this requirement. Chapter 2 provides an overview of the public process, while Appendix D documents the details on public

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	meetings held for the 2008 IRP.
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	Both IRP volumes provide non-confidential information the company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed a draft IRP document for external review on April 8, 2009.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	This Plan complies with this requirement.
3.b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PacifiCorp will adhere to this guideline.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	Not applicable
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	Not applicable
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable
3.f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may	Not applicable

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	request acknowledgment of changes in proposed actions identified in an update.	
3.g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1. Describes what actions the utility has taken to implement the plan; 2. Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3. Justifies any deviations from the acknowledged action plan.	Not applicable
Guideline 4. Plan Components (at a minimum, must include…)		
4.a	An explanation of how the utility met each of the substantive and procedural requirements	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	PacifiCorp developed low, medium, and high load growth forecasts for scenario analysis using the System Optimizer model for portfolio development. Stochastic variability of loads was also captured in the risk analysis. See Chapters 5 and 8, and Appendix E, for load forecast information. Chapter 8 also describes how loads are handled in the stochastic modeling.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested	This Plan complies with the requirement. See Chapter 5 for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies, as mentioned in Chapter 7.
4.d	For gas utilities only	Not applicable
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology	Chapter 6 identifies the resources included in this IRP, and provides their detailed cost and performance attributes. See Tables 6.2 through 6.10 for supply-side resources, and Tables 6.15 through 6.20 for demand-side resources.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs	In addition to incorporating a planning reserve margin for all portfolios evaluated, the company used several measures to evaluate relative portfolio supply reliability. These are described in Chapter 7 (Energy Not Served and Loss of Load Probability). PacifiCorp conducted a sensitivity study to determine the cost/risk tradeoff of different planning reserve margin levels. This study is documented in Chapter 8.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance	Chapter 7 describes the key assumptions and alternative scenarios used in this IRP.

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	costs) and alternative scenarios considered	
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system	This Plan documents the development and results of 57 portfolios designed to determine resource selection under a variety of input assumptions (Chapter 8).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 8 presents the stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 8 provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	PacifiCorp fully complies with this guideline. See the responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is presumed to have no inconsistencies.
	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapters 9 and 10 presents the 2008 IRP and transmission expansion action plans, respectively.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated proxy transmission resources on a comparable basis with respect to other proxy resources in this IRP. Fuel transportation costs were factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potentials study was completed in June 2007, and those results were incorporated into this plan.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See Chapter 6, "Class 2 DSM, Capacity Supply Curves"
6.c	To the extent that an outside party administers	See the response for 6.b above.

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 3 DSM) on a consistent basis with other resources in a portfolio study, and simulated the portfolio containing class 3 DSM resources using its stochastic production cost model (Chapter 8). Class 3 DSM programs are addressed in Item 7 of the IRP action plan in Chapter 9.
Guideline 8: Environmental Costs		
8	a. Base Case and Other Compliance Scenarios b. Testing Alternative Portfolios Against the Compliance Scenarios c. Trigger Point Analysis d. Oregon Compliance Portfolio	This IRP fully complies with the CO_2 compliance cost analysis requirements in Order No. 08-339. Performance results for CO_2 compliance scenario portfolios are reported in Chapter 8, as well as an Oregon compliance scenario (See Table C.2). Chapter 9 presents a discussion on "whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated" as required in Guideline 8c.
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	PacifiCorp continues to plan for load for direct access customers.
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2008 IRP conforms to the multi-state planning approach as stated in Chapter 2.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural	PacifiCorp fully complies with this guideline. See the response to 1.c.3.1 above. Chapter 8 describes the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost adder levels were used to inform the cost/risk tradeoff analysis. (Chapter 8).

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp evaluated several types of distribution generation, including combined heat and power and customer-owned standby generation. The results of these evaluations are documented in Chapter 8.
Guideline 13: Resource Acquisition		
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party 3. Identify any Benchmark Resources it plans to consider in competitive bidding	Chapter 9 outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 9. Company resources included in RFPs is addressed in the action plan (Table 9.2 and accompanying narrative).
13.b	For gas utilities only	Not applicable

Table C.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Utah Public Service Commission responsibility
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.	Not addressed; ratemaking occurs outside of the IRP process
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix D.
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Chapter 7 for a description of

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		the methodology employed, including how CO2 cost uncertainty is factored into the determination of relative portfolio performance.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp's capacity expansion optimization model. Also see the response to number 4.b.ii below.
7	Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	Consistent with the Utah rules, PacifiCorp determination of avoided costs will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Chapter 2 outlines the IRP/business plan alignment effort that was initiated in 2008 and will continue through 2009. Chapter 9 also describes recent IRP/business planning alignment activities associated with selection of a preferred portfolio.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	PacifiCorp implemented a highly transparent portfolio preference scoring methodology that incorporates numerous portfolio performance measures and considers CO_2 cost uncertainty in the portfolio ranking process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The Company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on May 30, 2007, and filed this IRP on May 29, 2009. PacifiCorp planned to file the IRP with all commissions on March 31 in each odd-numbered year. However, the Lake Side 2 decision prompted the company to revise the IRP accordingly, including conducting additional portfolio analysis.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix D.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
	parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2008 IRP are provided in Chapters 5 and 8, and Appendix E. Figures 7.3 and 7.4 in Chapter 7 show the range of forecasts used for capacity expansion modeling. Figures 7.22 through 7.26 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	Price risk associated with market sales is captured in the company's stochastic simulation results. Current off-system sales agreements are included in the IRP models.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Chapter 5 documents how demographic and price factors are used in PacifiCorp's new load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model.
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Chapter 6.
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Chapters 6 and 7 document how PacifiCorp developed and assessed these technologies.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves and distributed generation resources used for portfolio modeling explicitly incorporate estimated

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
	opportunities for customer participation.	rates of program and event participation. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Chapter 9.
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2009-2028)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Chapter 9. As mentioned in the chapter, the major preferred portfolio resources were evaluated for financial and rate impacts by the PacifiCorp Energy Finance Department in alignment with business planning protocols. A status report of the actions outlined in the previous action plan (2007 IRP update) is provided in Chapter 9 as well. The action plan (Table 9.2) also identifies actions anticipated to extend beyond the next two years, or occur after the next two years
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Chapter 9 includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, combinations of load growth and gas price futures, and procurement delays. The decision mechanism for pursuing the resource strategies is the outcome of the annual business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Chapter 7. The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Portfolios were evaluated using a range of CO_2 cost futures ● A discussion of environmental policy status and impacts on utility resource planning is provided in Chapter 3.
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Chapter 9, and covers the following topics: (1) managing carbon risk for existing plants, (2) the use of physical and financial hedging for electricity price risk, and (3) managing gas supply risk. Regulatory and financial management risks associated with a large capital expenditure program were highlighted in several areas throughout the IRP, and in relation to IRP and

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		business plan alignment. Resource capital cost uncertainty and technological risk is addressed in Chapter 6 (“Handling of Technology Improvement Trends and Cost Uncertainty”). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Chapter 9.
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Chapter 9 and the action plan (Table 9.2). In Chapter 8, PacifiCorp discusses how planning flexibility came into play for the timing of preferred portfolio resources such as wind.
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk. This trade-off analysis is documented in Chapter 8, and highlighted through the use of scatter plot graphs showing the relationship between expected and upper-tail stochastic PVRR.
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp estimated environmental externality costs for CO_2, NO_X, SO_2, and mercury with use of cost adders and assumptions regarding the form of compliance strategy (for example, cap-and-trade versus a per-ton tax for CO_2). For CO_2 externality costs, the company used scenarios with various cost adder levels to capture a reasonable range of cost impacts. These adders are described in Chapter 7.
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Chapter 6.
5	PacifiCorp will submit its IRP for public comment, review and acknowledgement.	PacifiCorp distributed the draft IRP document for public review and comment on April 8, 2009.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with	Not addressed; this is a post-filing activity.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
	comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.	
7	Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table C.5 – Washington Utilities and Trade Commission IRP Standard and Guidelines (WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the IRP work plan on January 18, 2008; at that time, the anticipated IRP filing date was January 20, 2009.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 2-3 of the Work Plan document for a summarization of resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See Figure 2, page 6 of the Work Plan document for the IRP schedule.
(4)	Integrated resource plan submitted within two years of previous plan.	The Commission issued an Order on December 11, 2008, under Docket no. UE-070117, granting the Company permission to file its IRP on March 31 of each odd numbered year. On March 26, 2009, the Commission granted PacifiCorp a temporary exemption from the March 31st deadline allowing the Company to file its 2008 integrated resource plan on May 29, 2009 (Docket No. UE-081475).
(5)	Commission issues notice of public hearing after company files plan for review.	Not applicable
(5)	Commission holds public hearing.	Not applicable
(2)(a)	Plan describes the mix of energy supply resources.	Chapter 8 describes the 2008 IRP preferred portfolio. For example, see Tables 8.44 and 8.45, as well as Figures 8.29 and 8.30.
(2)(a)	Plan describes conservation supply.	See Chapter 8, Tables 8.44 and 8.45, as well as Figures 8.29 and 8.30.
(2)(a)	Plan addresses supply in terms of current and future needs.	The 2008 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the Company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Chapter 5. For example, see Table 5.20 for PacifiCorp's capacity load and resource balance.
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Chapter 7.
(2)(b)	LRC analysis considers resource costs.	Chapter 6, Resource Options, provides detailed information on costs and other attributes for all resources analyzed for the IRP. For example, see Tables 6.2 through 6.10, 6.15 through 6.18, and 6.20.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. See the section entitled, "Monte Carlo Production Cost Simulation" in Chapter 7 for a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints,
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory costs, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Chapter 9 covers the following topics: (1) managing carbon risk for existing plants, (2) the use of physical and financial hedging for electricity price risk, and (3) managing gas supply risk. Regulatory and financial management risks associated

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		with a large capital expenditure program were highlighted in several areas throughout the IRP, and in relation to IRP and business plan alignment.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	The IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington, Oregon, California, and Utah. (See Chapter 7, "Representation and Modeling of Renewable Portfolio Standards", as well as Appendix A for RPS compliance reports developed for each resource portfolio assessed for the IRP). PacifiCorp also evaluated various CO_2 regulatory schemes, including a CO_2 tax, hard cap, and cap-and-trade. Future modeling enhancements are planned for improved representation of state-level resource regulations.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	A description of PacifiCorp's modeling of CO_2 cost risk is provided in Chapter 7, "Carbon Dioxide Compliance Strategy and Costs". Chapter 9 also discusses the implications of CO_2 cost uncertainty on resource acquisition plans. See Table 9.3.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Chapter 6, "Demand-side Resources".
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2008 IRP are provided in Chapters 5 and 8, and Appendix E. Figures 7.3 and 7.4 in Chapter 7 show the range of forecasts used for capacity expansion modeling. Figures 7.22 through 7.26 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Chapter 5, "Load Forecast", for a description of the load forecasting methodology.
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Chapter 5, "Load Forecast", for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp conducted a comprehensive system-wide demand-side management potential study in 2007, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. The DSM potential study is posted on PacifiCorp's Web page: http://www.pacificorp.com/Article/Article75535.html,

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		and has been provided to the WUTC on a CD.
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Chapter 5, Resource Needs Assessment ("Existing Resources").
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Chapters 6 and 7 document how PacifiCorp developed and assessed these technologies.
(3)(d)	Plan includes an assessment of transmission system capability and reliability (as allowed by current law).	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans (See the "Transmission System Representation" section in Chapter 7). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. The DSM potentials study considered improvements in conservation Distribution considered alternative transmission expansion options.
(3)(f)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Chapter 7. Portfolio evaluation covers a 20-year period (2009-2028). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.2, Chapter 9, for PacifiCorp's 2008 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	A status report on action plan implementation is provided in the "Progress on Previous Action Plan Items" section of Chapter 9.
(5)	Plan includes description of consultation with commission staff. (Description not required)	Chapter 2 includes a summary of the 2008 IRP public process, while Appendix D provides deals on specific meetings held with Commission staff and the general public.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
(5)	Plan includes description of completion of work plan. (Description not required)	Not applicable; the IRP schedule was modified to accommodate significant planning events. See the response to WAC 480-100-238(4).

APPENDIX D – PUBLIC INPUT PROCESS

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

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

The cornerstone of the public input process has been full-day public input meetings held approximately throughout the year-long plan development period. These meetings have been held jointly in two locations—Salt Lake City, Utah and Portland Oregon—using telephone and video conferencing technology.

A key change to the IRP public process occurring during the analysis preparation phase was the state stakeholder dialogue sessions from mid-March through April 2008. (For prior IRPs, the Company relied solely on general public meetings open to all participants.) These goal of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state, and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. This change in public process enhance interaction with stakeholders early on in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during general public meetings.

As far as agenda setting is concerned, PacifiCorp solicited recommendations from the state stakeholders in advance of the session, as well as allowing open time to ensure that participants had adequate time for dialogue. Some follow-up activities arising from the sessions were addressed in subsequent public meetings or another state meeting.

The 2008 public input meetings were augmented by a series of focused technical workshops to provide an opportunity to discuss complex topics for a multi-state utility in more detail.

PARTICIPANT LIST

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

Commissions

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

Intervenors

- Brigham Young University
- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- ECOS Consulting
- Energy Trust of Oregon
- Energy Strategies, LLC
- Health Environment Alliance of Utah (HEAL)
- Horizon Wind Energy
- Industrial Customers of Northwest Utilities
- Kennecott
- Mountain West Consulting, LLC
- Northwest Power and Conservation Council
- NW Energy Coalition
- Oregon Department of Energy
- Renewables Northwest Project
- Salt Lake City
- Salt Lake Community Action Program
- Southwest Energy Efficiency Project
- Sierra Club , Utah Chapter
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Air Quality
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Geological Survey
- Wasatch Clean Air Coalition
- Western Resource Advocates
- West Wind Wires
- Wyoming Industrial Energy Consumers
- Wyoming Office Of Consumer Advocacy

Others

- Portland General Electric (PGE)
- Avista Utilities
- Cadmus Group Inc. – Stuart McMenamin

- John Klingele (Washington Customer)

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

PUBLIC INPUT MEETINGS

PacifiCorp hosted five full-day public input meetings, two half day meetings, one conference call and six state meetings during the 2008. During the 2008 IRP process presentations and discussions covered various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings and the technical workshops.

General Meetings

February 29, 2008

- IRP Regulatory Compliance
- IRP Process Improvements
  - IRP/Business Plan Alignment Strategy
  - Public Process Changes
  - IRP Report Changes
- 2008 IRP Modeling Plan
- 2008 IRP Activity Timeline
- 10-Year Business Planning Process
- Resource Portfolio Development for the IRP Update/2008-2017 Business Plan
  - Load Forecast
- Demand-side Management Resources
- Capacity Load and Resource Balance
- Resource and Other Input Assumptions
- Resource Additions

May 22, 2008

- Update to the 2008 IRP Modeling Plan
- Case Definitions for Portfolio Development
- Natural Gas and Electricity Forecasts
- Resource Characterization
  - Supply side resources
  - DSM Supply Curves

May 23, 2008

- Proposed Oregon Public Utility Commission IRP guidelines on CO2 risk
- Range and timing of CO2 costs represented in the IRP
- Overview of the IPM (Integrated Planning Model) and usage for the IRP
- Overview of the EPRI study on CO2 policy impacts on western power markets

June 26, 2008

- Long-Term Load Forecast
    - Overview of the June 2008 Long Term Load Forecast
    - Total Company Profile
        - Forecast summary and Growth rate comparisons
        - Energy by State and Energy by Class
    - Rocky Mountain Power
        - Energy by Class
        - Utah, Wyoming, Idaho
    - Pacific Power
        - Energy by Class
        - Oregon, Washington, California
    - Risks to the Forecast
- Load and Resource Balance
- Update on portfolio development cases and modeling process

ITRON Agenda

- Modeling weather response using multi-part slopes and load research data
- Defining daily normal weather for weather normalization of energy
- Overview of the Statistically Adjusted End Use (SAE) approach
- Overview of sales models
- Overview of peak models and normal peak producing weather
- Overview of typical weather scenarios and hourly model forecasts

November 12, 2008 (Conference Call)

- IRP/ Business Plan Alignment
- IRP Development Status and Schedule
- Load Forecast

December 18, 2008

- Updated Schedule
- Updated Load Forecast
- Capacity Load and Resource Balance
- Portfolio Modeling Set-up
- Portfolio Development Results

Handout – Portfolio Development Results Package

January 7, 2009

(Repeat of 12/18/08 for Washington / Idaho participants that missed the earlier meeting)

- Updated Schedule
- Updated Load Forecast
- Capacity Load and Resource Balance
- Portfolio Modeling Set-up
- Portfolio Development Results

Handout – Portfolio Development Results Package

February 2, 2009
- Cover questions on portfolio development
- Stochastic simulation and top-performing portfolio selection approach
- Stochastic simulation results
    - Alternative capacity planning reserve margin analysis
- Portfolio ranking and preference scores
- Preferred portfolio selection
    - Scenario risk analysis

March 11, 2009 (Conference Call)
- IRP Schedule

March 19, 2009 (Conference Call) Utah Parties

- IRP Filing Extension

State Meetings

April 9, 2008 (Utah)
- DSM and enabling technologies
- Range of resource options
- Renewable energy resource analysis
    - Bramble (SB 202) renewables act and other renewable portfolio standards
    - Wind integration
    - Optimal wind amount under stochastic analysis
- Feedback on IRP/Business Plan Improvement Paper (distributed via email on 3/7/08)
- Load forecast

April 10, 2008 (Wyoming)
- DSM and enabling technologies
- Range of resource options
- Renewable energy resource analysis
- Feedback on IRP/Business Plan Improvement Paper (distributed via email on 3/7/08)
- Load forecast
- Planning reserve margin studies
- Regional capacity adequacy/market depth
- Environmental policy
    - CO2 costs/regulations
    - Other environmental externalities
- Other miscellaneous issues

April 21, 2008 (Oregon / California)

- DSM
- Range of supply-side resource options
- Feedback on the IRP/Business Plan improvement paper (distributed via email on 3/7/08)
- Impacts of the Oregon Commission 2008 IRP acknowledgment order
- Renewable energy resource analysis
- Planning reserve margin
- Environmental policy
  - Pending IRP environmental cost guideline no. 8 (UM 1302)
  - CO2 costs/regulations
- Load forecast
- Other miscellaneous issues

April 22, 2008 (Washington)

- DSM
- Range of supply-side resource options
- Feedback on the IRP/Business Plan improvement paper (originally distributed via email on 3/7/08)
- Renewable energy resource analysis and Renewable Portfolio Standards
- Planning reserve margin
- Environmental policy
- Load forecast
- Other miscellaneous issues

April 23, 2008 (Idaho)

- DSM
- Range of supply-side resource options
- Feedback on the IRP/Business Plan improvement paper (originally distributed via email on 3/7/08)
- Environmental/renewable regulatory resource constraints
- Planning reserve margin
- Load forecast
- Other miscellaneous issues

May 14, 2008 (Utah)

- Planning reserve margin studies
- Regional capacity adequacy/market depth
- Hydro capacity assumptions/sensitivity analysis
- Environmental policy
  - CO_2 costs/regulations
  - Other environmental externalities
- Other miscellaneous issues

PARKING LOT ISSUES

During the course of the public input meetings, certain concerns or questions needed additional follow-up from PacifiCorp. These questions or issues were taken off-line, addressed at a subsequent public input meeting or workshop, or assembled into a "parking lot" and responded to via a parking lot response document that is emailed to IRP participants. A number of public participants recommended that responses to individual information requests made through the IRP email "mailbox" or other means be made available to all IRP participants. PacifiCorp is investigating a process for doing do that is least burdensome to the company.

PUBLIC REVIEW OF IRP DRAFT DOCUMENT

PacifiCorp distributed the draft version of the IRP document on April 8, 2009, for public review, and requested written comments by May 6, 2009. Parties that submitted comments include:

- Renewable Northwest Project
- Oregon Department of Energy
- Public Utility Commission of Oregon Staff
- Washington Utilities and Transportation Commission Staff
- Utah Association of Energy Users (UAE)

In addition to these comments, a number of Utah parties submitted data requests prior to the filing of the final IRP document under the Utah commission's 2008 IRP acknowledgment docket (Docket No. 09-2035-01) established on April 27, 2009. These parties included the Utah Department of Public Utilities, the Utah Office of Consumer Services (formerly the Utah Committee of Consumer Services), Utah Association of Energy Users, and Utah Clean Energy.

Clarifications and information requested through the written comments and data requests were incorporated in the final version of the IRP to the extent that PacifiCorp had time to do so.

CONTACT INFORMATION

PacifiCorp's IRP internet website contains many of the documents and presentations that support the 2003, 2004, 2007 and 2008 Integrated Resource Plans. To access it, please visit the company's website at http://www.PacifiCorp.com , click on the menu "News & Info" and select "Integrated Resource Planning".

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

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APPENDIX E – STATE LOAD FORECAST

LOAD FORECAST STATE LEVEL SUMMARIES

This section provides state-level forecasted retail sales summaries. The tables below show retail sales values after the load reduction impacts of Class 2 DSM programs included in the 2008 IRP preferred portfolio are deducted. For purposes of the 2008 IRP this version of the data is known as "Post-DSM". Chapter 5 provides the forecast information for each state and the system as a whole by year for 2009 through 2018 before Class 2 DSM load reductions are applied.

State Summaries

Oregon

Table E.1 summarizes Oregon state forecasted sales growth by customer class.

Table E.1 – Forecasted Sales Growth in Oregon

Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	5,401	4,819	2,781	266	38	0	**13,304**
2010	5,439	4,836	2,816	265	37	0	**13,393**
2011	5,445	4,849	2,816	265	37	0	**13,413**
2012	5,476	4,872	2,853	265	37	0	**13,504**
2013	5,435	4,892	2,891	265	37	0	**13,520**
2014	5,413	4,924	2,915	265	37	0	**13,554**
2015	5,390	4,955	2,936	265	37	0	**13,583**
2016	5,388	4,999	2,961	265	37	0	**13,651**
2017	5,351	5,016	2,980	265	37	0	**13,651**
2018	5,376	5,040	3,000	265	37	0	**13,718**
Average Annual Growth Rate							
2009-2018	(0.1)%	0.5%	0.8%	(0.0)%	(0.1)%	N/A	**0.3%**

The forecast of residential sales is expected to grow at a slower rate of 0.9% annually compared to average annual growth rate of around 2% experienced past five years. This slow down is mainly due to housing market slowdown and impact of worsening economic conditions. Population growth is expected to continue in the service area, which is driving some of the growth, while usage per customer in the residential class is expected to decline due to economic slowdown during earlier years. Starting with 2012, use per customer is expected to decline mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other conservation programs.

Over the first two years of forecast horizon, forecasted commercial class sales are projected to grow at a slower average annual growth rate of 1.3% compared to historical periods due to the impact of worsening economic conditions. Educational, health service, and government related commercial activity are only sectors expected to still grow during the next two years. During the remaining years of the forecast horizon, commercial sales are expected to grow at a higher average annual rate of 1.7%, which is similar to the average growth rate experienced historically. Usage per customer is projected to decline slightly due to increased equipment efficiency.

Forecasted industrial class sales are projected to decline at an average annual rate of 3.2% during 2009 and 2010 due to impacts of the housing market slowdown and current economic recession affecting mostly wood products and semi-conductor manufacturing. Starting with 2011, industrial sales is expected to grow again at an average annual growth rate of 1.7% reflecting recovery in special food processing and wood products sector, along with continued diversification in the manufacturing base in the state.

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

Washington

Table E.2 summarizes Washington state forecasted sales growth by customer class.

Table E.2 – Forecasted Retail Sales Growth in Washington

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	1,556	1,379	806	159	10	0	**3,910**
2010	1,554	1,382	810	158	10	0	**3,915**
2011	1,559	1,388	807	158	10	0	**3,922**
2012	1,571	1,398	809	158	10	0	**3,947**
2013	1,564	1,408	812	158	10	0	**3,952**
2014	1,562	1,420	815	158	10	0	**3,965**
2015	1,561	1,432	819	158	10	0	**3,980**
2016	1,567	1,448	823	158	10	0	**4,006**
2017	1,564	1,458	826	158	10	0	**4,015**
2018	1,574	1,465	827	158	10	0	**4,035**
Average Annual Growth Rate							
2009-2018	0.1%	0.7%	0.3%	(0.0)%	0.1%	N/A	**0.4%**

The forecast of residential sales is expected to grow at a slower average annual growth rate of 0.4% compared to recent historical growth rates of around 1% due to the impact of housing market slowdown and economic recession. The slight growth in residential class sales is due to continuing customer growth driven by population growth and household formation in the PacifiCorp's service area. Usage per customer is expected to decrease slightly during the early years due to worsening economic conditions. Starting with 2012, use per customer is expected to decline mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation.

Over the first two years of forecast horizon, forecasted commercial class sales are projected to grow at a slower rate of 0.8% compared to historical periods due to the impact of current economic recession. Beyond 2010, commercial sales are expected to grow at a higher average annual rate of 1.5%, which is close to average annual growth rate experienced historically.

The industrial class sales are projected to decline for the first four years of forecast horizon mainly due to housing market slowdown affecting wood products sector. For the remaining part of the forecast period industrial sales are expected to grow slightly reflecting recovery in wood products and food processing sectors.

California

Table E.3 summarizes California state forecasted sales growth by customer class.

Table E.3 – Forecasted Retail Sales Growth in California

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	387	298	51	98	2.49	0	**838**
2010	389	301	51	98	2.47	0	**841**
2011	391	308	71	98	2.47	0	**871**
2012	396	319	81	98	2.48	0	**897**
2013	394	327	88	98	2.47	0	**910**
2014	395	337	91	98	2.47	0	**924**
2015	397	348	91	98	2.47	0	**936**
2016	399	359	91	98	2.48	0	**950**
2017	400	368	91	98	2.47	0	**960**
2018	405	378	91	98	2.47	0	**975**
Average Annual Growth Rate							
2009-2018	0.5%	2.7%	6.6%	0.0%	(0.1)%	N/A	**1.7%**

The rate of growth in residential class sales is driven, by the continuing growth in population in this part of PacifiCorp’s service area. Usage per customer in the residential class is expected to decline due to increasing adoption of more efficient appliances and the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation effective in 2012. .

The continuing population growth also affects sales in the commercial sector through continued commercial customer growth. Additionally, commercial usage per customer is increasing due to greater square footage per building in new construction, increases in the number of offices, and the increasing use of office equipment in all commercial structures. However, some of this growth is being offset from increased equipment efficiency over the forecast horizon.

Declines over the decade in the lumber and wood product industries production resulted in an overall decline in the industrial sales; however, there are indications that this trend has ended and growth in other businesses are expected to continue. During first four years of forecast horizon, industrial sales are expected to grow due to the addition of new industrial customers. For the remaining years sales are expected to remain flat.

Utah

Table E.4 summarizes Utah state forecasted sales growth by customer class.

Table E.4 – Forecasted Retail Sales Growth in Utah

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	6,556	7,410	7,337	189	76	437	**22,005**
2010	6,687	7,589	7,364	189	76	436	**22,341**
2011	6,807	7,826	7,700	189	76	436	**23,034**
2012	6,965	8,074	7,905	189	76	437	**23,646**
2013	6,978	8,271	8,241	189	76	436	**24,192**
2014	7,048	8,528	8,626	189	76	436	**24,904**
2015	7,123	8,788	9,007	189	76	436	**25,618**
2016	7,217	9,064	9,251	189	76	437	**26,234**
2017	7,278	9,300	9,331	189	76	436	**26,610**
2018	7,440	9,564	9,414	189	76	436	**27,119**
Average Annual Growth Rate							
2009-2018	1.4%	2.9%	2.8%	0.0%	0.0%	0.0%	**2.3%**

Utah continues to see natural population growth that is faster than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of in-migration. However, the rate of population growth is expected to be lower in the coming decade as in-migration into the state slows down. Over the forecast horizon, residential sales are expected to grow at a slower rate of 1.7% compared to what has been experienced historically due to slow down in-migration and housing market slowdown in near-term. Usage per customer in the residential class is expected to decline due to recent economic recession during early part of the forecast horizon. Beyond 2012, the decline in use per customer is driven by the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The continuing population growth also affects sales in the commercial sector by continued commercial customer growth. Usage per customer is projected to decline due to recent economic recession during early part of the forecast horizon, and starts increasing again during later years with new construction having greater square footage per building and increasing usage of office equipment. However, some of this growth is being offset from equipment efficiency gains over the forecast horizon.

The industrial class has been experiencing significant industrial diversification in the state and will continue to cause sales growth in the sector. Utah has a strategic location in the western half of the United States, which provides easy access into many regional markets. The industrial base has become more linked to the region and is less dependent on the natural resource base within the state. This provides a strong foundation for continued growth into the future. For the first two years of forecast horizon, industrial sales are expected grow at a much slower rate of 0.6% annually compared to historical average annual growth rate of 3.5% experienced over the past five years. Expansions by mining and natural resources are projected to slowdown with continuing downturn in manufacturing. Starting 2011, industrial sales are expected to grow again at higher rates similar to what was experienced historically, reflecting expected improvement in overall economic conditions.

Idaho

Table E.5 summarizes Idaho state forecasted sales growth by customer class.

Table E.5 – Forecasted Retail Sales Growth in Idaho

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	711	409	1,637	616	2.47	0	**3,375**
2010	719	414	1,648	615	2.51	0	**3,400**
2011	731	422	1,651	615	2.55	0	**3,421**
2012	747	432	1,657	615	2.59	0	**3,454**
2013	749	438	1,772	615	2.64	0	**3,577**
2014	756	450	1,856	615	2.68	0	**3,681**
2015	764	462	1,863	615	2.74	0	**3,707**
2016	776	475	1,871	615	2.80	0	**3,740**
2017	784	485	1,877	615	2.81	0	**3,764**
2018	802	497	1,884	615	2.87	0	**3,800**
Average Annual Growth Rate							
2009-2018	1.3%	2.2%	1.6%	(0.0)%	1.7%	N/A	**1.3%**

The recent migration to Idaho has led the residential sales to grow at an average annual growth rate of around 4.0% during past five years. Over the forecast horizon, the residential sales are still projected to grow but at a slower rate of 1.5% annually compared to historical periods due to expected slow-down in in-migration. Usage per customer is expected to decline mainly due to recent economic recession during earlier years, and due to increased energy efficiency and conservation programs for the later years.

The growth rate for commercial class sales is expected to continue to be strong due to customer growth in response to the increasing residential customer growth resulting further growth in service sectors such as education and health care services. Usage per customer is projected to increase, which has been influenced in part by new construction,, increased air conditioning saturation, office equipment, and exterior lighting. However, this growth is somewhat offset by equipment efficiency gains over the forecast horizon.

Industrial sales are expected to decline in 2009 due the impact of worsening economic conditions, and remain flat until the end of 2012. Industrial sales are expected to increase again in 2013 due to some new customers in the service area.

Wyoming

Table E.6 summarizes Wyoming state forecasted sales growth by customer class.

Table E.6 – Forecasted Retail Sales Growth in Wyoming

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	1,054	1,493	6,898	21	12	0	**9,478**
2010	1,079	1,510	7,296	21	11	0	**9,918**

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2011	1,098	1,537	7,742	21	11	0	**10,410**
2012	1,122	1,569	8,283	22	11	0	**11,008**
2013	1,132	1,597	8,617	22	11	0	**11,379**
2014	1,148	1,629	8,951	23	11	0	**11,762**
2015	1,166	1,660	9,276	23	11	0	**12,138**
2016	1,193	1,698	9,632	24	11	0	**12,559**
2017	1,217	1,729	9,903	24	11	0	**12,884**
2018	1,258	1,763	10,168	25	11	0	**13,225**
Average Annual Growth Rate							
2009-2018	2.0%	1.9%	4.4%	2.2%	(0.5)%	N/A	**3.8%**

Residential sales is expected to grow at a slower average annual rate of 0.8%, compared to an average annual growth rate of around 3% experienced during past five years. Population growth is still expected to continue in the service area, which causes some of the sales growth. Usage per customer in the residential class is expected to decline due to recent economic recession during earlier years. During later years of the forecast horizon, use per customer is expected to decline due to impact of long-term lighting efficiency gains resulting from the 2007 federal energy legislation, effective in 2012.

Over the forecast horizon, commercial class sales are also projected to grow at a slower annual growth rate of 1.3% compared to historical periods. Sales growth is driven mainly by the customer growth in response to still continuing residential customer growth and the growth of the office sector.

Wyoming industrial sales growth, driven by expansion in oil and gas extraction industries, is expected to continue, but at a much reduced rate due to declines in energy prices and worsening economic conditions. Continuing growth in industrial customers in the service area also contributes to the load growth in the residential and commercial customer sectors.

FEBRUARY 2009 LOAD FORECAST UPDATE

PacifiCorp prepared a new load forecast in February 2009 after reviewing actual loads through January 2009. With continuing worsening economic conditions, the Company reviewed the loads in PacifiCorp's service territories, and revised the forecast accordingly to reflect the latest impact on loads and latest forecast of economic variables. Below are the capacity and energy tables similar to those found in Chapter 5. These forecasts are net of DSM-related load reductions.

February 2009 Energy Forecast

Table E.7 – February 2009 Annual Load Growth forecasted in Megawatt-hours

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**60,513,585**	14,717,735	4,339,279	966,290	24,066,263	10,167,695	3,718,077	2,538,247
2010	**61,603,833**	14,810,829	4,344,912	966,218	24,522,312	10,646,811	3,750,820	2,561,930
2011	**63,263,930**	14,921,509	4,371,402	1,004,954	25,404,577	11,188,878	3,785,957	2,586,655
2012	**65,029,943**	15,115,696	4,417,268	1,037,281	26,168,642	11,845,914	3,829,464	2,615,678
2013	**66,466,245**	15,159,619	4,424,099	1,055,642	26,884,446	12,253,897	3,974,809	2,713,732
2014	**67,979,096**	15,223,467	4,443,316	1,071,104	27,682,221	12,674,296	4,088,986	2,795,706
2015	**69,346,652**	15,283,484	4,463,835	1,084,175	28,492,384	13,088,772	4,118,092	2,815,910
2016	**70,712,194**	15,382,412	4,496,642	1,100,268	29,188,167	13,549,959	4,154,171	2,840,577
2017	**71,559,345**	15,402,000	4,506,713	1,109,880	29,596,661	13,908,106	4,178,291	2,857,694
2018	**72,717,605**	15,513,152	4,542,282	1,126,645	30,141,988	14,293,815	4,215,982	2,883,742
Annual Average Growth Rate								
2009-18	**2.1%**	0.6%	0.5%	1.7%	2.5%	3.9%	1.4%	1.4%
2018-28	**1.1%**	0.5%	0.6%	1.3%	1.5%	1.3%	0.8%	0.8%
2009-28	**1.6%**	0.5%	0.6%	1.5%	2.0%	2.5%	1.1%	1.1%

February 2009 System-Wide Coincident Peak Load Forecast

Table E.8 – February 2009 Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**9,941**	2,362	728	158	4,440	1,268	625	361
2010	**10,161**	2,395	737	158	4,546	1,307	649	368
2011	**10,481**	2,419	746	166	4,710	1,371	674	395
2012	**10,805**	2,446	782	172	4,838	1,439	705	423
2013	**11,024**	2,462	763	176	4,968	1,490	737	428
2014	**11,179**	2,486	775	177	5,126	1,538	683	395
2015	**11,425**	2,501	783	180	5,262	1,585	708	406
2016	**11,690**	2,517	790	183	5,382	1,635	746	436
2017	**11,876**	2,530	798	189	5,478	1,678	759	443
2018	**12,110**	2,551	837	189	5,581	1,722	770	461

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
Annual Average Growth Rate								
2009-2018	2.2%	0.9%	1.6%	2.0%	2.6%	3.5%	2.3%	2.8%
2018-2028	1.2%	0.7%	0.8%	1.5%	1.6%	1.3%	0.7%	0.4%
2009-2028	1.7%	0.8%	1.1%	1.7%	2.0%	2.3%	1.5%	1.5%

APPENDIX F – WIND INTEGRATION COSTS AND CAPACITY PLANNING CONTRIBUTIONS

This appendix summarizes the results of PacifiCorp's latest wind integration cost analysis, which will continue to be refined and expanded. This appendix also presents updated wind capacity contribution values using a statistical estimation methodology that was applied for the first time in the Company's 2007 IRP.

For the wind integration cost study, PacifiCorp developed a methodology to support the costs associated with resource portfolio analysis for the IRP as well as costs used in the evaluation of cost effective renewable resources. This approach decomposes the estimation of inter-hour (hour to hour) and intra-hour (within the hour) costs to integrate intermittent renewable resources. For inter-hour costs, these components include day-ahead and hour-ahead wind forecast variability, or what was referred to as system balancing costs in the 2007 IRP.[2] For intra-hour costs, the components include actual forecast variation, "regulation up" requirements, and "regulation down" requirements. These latter costs pertain to operational assessment and planning of wind variability down to 10-minute intervals or less. In addition to this cost breakdown, PacifiCorp reports integration costs for wind added in the PacifiCorp eastern balancing authority area (PACE), the PacifiCorp west balancing authority area (PACW), and a system weighted-average based on installed capacity in each control area.

The wind integration cost section first provides background on these cost components and then describes the estimation methodologies and cost results. Study caveats and areas for further research are also summarized. The costs results are expressed as a function of the amount and timing of wind included in the 2008 IRP preferred portfolio as well as existing wind (Table F.1). The section concludes with a discussion on future tools, approaches, and external coordination opportunities that PacifiCorp is actively considering or exploring to address the consequences of adding large quantities of wind.

Table F.1 – 2008 IRP Preferred Portfolio Wind Resource Additions by Year

Year	Capacity Additions (MW)	Capacity Factor	Region
Existing and Planned through 2010	1,284	--	System
2011	100	29%	Walla Walla
2011	100	29%	Yakima
2012	100	35%	Southwest Wyoming
2013	100	35%	Southwest Wyoming
2014	100	35%	Aeolus Wyoming
2015	150	35%	Aeolus Wyoming
2016	100	35%	Aeolus Wyoming
2017	100	35%	Southwest Wyoming

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[2] PacifiCorp, 2007 Integrated Resource Plan, Appendix J, pp. 193-4.

Year	**Capacity Additions (MW)**	**Capacity Factor**	**Region**
2018	50	35%	Southwest Wyoming
2019	200	35%	Southwest Wyoming
2020	200	35%	Southwest Wyoming
2021	150	35%	Southwest Wyoming
TOTAL	2,734		

Due to a number of project schedules, this wind study was not completed in time to be incorporated into the 2008 IRP portfolio modeling. As discussed in Chapter 7 of Volume 1, a value of $11.75/MWh—based on Portland General Electric Company's latest wind integration study—was used for IRP capacity expansion optimization modeling purposes. While the Company acknowledged the differences between the PacifiCorp and PGE systems and the caveats associated with the PGE study, PacifiCorp believed that the PGE value represented a reasonable proxy until its own study could be completed. If the wind integration cost study yields a significantly different total value, the Company commits to perform a sensitivity study with the System Optimizer capacity expansion model and the 2008 IRP preferred portfolio modeling assumptions to determine the wind resource selection impact of the updated cost value.

WIND INTEGRATION COSTS

Background

In power planning and dispatch, any period in which load or generation varies from a steady value results in an increased cost for the utility to balance out this variation. Variations in the load and wind generation forecasts are managed with balancing activities. Once the hour-ahead schedule is given to the real-time staff, actual variation in load and wind generation within the hour is balanced using system generation resources. Current balancing activities treat wind forecast variations similarly to load forecast deviation; however, special attention is required for the greater percentage variability and near-term volume growth of wind generation.

The components of wind variability which give rise to integration costs can be divided into two groups: inter-hour and intra-hour. The inter-hour components of wind variability are:

- Day-ahead forecast variation: deviation of the long-term wind forecast (prior energy expectations) to the day-ahead forecast for the day prior to power delivery.
- Hour-ahead forecast variation: deviation of hour-ahead forecast from day-ahead forecast for the hour prior to delivery.

The rebalancing or closure of open positions generated as new load and wind forecast data becomes available requires the payment of transaction costs.

The other set of costs to be considered is associated with the intra-hour (within the hour) components of wind variability:

- Actual forecast variation: deviation of actual hourly average energy from the hour-ahead forecast,
- Regulate down: deviation of hourly maximum energy from the energy at the beginning of the hour, measured with ten minute granularity,
- Regulate up: deviation of hourly minimum energy from the energy at the beginning of the hour, measured with ten minute granularity,
- Automatic Generation Control (AGC): fine scale variation of energy over a one to two minute time scale.

These intra-hour factors require the holding of additional reserves above the standard requirement of 5 percent on wind generation. Due to the small impact, yet large analytical requirement, to determine reserves for AGC, this cost component is not addressed in the wind integration study; however, this issue may be pursued in the future as the company gains more experience in this area.

These inter- and intra-hour factors do not include long-term shaping effects. While benefits or costs may arise due to the hourly difference between expected future energy in moving from a flat-dispatched unit such as geothermal to a shaped profile unit such as wind, on a longer-term view, these differences are only the effect of different hourly prices or expected value on the forecasted future energy; therefore, no actual costs are incurred from balancing a new long-term wind pattern with system resource redispatch.

Determination of Incremental Reserve ("Intra-Hour") Requirements

Before all reserve costs can be estimated, the megawatt (MW) quantity of reserves required to maintain system reliability as additional wind in the Eastern and Western balancing authority areas of PacifiCorp's service region must be calculated. In previous wind integration studies, PacifiCorp has not captured the increased load-following reserve requirements caused by wind forecast error within the hour. Increasing the magnitude of wind resources on the system results in an increased reserve requirement due to the fact that wind forecasts are inherently inaccurate, particularly at within-hour granularity. Intra-hour wind variability requires the dispatch of existing units to balance the system as there is no intra-hour market.

Actual Variation

The deviation of the actual hourly average energy from the hour-ahead forecast can be computed given the historical hour-ahead wind generation forecast and actual hourly energy values. This produces statistical hourly distributions of the forecast versus actual energy. If this was the only source of the intra-hour uncertainty, the quantities of reserves may be easier to estimate by taking the 97.5th percentile of the variation distribution which represents two standard deviations of forecast error and the approximate PacifiCorp performance under Control Performance Standard II (CPS II)[3]. Reporting levels of reserves required with a 97.5% confidence interval adds an important reliability dimension to the calculation. While actual day-to-day balancing operations may require less reserves than suggested in this study, attention to tail events is an important consideration for overall system reliability. Additional considerations include the correlation

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[3] The CPS II standard refers to the compliance bounds for the 10-minute average of the Area Control Error.

between forecast error and two additional sources of intra-hour uncertainty: "regulate down" and "regulate up".

Regulate Down

For the purposes of this study, regulate down is the difference between the maximum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves up within an hour, other generation resources are required to reduce their output to compensate for this intra-hour energy deviation. The analysis of 10-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and the ten-minute period of maximum energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp's CPS II standard.

Regulate Up

For the purposes of this study, regulate up is the difference between the minimum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves down within an hour, other resources on the system are required to increase output to compensate for this intra-hour energy deviation. The analysis of 10-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and minimum energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp's CPS II standard.

These three intra-hour factors for different locations are not independent of each other and tend to exhibit some positive and negative correlations that are taken into account when measuring the standard deviation of the simultaneous and combined effect of these factors. Before estimating the total reserves requirement for intra-hour integration, correlations are estimated and applied to determine the total combined uncertainty on a regional level. Two standard deviations for the total probability distribution allowed for computation of reserves associated with all intra-hour factors in the Eastern and Western control areas.

System Balancing ("Inter-Hour") Cost Calculation

The shape of a wind energy delivery pattern is different than the delivery patterns of other generation resources. The wind is intermittent and variable, so a wind pattern that is input as a forecast of expected generation differs considerably from the actual generation delivered. Alternatively, a dispatchable resource, like a CCCT, does maintain a flat schedule of energy delivery so generation units on the system do not have to redispatch and balancing activities do not have to occur to compensate for a block of flat energy. When a short-term wind forecast is created and compared to a longer-term wind energy expectation, balancing activities may have to occur to balance the deviation between the wind forecasts and realized output.

Day-ahead Variation

Because a day-ahead forecast of hourly wind energy always differs from the expected future energy level by some amount, the ideal of delivering a balanced energy profile on a day-ahead basis requires some adjustment in the energy position via transactional balancing. While deviation from a perfectly balanced schedule is normal, estimation of the impacts are assumed to be eliminated by balancing activities to the extent possible.

Fixing the imbalance in real-time is generally more expensive and, to this end, this study assumes that all forecast imbalances are addressed in the day-ahead market. This is limited by the size and availability of standard 25 MW blocks for standard 16-hour or 8-hour (on-peak and off-peak) delivery patterns. PacifiCorp incurs transaction costs every time it trades a block of 25 MW. These transaction costs may vary depending on the time of day and location and are currently estimated to be about $0.50 per MWh over market for purchases to cover a shortfall in forecast, and under market for sales to cover a forecast excess during most transactional hours. This internal assumption is generally accepted by balancing staff and is consistent with the assumption used in Portland General Electric’s wind integration study. Given the hourly difference between the long-term expected wind generation and the historical wind generation forecasts at the day-ahead horizon, these costs may be estimated.

To calculate the transactional costs associated with balancing the hourly long-term expected wind generation to the hourly day-ahead wind schedule, the variation was calculated as the absolute value of the difference between the two forecasts. For October 2008 through April 2009, a sample week of hourly data from all existing wind plants on the system (for which data was available) was chosen for each month[4]. The distinction of costs between the Eastern and Western side of the system is reflective of different degrees of forecast accuracy. The existing data was scaled up to reflect the planned East and West additions to the system, 200 and 1,250 MW, respectively, for a total of 773 MW on the West and 1,784 MW on the East. The total deviation was found for each day for both heavy load and light load hours.

For example, on Day 1, the deviation for all heavy-load hours was added. The same was done for light-load hours. The resulting totals were rounded up to the nearest 25 MW increment to reflect actual transaction sizes available in the day-ahead market. The total daily variation was added up for each sample week and multiplied by an estimated bid-ask spread of $0.50 per MWh. PacifiCorp’s front office provided this bid-ask spread estimate. The total transaction costs incurred for all sample weeks was divided by the total MWh of long-term expected generation for the same sample weeks and presented on a $/expected MWh basis provided in Table F.2. Transaction costs in the table below are lower in the Eastern control area and may be the result of more accurate forecasting, a more uniform wind pattern, and higher locational diversity.

Table F.2 – Wind Inter-hour Day-Ahead Balancing Transaction Costs

System	Wind Expected to Day-Ahead ($/Expected MWh)
West	$0.41
East	$0.23

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[4] This period was chosen due to limited data availability.

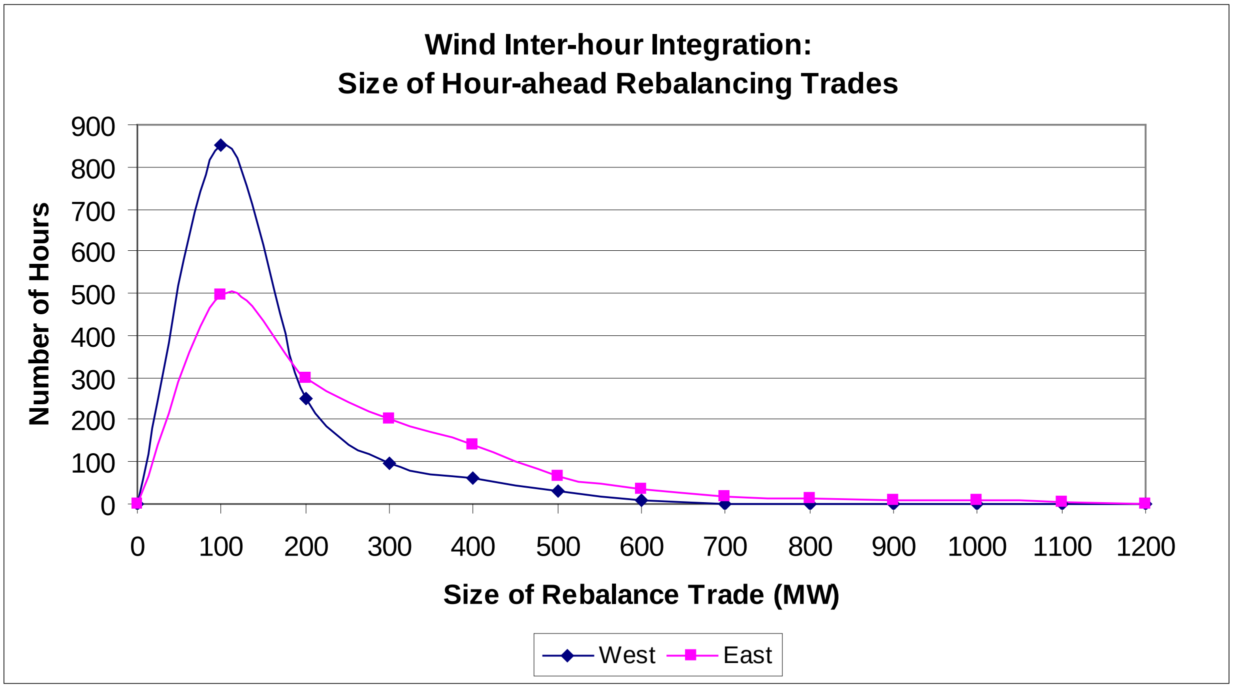
Hour-ahead variation

Similar to the day-ahead variation, the rebalancing of energy to close open positions due to the change in forecasted wind energy from the day-ahead schedule to the hour-ahead schedule also adds transaction costs. Hour-ahead transactions assume transactions in 1 MW increments, but transactions costs are up to twenty-five percent of the per-MWh energy costs. The precise percentage depends on then–current market conditions and the amount of energy traded.

In order to derive the hour-ahead forecast used by real-time for scheduling, a persistence methodology was used. When the real-time traders schedule wind for the upcoming hour, it is assumed that the actual wind generation level from the previous hour will persist for the next hour. In this study, the hour-ahead schedule was based on persistence. The existing October 2008 through April 2009 data was scaled up to reflect the planned East and West additions to the system, 200 and 1,250 MW, respectively, for a total of 773 MW on the West and 1,784 MW on the East. The total deviation was found for each day for both heavy load and light load hours.

The day-ahead to hour-ahead balancing transaction costs were calculated in largely the same fashion with the exception of the bid-ask spread used. Transactions undertaken to correct an imbalance, due to variations between the day-ahead and hour-ahead forecast, are of higher cost, which is dependent upon the quantity of power needed and market conditions. Figure F.1 shows the hourly frequency of various imbalance sizes based on 1,300 hourly deviations, which is constitutes the total number of sample hours.

Figure F.1 –Hour-Ahead Variation Frequency Distribution



It is also generally accepted in the hour-ahead market that, as the size of the transaction increases, the costs associated with transactions increases. Based on the frequency distribution above, a smaller cost is required for transactions of about 50 MW, which are transacted much more frequently. The distribution also indicates that, in general, transaction costs on the west portion of the system will be higher due to lower forecast accuracy. Specific transaction assumptions are listed in Table F.3.

Table F.3 – Inter-hour Hour-Ahead Balancing Transaction Cost Ranges

Trade Size (MW)		Transaction Cost (Bid-ask) Percentage by Region	
Lower Bound	Upper Bound	West	East
0	100	5%	5%
101	200	10%	10%
201	1,000	25%	15%

Table F.3 indicates that as more wind projects are added to the system, forecast improvements are necessary in order to prevent large variations which come with a higher market transaction cost. Consider, on an average basis, if a 100 MW wind project is added to the system, the shape of the distribution of the size of hourly errors will be about the same. As the distribution of error increases in a linear fashion, the cost associated with rebalancing does not. Since costs are greater as the size of transactions increases, the distribution of errors may increase on a linear basis, but costs will increase faster.

Once the hourly variance from the day-ahead forecast to the hour-ahead forecast has been calculated, the specific hourly variance is applied to the corresponding hourly real-time price from an independent energy information company that publishes hourly wholesale power indices. For PACE, Four Corners was used and for PACW, Mid-Columbia was used. The size of the variance determines the transaction cost, which is the product of the hourly price and the corresponding variance percentage. In Table F.4 below, the day-ahead to hour-ahead transaction cost is presented along with the total inter-hour cost for the east and west balancing authority areas.

Table F.4 – Wind Inter-hour Hour-Ahead Balancing Transaction Costs

System	Wind Expected to Day-Ahead ($/Expected MWh)	Wind Day-Ahead to Hour-Ahead ($/Expected MWh)[5]	Total Wind Inter-hour ($/Expected MWh)
West	$0.41	$2.80	$3.21
East	$0.23	$1.89	$2.12

<u>Determination of Incremental Reserve ("Intra-Hour") Requirements</u>

The indicated MW of additional reserves needed to balance the total intra-hour wind generation variations on PacifiCorp's system due to incremental wind addition is unique to each region of

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[5] Values expressed are representative of the average cost to transact for the October 2008 through April 2009 period.

PacifiCorp's system. These values were derived by multiplying the within-hour standard deviation from all wind projects in each of the three regions in this study by a Z score of 1.96 (which is representative of the 97.5% confidence interval and PacifiCorp's CPS II requirement) and is inclusive of all three sources of inter-hour variation discussed. Table F.5 presents the corresponding reserve volumes for each region in the system and reflects fixed volumes of new annual wind projects spread through 2021 consistent with the company's general long-term wind acquisition strategy.

Table F.5 – Total Wind System Intra-hour Reserve Requirement (MW)

Resources	Capacity Additions	Total Reserve Requirement	Incremental Increase	Cumulative Increase
Existing and Planned through 2010	1,284	295.4		
2011	200	312.7	17.3	17.3
2012	100	331.2	18.5	35.8
2013	100	339.1	7.9	43.7
2014	100	349.1	9.9	53.6
2015	150	367.8	18.8	72.4
2016	100	380.5	12.6	85.0
2017	100	385.1	4.6	89.7
2018	50	402.0	16.9	106.6
2019	200	420.9	18.9	125.5
2020	200	433.2	12.3	137.7
2021	150	452.9	19.7	157.5

<u>Incremental Reserve ("Intra-Hour") Cost Calculation</u>

The previous section described the calculation of MW quantities associated with adding wind generation resources. In this section, the calculation of the cost associated with wind additions is described.

As the company installs larger volumes of wind resource generation, the company's cost to integrate these intermittent resources is anticipated to increase. This is because more and more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour-to-hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts often provide the needed flexibility. However, these hydro resources are not of adequate size to integrate all of the anticipated wind variability. Partially loaded gas turbines provide additional flexibility. Due to its low cost, it is economically preferable that coal is fully utilized to serve load rather than backed off to provide wind integration.

The study assumes that PacifiCorp would balance the intermittency of the wind by holding additional reserves on existing and future flexible resources. A reserve resource stack model was developed that is used to estimate both in-the-money and out-of-the-money reserve costs. The modeling of reserves added the requirements for load and reduced the requirement for hydro and contract reserves in the valuation. In-the-money reserve costs are measured by calculating market prices less the cost of thermal dispatch (fuel, variable O&M, CO_2 emission costs, and SO_2 emission costs). Out-of-the-money reserve costs are estimated by calculating the above-market operating costs of a unit dispatched at minimum capacity divided by the total amount of reserve capability available once at minimum load. The reserve requirement is then filled by the lowest cost in-the-money or out-of-the-money thermal resource considering the resource reserve capacities and unit ramp rates. PacifiCorp used market prices at Mona, Mid-Columbia, and Four Corners with the \$45 CO_2 October 2008 price curve (2013 is the assumed start of CO_2 regulation).

The wind reserve results reported in Table F.6 are at the system level and include both existing and incremental wind projects. The reserve results are levelized on a real basis (with inflation effects removed) for the study period 2009 to 2030 by dividing the reserve cost by the wind expected megawatt-hour generation. The existing reserve available data ended in April 2014 so the data was escalated using the prior three-year average. The reserve study considered heavy load and light load hour for the analysis but was limited by the wind reserves calculated on an annual basis.

Table F.6 – Costs for Wind Intra-hour Incremental Reserves

Wind Existing and Incremental Approximately (MW)	System Wind Intra-hour Reserves
2,734	\$9.40

To determine the cost impact of using a lower CO_2 cost, PacifiCorp estimated the intra-hour reserve cost assuming an \$8 CO_2 tax. The wind reserve costs dropped to \$7.51/MWh, expressed in \$2009, representing a 20-percent decline relative the cost under the \$45 CO_2 cost study. It is not necessarily true; however, that increasing the cost of CO_2 equates to a higher reserve cost. This relationship may be a function of near-term natural gas price curves.

Conclusion

The wind integration cost results are presented in Table F.7, and range from \$9.96/MWh to \$11.85/MWh for PacifiCorp's system in 2009 dollars, depending on the CO_2 tax level scenario. The inter-hour wind results were developed by weighting the PACW inter-hour wind costs by 30% (the PACW MW share of the system total) and the PACE wind costs by 70%, then adding the system wind reserves.

Table F.7 – Wind Integration Costs (2009 Dollars)

CO_2 Cost Scenario	System Balancing Cost (Inter-hour)			Intra-hour Cost ($/Expected MWh)	Total ($/Expected MWh)
	Expected to Day-Ahead Cost ($/Expected MWh)	Day-Ahead to Hour-Ahead Cost ($/Expected MWh)	Total Cost ($/Expected MWh)		
$8 tax	$0.28	$2.17	$2.45	$7.51	$9.96
$45 tax	$0.28	$2.17	$2.45	$9.40	$11.85

The system wind integration costs are in line with the $11.75/MWh proxy value used for 2008 IRP portfolio modeling. Consequently, PacifiCorp did not conduct a wind resource sensitivity study using PacifiCorp's updated values.

TOOLS, APPROACHES, AND EXTERNAL OPPORTUNITIES

There are a number of wind integration tools, approaches, and potential external coordination opportunities that the Company has implemented or is actively investigating. These include the following.

- **Real-Time Balancing:** PacifiCorp has significantly advanced its forecasting process. At present, forecasts in advance of real-time scheduling are done at 40 to 45-minutes prior to the delivery hour and on a persistence forecast[6]. Operational experience has shown that persistence based scheduling in real-time significantly reduces forecast error from using model-based techniques in advance of 40 to 45-minutes prior to the delivery hour.

- **Day-to-Day Balancing** - PacifiCorp has retained an external firm to prepare forecasts every six hours for the primary purpose of day-to-day balancing activities. Finding tools to enhance/improve the day-to-day forecast is likely to lead to enhanced real-time forecasting and, therefore, reduced load following reserve requirements during most hours. Specific tools that will require ongoing investigation and/or capital allocation may include: enhanced wind project status feedback (to the external forecasting contractor); on-site radar devices; and/or contracting with third parties who can provide regional real-time wind data or pooling information with other control area operators to obtain consolidated forecasts.

- **Peer Review –** PacifiCorp will consider incorporating the concept of the peer group review for evaluation of its ongoing refinement of wind integration cost estimation methods as part of the IRP public participation process. At present, the industry is suffering from the lack of standardized wind integration study methods. As a result, it is necessary to examine each such study to unravel its assumptions and methodology to be able to understand how it compares to other studies.

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[6] Persistence based scheduling is the practice of scheduling production for the next hour based on then-current production.

- **Curtailment Tools** – A number of tools exist for either curtailing wind project output during those hours where a critical need exists or limiting the impact of wind resources on the system during unusual ramping events. Such tools may include:

  - **Ramp Rate Limiters:** PacifiCorp's General Electric wind turbines in Wyoming include a ramp rate limiter option. This option enables PacifiCorp operators to set a maximum rate by which a wind project's output will change over time (MW/minute) during periods when the wind is ramping up

  - **Curtailment -** PacifiCorp's General Electric wind turbines in Wyoming include a curtailment option. This option enables PacifiCorp operators to curtail or limit the output of wind projects on short notice.

  - **Power Purchase Agreements (PPA) -** Many of PacifiCorp's PPAs include provisions enabling the Company to curtail output for certain reliability events or for other reasons. New PPAs all have such provisions. For example, PPAs entered into via the RFP process all contain such curtailment provisions. Additionally, the company will continuously review and refine PPA contractual requirements for output forecasting, outage reporting and curtailment.

  - **Large Generator Interconnection Agreements** (LGIA) **–** Federal Energy Regulatory Commission LGIAs all contain provisions[7] enabling the transmission provider to curtail or disconnect generation if necessary for reliability reasons.

  - **Mid-Hour Scheduling Practices** – At present, the practice of the **WECC** only compels mid-hour schedule changes when there is an "emergency" on the sink balancing authority area. PacifiCorp currently has other third Party wind generators who schedule wind generation for export out of PACW and PACE. There is no established practice compelling mid-hour schedule changes when the source balancing authority area is having an "emergency" which results in other than comparable service for point-to-point transmission customers as compared to network transmission customers. An evolution of mid-hour scheduling practices at WECC for emergencies involving wind generation could lead to a reduction in load following reserves being held. As the level of wind resources being scheduled for export out of a balancing authority area increases, the need for mid-hour schedule changes can be expected to significantly increase.

  - **Transmission Tariffs –** A variety of new tariffs and/or tariff adjustments can be expected to evolve over time:

    - **Integration Tariff:** At present, PacifiCorp does not have an integration tariff. An integration tariff may be appropriate when a transmission provider must integrate wind projects on an hourly basis that are scheduled off-system. As the demand for renewable resources continues to grow in the WECC, PacifiCorp may see a growing preponderance of interconnected wind projects being scheduled for export out of the

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[7] Appendix G to the LGIA

  balancing authority area. This is the main reason that BPA created an integration tariff. Integration tariffs attempt to appropriately capture the cost of intra-hour integration costs. An integration tariff also sends an appropriate price signal to generator owners regarding the value of good forecasting.

  - **Imbalance Tariff:** PacifiCorp's imbalance tariff should be reviewed to determine if it provides an appropriate price signal to generation owners for good forecasting practices. It may be through the combination of an integration tariff and an imbalance tariff with increasing penalties that wind generation owners will have the incentive to deploy effective forecasting tools.

  - **LGIA:** It may be necessary to evolve FERC standard LGIA language to capture the forecasting diligence and curtailment flexibility required of wind resources by transmission operators who also operate as the balancing authority.

  - **Incentives**: If a transmission operator is also a regulated utility with load service obligation and is subject to RPS, it may be necessary for FERC to consider incentives for the entity who is the recipient of intermittent renewable resources (such as wind) to also be the entity responsible for providing the load-following reserves. Since RPS requirements are load-based, a fair application may be to require the load (i.e., sink control area) receiving the intermittent resource to either provide the load-following reserves necessary or telemeter the resource into its own balancing authority area.

- **Wind-only Balancing Authorities –** Some entities in the Pacific Northwest appear willing to pursue formation of a wind-only balancing authority. Here, an entity would contribute their wind resource into the balancing authority, schedule out of the balancing authority, and be responsible for their pro-rata share of intra-hour integration costs. Any entity in the market would be eligible to bid in load-following services to perform the balancing. This effort is only at the conceptual stage.

- **Reserve Sharing:** The creation of bilateral arrangements in addition to that found in the NWWP.

- **Balancing Market**: The creation of a 10-minute balancing market would provide accurate and appropriate price signals to owners of wind generation and would most likely be incorporated into integration tariffs in lieu of capacity costs.

- **ACE Pooling:** ACE pooling is yet another way to spread or socialize volatility associated with wind resources across multiple balancing authority areas.

- **Independent System Operator (ISO):** A reassessment of combining multiple balancing authorities.

- **Flexible Resources**: Creating more accurate forecasts, curtailing wind resources when necessary, and deploying one or more of the tools discussed above, can be expected to help optimize and minimize the amount of load-following reserves that a control area must carry to integrate wind resources. Ultimately, this will not be enough, leading to the need for significant transmission investments and/or an ISO. It is reasonable to expect that flexible resources will be required to manage the significant influx of wind resources that is likely to result from a Federal RPS, or to respond to increasing RPS standards in states like California. A significant policy issue centers on the payment for these flexible resources when they are required to maintain control area reliability. A time honored alternative is to apply the costs on a causation basis or socialize them in some fashion as deemed by the Federal Energy Regulatory Commission.

WIND CAPACITY PLANNING CONTRIBUTION

For the 2008 IRP, PacifiCorp used the Z statistic method[8] for estimating peak load capacity contributions on a monthly basis for incremental 100 MW blocks of wind capacity at each site reflected in the IRP models. This method is based on estimating the effective load carrying capability of wind. No changes to the methodology took place for the capacity contribution update; wind output data was updated based on new information obtained for resources added to PacifiCorp's system.

The results of the updated analysis as applied to the proxy (100-megawatt) wind resource options are shown in Table F.8. The July peak load carrying capability (PLCC) values are highlighted, since these are used by the capacity expansion model for determining how capacity reliability constraints are met.

Key observations from these results include the following:

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

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[8] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

Table F.8 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource by Capacity Factor	Resource Size (Nameplate MW)	Jan	Feb	Mar	Apr	May	Jun	July PLCC	Aug	Sep	Oct	Nov	Dec
West Main, 35%	100	0.7	6.9	3.5	4.2	2.6	3.2	1.8	2.0	1.9	3.4	3.1	26.5
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	20.4
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.4
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4
West Main, 29%	100	0.0	2.9	0.0	1.0	0.0	0.0	0.2	0.0	0.0	0.9	1.1	16.4
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.8
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Main, 24%	100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyoming, 35%	100	4.2	30.5	14.4	0.0	1.3	2.9	5.2	8.1	3.5	0.8	13.2	10.3
	200	0.1	26.6	10.0	0.0	0.0	0.3	3.7	6.1	0.3	0.0	8.0	6.0
	300	0.0	22.8	5.7	0.0	0.0	0.0	2.3	4.2	0.0	0.0	2.9	1.7
	400	0.0	18.9	1.3	0.0	0.0	0.0	0.9	2.3	0.0	0.0	0.0	0.0
	500	0.0	15.1	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0
Wyoming, 29%	100	0.3	24.0	9.3	0.0	0.0	0.0	3.1	5.0	0.0	0.0	8.3	5.6
	200	0.0	20.4	5.3	0.0	0.0	0.0	2.3	3.7	0.0	0.0	3.6	1.9
	300	0.0	16.7	1.4	0.0	0.0	0.0	1.5	2.4	0.0	0.0	0.0	0.0
	400	0.0	13.0	0.0	0.0	0.0	0.0	0.6	1.1	0.0	0.0	0.0	0.0
	500	0.0	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyoming, 24%	100	0.0	17.9	4.2	0.0	0.0	0.0	0.8	1.3	0.0	0.0	3.1	1.0
	200	0.0	14.1	0.5	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0
	300	0.0	10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	400	0.0	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Yakima, 29%	100	2.8	3.0	4.8	8.0	4.6	6.7	4.7	6.3	8.7	10.2	1.8	27.9
	200	0.0	0.0	0.9	4.2	1.7	6.0	4.4	2.7	5.0	4.1	0.0	21.2
	300	0.0	0.0	0.0	0.4	0.0	5.2	4.0	0.0	1.4	0.0	0.0	14.6
	400	0.0	0.0	0.0	0.0	0.0	4.4	3.6	0.0	0.0	0.0	0.0	7.9
	500	0.0	0.0	0.0	0.0	0.0	3.6	3.2	0.0	0.0	0.0	0.0	1.2
Yakima, 24%	100	2.3	2.2	3.1	6.0	3.1	4.5	3.0	4.5	5.5	7.4	0.6	22.9
	200	0.0	0.0	0.2	3.3	0.9	4.1	2.8	2.2	2.7	2.2	0.0	16.3
	300	0.0	0.0	0.0	0.6	0.0	3.8	2.7	0.0	0.0	0.0	0.0	9.8
	400	0.0	0.0	0.0	0.0	0.0	3.4	2.5	0.0	0.0	0.0	0.0	3.3
	500	0.0	0.0	0.0	0.0	0.0	3.0	2.3	0.0	0.0	0.0	0.0	0.0

Regional Resource by Capacity Factor	Resource Size (Nameplate MW)	Jan	Feb	Mar	Apr	May	Jun	July PLCC	Aug	Sep	Oct	Nov	Dec
Goshen, 29%	100	12.9	31.0	28.0	23.6	24.4	23.8	16.1	30.0	27.8	17.0	27.9	24.4
	200	8.4	25.4	20.6	18.7	19.7	18.0	13.5	25.2	23.1	12.7	21.5	18.4
	300	3.9	19.8	13.2	13.8	15.0	12.2	10.8	20.4	18.4	8.4	15.1	12.4
	400	0.0	14.2	5.8	9.0	10.3	6.5	8.2	15.7	13.8	4.2	8.7	6.4
	500	0.0	8.6	0.0	4.1	5.7	0.7	5.5	10.9	9.1	0.0	2.4	0.4
Goshen, 24%	100	10.6	25.3	23.9	18.7	20.0	20.1	12.4	24.8	22.2	13.1	23.0	20.7
	200	7.0	20.2	17.1	14.7	15.9	15.1	10.7	20.7	18.2	9.3	17.1	15.5
	300	3.4	15.0	10.2	10.6	11.9	10.1	9.0	16.6	14.3	5.5	11.2	10.4
	400	0.0	9.9	3.4	6.5	7.8	5.1	7.2	12.5	10.3	1.8	5.3	5.2
	500	0.0	4.8	0.0	2.4	3.8	0.2	5.5	8.4	6.4	0.0	0.0	0.1
Utah, 29%	100	13.6	11.1	33.1	40.8	51.0	42.4	37.6	38.2	36.2	28.4	22.0	21.2
	200	10.3	9.1	28.0	35.2	45.7	38.5	34.1	34.0	31.5	23.6	18.4	17.1
	300	7.0	7.0	22.8	29.5	40.3	34.6	30.7	29.9	26.9	18.8	14.8	13.1
	400	3.6	5.0	17.6	23.9	35.0	30.7	27.2	25.8	22.3	14.0	11.2	9.0
	500	0.3	2.9	12.5	18.3	29.7	26.8	23.8	21.7	17.6	9.2	7.6	5.0
Utah, 24%	100	11.7	7.8	24.8	35.5	41.7	32.8	27.3	30.0	27.0	24.6	16.9	17.4
	200	8.5	6.3	20.4	29.9	36.7	28.9	24.2	26.1	22.4	19.9	13.8	13.8
	300	5.3	4.8	16.0	24.2	31.6	25.1	21.0	22.2	17.9	15.3	10.7	10.2
	400	2.0	3.3	11.5	18.6	26.5	21.2	17.9	18.3	13.3	10.6	7.7	6.6
	500	0.0	1.8	7.1	13.0	21.4	17.4	14.7	14.4	8.8	6.0	4.6	3.1
Walla Walla, 35%	100	3.2	3.4	7.2	11.0	6.3	9.6	7.2	8.5	13.2	13.0	3.6	33.3
	200	0.0	0.0	1.9	5.6	2.3	8.1	6.3	3.3	8.2	5.5	0.0	26.3
	300	0.0	0.0	0.0	0.3	0.0	6.6	5.5	0.0	3.3	0.0	0.0	19.2
	400	0.0	0.0	0.0	0.0	0.0	5.1	4.6	0.0	0.0	0.0	0.0	12.2
	500	0.0	0.0	0.0	0.0	0.0	3.6	3.7	0.0	0.0	0.0	0.0	5.2
Walla Walla, 29%	100	2.7	2.4	5.6	8.8	4.6	7.0	5.2	6.7	9.8	10.0	2.7	27.1
	200	0.0	0.0	1.7	5.4	1.9	6.2	4.8	3.3	6.1	3.8	0.0	20.4
	300	0.0	0.0	0.0	1.9	0.0	5.4	4.3	0.0	2.4	0.0	0.0	13.8
	400	0.0	0.0	0.0	0.0	0.0	4.6	3.8	0.0	0.0	0.0	0.0	7.1
	500	0.0	0.0	0.0	0.0	0.0	3.9	3.4	0.0	0.0	0.0	0.0	0.4
Walla Walla, 24%	100	2.1	1.5	3.4	6.4	3.0	4.6	3.3	4.9	6.2	7.3	1.3	21.9
	200	0.0	0.0	0.5	4.1	1.1	4.2	3.1	2.6	3.4	2.0	0.0	15.4
	300	0.0	0.0	0.0	1.8	0.0	3.9	2.9	0.3	0.5	0.0	0.0	8.9
	400	0.0	0.0	0.0	0.0	0.0	3.5	2.7	0.0	0.0	0.0	0.0	2.5
	500	0.0	0.0	0.0	0.0	0.0	3.2	2.5	0.0	0.0	0.0	0.0	0.0

*The generation data used to determine the PLCC for the generic Utah wind resource was derived from a single bid from the 2003 Renewables RFP. When compared to generation from qualifying facilities within the general region, the estimates appear reasonable.

APPENDIX G – DSM DECREMENT ANALYSIS

CLASS 2 DSM DECREMENT ANALYSES

This section presents the results of the Class 2 demand-side management decrement analysis. For this analysis, the preferred portfolio was used to calculate the decrement value of various types of Class 2 programs following the methodology described in Chapter 7. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of potential new programs between IRP cycles. Note that for the next IRP, the company intends to model Class 2 DSM programs as options in the CEM.

Modeling Results

For the 2008 IRP, results are provided for both the $8 and $45 CO_2 tax levels to provide a perspective on CO_2 tax impacts on DSM Decrement values. For each tax level there are two tables and two charts providing an east and west nominal dollar per megawatt values. Tables G.1 and G.2 show the nominal results of the 12 11 decrement cases for each year of the 2017-year study period. Although no resources were deferred or eliminated from the portfolio due to the addition of Class 2 decrements, there is value in having to produce less generation to meet a smaller load. Consistent with the results for the 2007 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The commercial lighting, residential lighting, and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table G.1 – Annual Nominal Avoided Costs for Decrements, $8 CO2 Tax, 2010-2017

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)							
		2010	2011	2012	2013	2014	2015	2016	2017
EAST									
Residential Cooling	7%	52.83	58.07	61.88	73.26	69.99	75.43	82.86	93.08
Residential Lighting	60%	36.26	42.45	45.74	52.64	52.19	54.07	57.62	65.19
Residential Whole House	46%	36.61	42.33	45.54	52.09	52.12	53.99	57.92	65.67
Commercial Cooling	16%	44.08	49.76	53.28	59.67	58.96	61.71	67.75	76.04
Commercial Lighting	49%	37.02	43.44	46.09	52.92	52.77	54.55	58.36	65.96
System East System Load Shape	65%	35.01	40.62	43.85	50.50	50.66	52.16	55.99	63.10
WEST									
Residential Cooling	20%	45.46	54.20	57.77	65.81	65.06	73.29	81.77	87.30
Residential Heating	28%	40.65	50.96	53.06	55.86	56.89	61.13	66.48	71.37
Residential Lighting	60%	41.67	50.08	52.78	58.11	58.11	64.22	71.04	75.78
Commercial Cooling	16%	44.37	52.76	56.47	63.35	63.35	71.19	78.97	84.60
Residential Whole House	35%	40.86	49.54	52.44	57.27	57.90	63.27	69.45	73.94
Commercial Lighting	49%	40.94	49.62	52.39	57.38	58.28	63.77	69.64	74.96
System West System Load Shape	67%	40.46	48.34	50.81	56.11	56.41	62.06	68.65	73.05

Table G.2 – Annual Nominal Avoided Costs for Decrements, $8 CO2 Tax, 2018-2026

	Decrement Values (Nominal $/MWh)								
Decrement Name	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
EAST									
Residential Cooling	102.24	112.31	121.93	112.80	112.66	124.13	124.39	135.27	145.24
Residential Lighting	70.62	78.45	79.26	78.82	80.00	85.72	89.19	95.44	98.77
Residential Whole House	71.16	79.20	80.09	78.90	80.18	86.15	88.88	95.27	98.67
Commercial Cooling	84.04	92.00	96.26	92.70	95.08	100.60	104.44	116.81	122.93
Commercial Lighting	70.47	78.29	78.36	78.19	79.21	84.77	87.05	94.65	98.23
System East System Load Shape	68.27	75.81	76.78	75.78	77.21	83.04	85.74	92.24	95.51
WEST									
Residential Cooling	93.85	94.81	95.96	91.33	93.32	98.57	105.22	102.35	104.04
Residential Heating	74.67	72.50	71.74	72.95	73.76	79.03	84.11	86.21	86.37
Residential Lighting	80.32	79.57	79.66	78.89	79.65	85.08	89.11	91.42	91.06
Commercial Cooling	89.91	90.65	92.57	88.36	91.16	95.41	101.51	102.57	101.83
Residential Whole House	78.50	77.34	77.06	76.33	78.12	83.98	86.93	87.72	87.72
Commercial Lighting	79.57	79.13	78.92	78.38	79.88	85.30	87.32	89.74	90.80
System West System Load Shape	77.82	76.59	77.55	75.90	77.41	82.75	85.88	88.18	88.50

Figures G.1 and G.2 show the decrement costs, at the $8 CO_2 tax level, for each end use along with the average annual forward market price for that location: Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.

Figure G.1 – East Decrement Price Trends

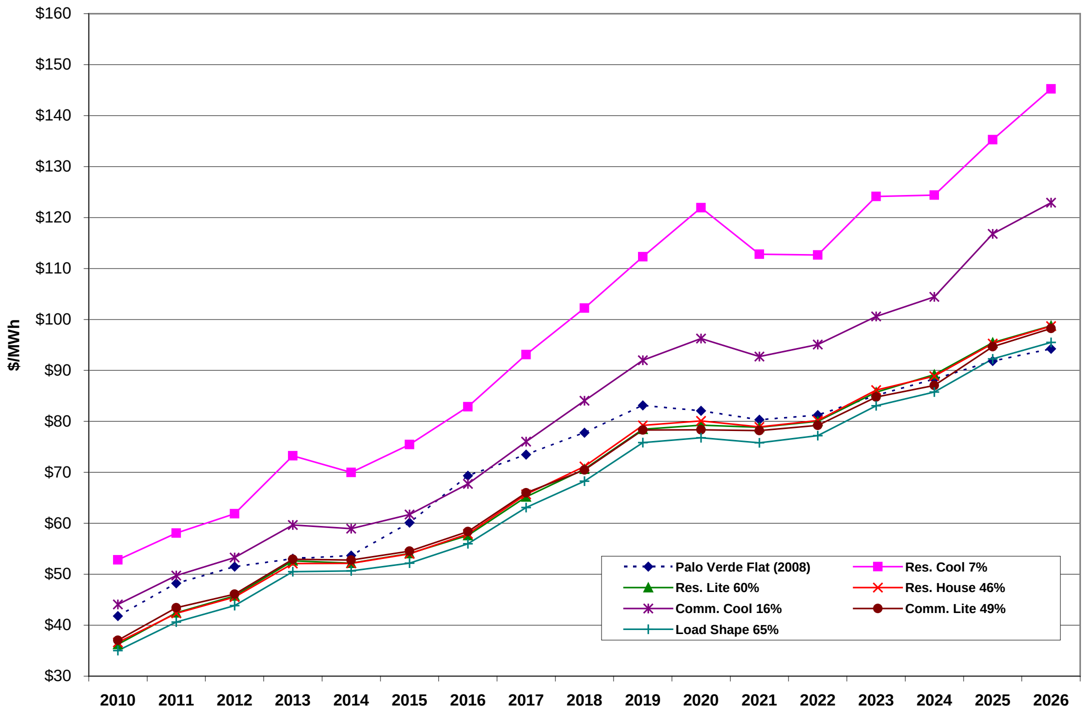


Figure G.2 – West Decrement Price Trends

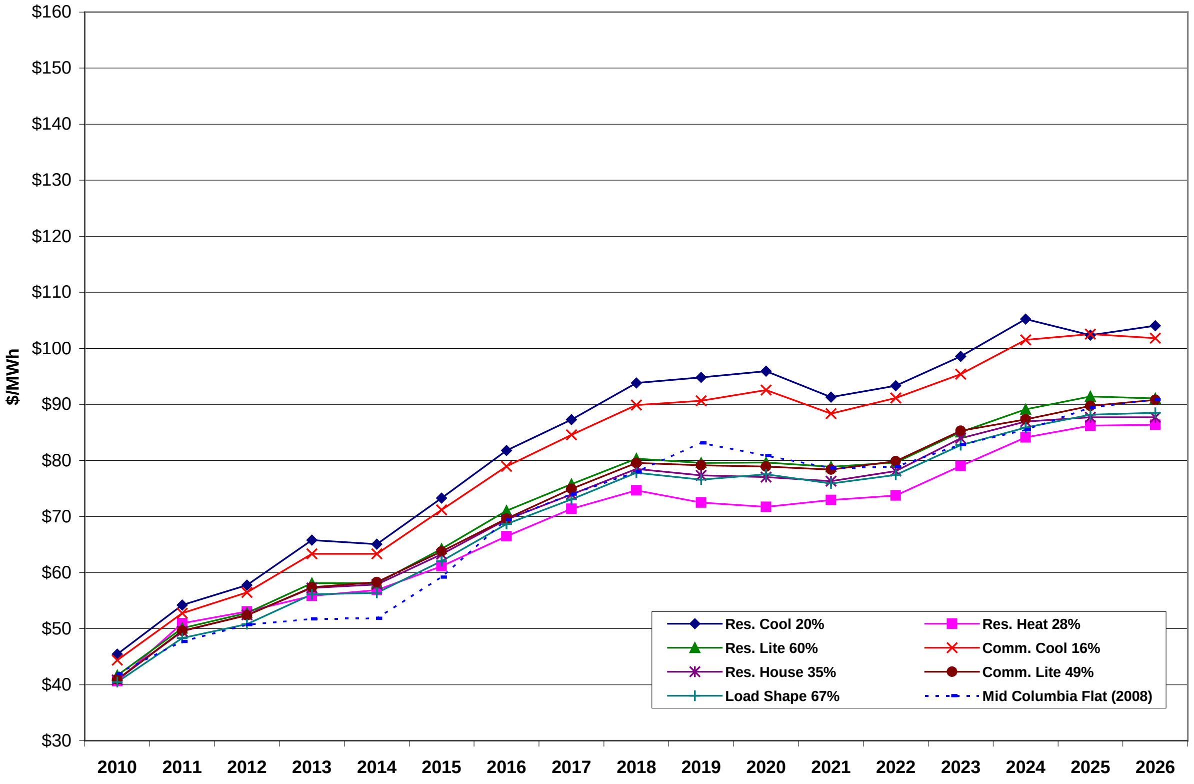


Table G.3 – Annual Nominal Avoided Costs for Decrements, $45 CO2 Tax, 2010-2017

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)							
		2010	2011	2012	2013	2014	2015	2016	2017
EAST									
Residential Cooling	7%	53.70	73.94	74.98	117.68	116.62	122.25	135.21	144.46
Residential Lighting	60%	31.96	52.07	56.66	94.01	95.14	99.41	104.35	111.92
Residential Whole House	46%	32.57	51.83	56.38	93.24	94.45	99.71	105.21	112.12
Commercial Cooling	16%	43.18	63.20	65.63	102.02	104.76	109.17	117.81	124.47
Commercial Lighting	49%	32.54	52.90	57.46	93.25	96.33	100.21	104.79	111.92
East System Load Shape	65%	30.75	49.99	54.65	91.53	92.74	96.96	101.58	109.26
WEST									
Residential Cooling	20%	59.03	72.98	74.52	109.12	112.50	120.10	130.56	137.63
Residential Heating	28%	48.29	61.90	64.46	92.60	96.72	103.87	109.12	117.53
Residential Lighting	60%	52.62	65.45	66.90	97.27	100.74	108.47	116.47	123.88
Commercial Cooling	16%	57.25	71.28	73.28	104.00	109.54	116.75	127.23	133.53
Residential Whole House	35%	50.99	63.52	65.63	95.82	99.57	107.75	113.38	120.46
Commercial Lighting	49%	49.80	63.75	65.81	94.58	99.59	107.17	114.58	122.07
West System Load Shape	67%	51.08	63.26	64.58	94.71	98.48	105.64	113.12	120.18

Table G.4 – Annual Nominal Avoided Costs for Decrements, $45 CO2 Tax, 2018-2026

	Decrement Values (Nominal $/MWh)								
Decrement Name	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
EAST									
Residential Cooling	152.82	158.52	180.89	165.62	172.36	178.33	172.47	185.17	188.46
Residential Lighting	116.88	125.76	130.84	129.93	134.57	141.52	140.90	143.71	144.93
Residential Whole House	116.75	124.37	132.11	129.20	133.77	141.87	141.18	143.20	144.61
Commercial Cooling	132.18	141.85	150.46	146.17	152.92	158.08	158.57	166.04	170.87
Commercial Lighting	115.94	124.05	129.78	127.73	133.24	138.94	140.62	142.57	145.73
East System Load Shape	114.21	121.38	127.20	125.65	130.03	136.92	136.81	139.36	140.93
WEST									
Residential Cooling	142.50	145.06	152.31	146.21	150.59	156.77	159.62	152.27	148.50
Residential Heating	120.50	118.93	122.56	123.06	127.82	133.85	136.06	133.37	130.60
Residential Lighting	126.32	127.27	132.71	130.32	135.19	140.90	141.74	138.77	136.02
Commercial Cooling	138.41	139.31	146.46	140.89	148.89	152.79	158.48	149.99	147.43
Residential Whole House	124.10	122.40	129.88	126.73	132.48	138.68	139.15	134.55	132.83
Commercial Lighting	124.51	124.80	131.95	128.38	134.59	139.90	141.22	136.24	134.93
West System Load Shape	123.39	122.35	129.20	125.80	131.20	137.05	137.61	134.76	132.21

Figures G.1 3 and G.2 3 show the decrement costs, at the $45 CO2 tax level, for each end use along with the average annual forward market price for that location: Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.

Figure G.3 – East Decrement Price Trends for $45 CO2 Tax Level

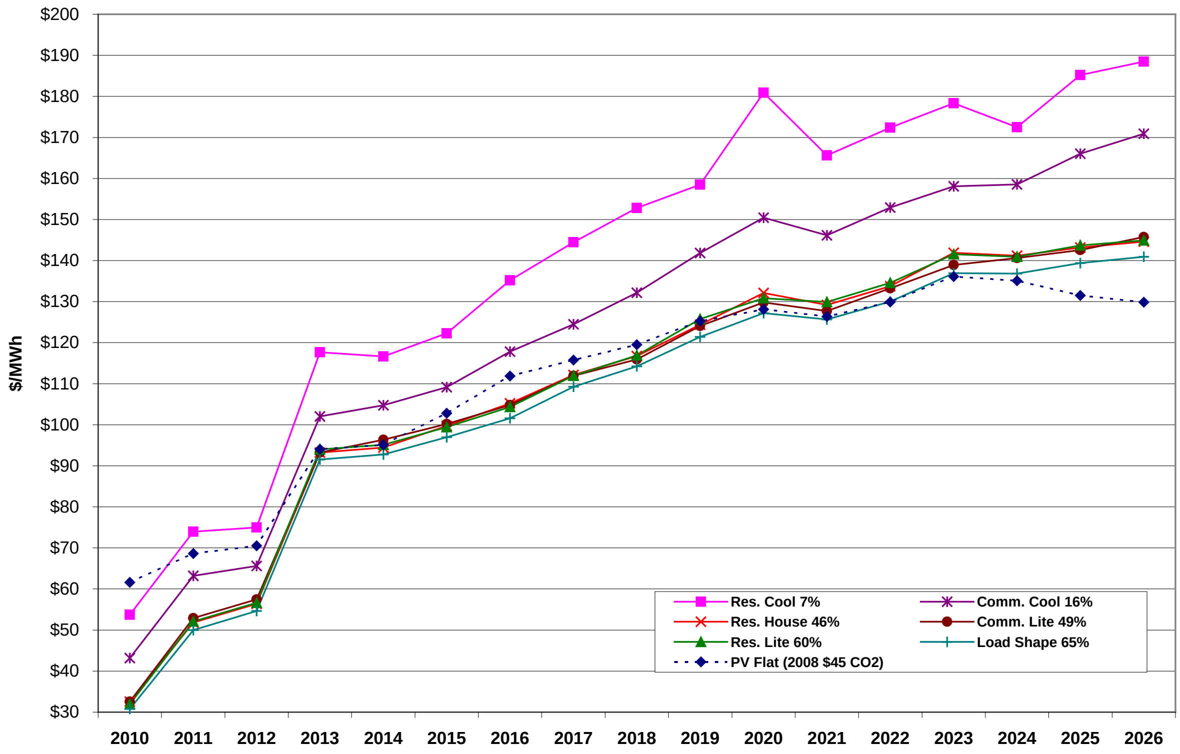
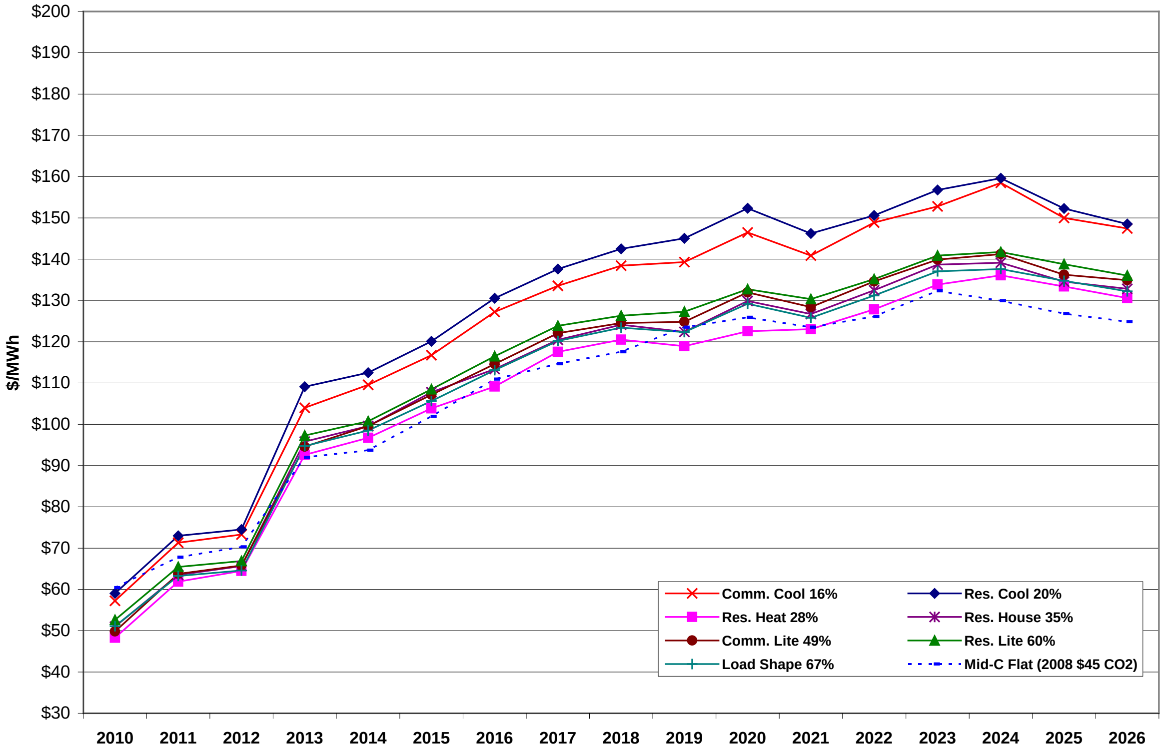


Figure G.4 – West Decrement Price Trends for $45 CO2 Tax Level



APPENDIX H – LOAD AND RESOURCE BALANCE WITH LAKE SIDE II INCLUDED AS A PLANNED RESOURCE IN 2012

The following tables and charts report load and resource balance information for capacity and energy assuming that the Lake Side II combined-cycle plant (with a 596 MW summer capability) is included as a planned resource in 2012. As noted in the IRP main volume, PacifiCorp's initial portfolio analysis assumed the inclusion of this resource.

Table H.1 – Capacity Loads and Resources including Lake Side II (12% Target Reserve Margin)

Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East										
Thermal	5,983	5,998	6,025	6,662	6,662	6,674	6,675	6,683	6,684	6,459
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
QF	151	151	151	151	151	151	151	151	151	151
Interruptible	237	237	237	237	237	237	237	237	237	237
Transfers	876	952	602	235	263	465	230	230	393	589
East Existing Resources	**8,636**	**8,572**	**8,284**	**8,384**	**8,422**	**8,645**	**8,418**	**8,415**	**8,589**	**8,571**
Load	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	**7,538**	**7,717**	**7,908**	**8,151**	**8,388**	**8,524**	**8,774**	**9,048**	**9,150**	**9,355**
Planning reserves	745	785	803	853	880	895	924	958	969	993
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	**815**	**855**	**874**	**923**	**951**	**966**	**995**	**1,029**	**1,040**	**1,063**
East Obligation + Reserves	**8,352**	**8,572**	**8,781**	**9,074**	**9,339**	**9,490**	**9,769**	**10,077**	**10,190**	**10,418**
East Position	**284**	**1**	**(498)**	**(690)**	**(917)**	**(845)**	**(1,350)**	**(1,662)**	**(1,601)**	**(1,848)**
East Reserve Margin	**16%**	**12%**	**6%**	**4%**	**1%**	**2%**	**(3%)**	**(6%)**	**(5%)**	**(8%)**
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydro	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
DSM	-	-	-	-	-	-	-	-	-	-
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
QF	120	120	120	120	120	120	120	120	120	120
Transfers	(878)	(953)	(603)	(235)	(264)	(465)	(229)	(229)	(392)	(588)
West Existing Resources	**4,507**	**4,242**	**4,150**	**3,649**	**3,691**	**3,492**	**3,840**	**3,833**	**3,654**	**3,483**
Load	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	**3,892**	**3,912**	**3,780**	**3,845**	**3,896**	**3,980**	**3,927**	**3,932**	**4,001**	**4,086**
Planning reserves	310	325	363	448	450	464	458	459	467	474
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	**316**	**332**	**370**	**454**	**457**	**471**	**464**	**465**	**473**	**480**
West Obligation + Reserves	**4,208**	**4,243**	**4,149**	**4,299**	**4,353**	**4,451**	**4,391**	**4,397**	**4,474**	**4,566**
West Position	**299**	**(1)**	**0**	**(650)**	**(662)**	**(958)**	**(551)**	**(564)**	**(820)**	**(1,082)**
West Reserve Margin	**20%**	**12%**	**12%**	**(5%)**	**(5%)**	**(12%)**	**(2%)**	**(2%)**	**(9%)**	**(14%)**
System										
Total Resources	**13,143**	**12,815**	**12,433**	**12,033**	**12,112**	**12,137**	**12,258**	**12,248**	**12,243**	**12,054**
Obligation	**11,430**	**11,628**	**11,687**	**11,996**	**12,284**	**12,504**	**12,701**	**12,980**	**13,151**	**13,441**
Reserves	**1,131**	**1,187**	**1,243**	**1,377**	**1,407**	**1,437**	**1,459**	**1,494**	**1,513**	**1,543**
Obligation + Reserves	**12,561**	**12,815**	**12,931**	**13,373**	**13,692**	**13,940**	**14,160**	**14,474**	**14,664**	**14,984**
System Position	**583**	**(0)**	**(498)**	**(1,340)**	**(1,579)**	**(1,803)**	**(1,902)**	**(2,226)**	**(2,421)**	**(2,930)**
Reserve Margin	**17%**	**12%**	**8%**	**1%**	**(1%)**	**(2%)**	**(3%)**	**(5%)**	**(6%)**	**(10%)**

Table H.2 – System Capacity Loads and Resources including Lake Side II (15% Target Reserve Margin)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
System										
Total Resources	13,143	12,815	12,433	12,033	12,112	12,137	12,258	12,248	12,243	12,054
Obligation	11,430	11,628	11,687	11,996	12,284	12,504	12,701	12,980	13,151	13,441
Reserves	1,395	1,464	1,535	1,703	1,740	1,776	1,805	1,848	1,872	1,910
Obligation + Reserves (15%)	12,824	13,092	13,222	13,698	14,024	14,280	14,505	14,828	15,023	15,351
System Position	319	(277)	(789)	(1,665)	(1,912)	(2,143)	(2,247)	(2,580)	(2,780)	(3,297)
Reserve Margin	18%	13%	8%	1%	(1%)	(2%)	(3%)	(5%)	(6%)	(10%)

Figure H.1 – System Capacity Position Trend including Lake Side II

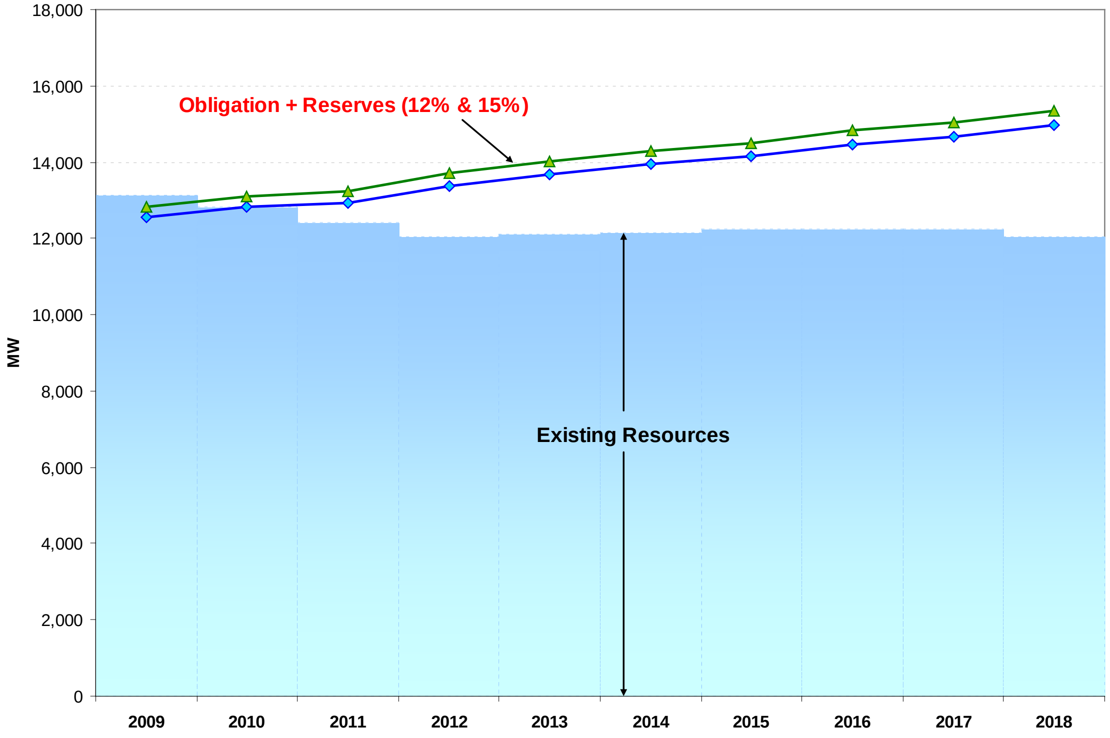


Figure H.2 – East Capacity Position Trend including Lake Side II

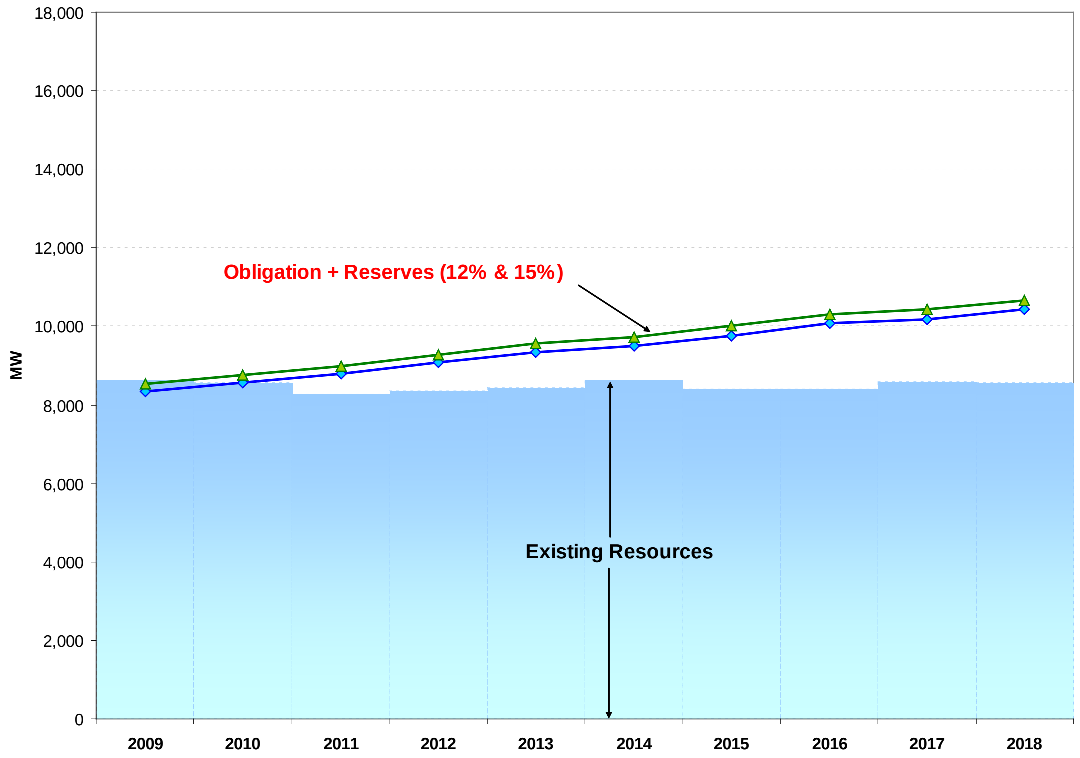


Figure H.3 – System Average Monthly and Annual Energy Balances including Lake Side II

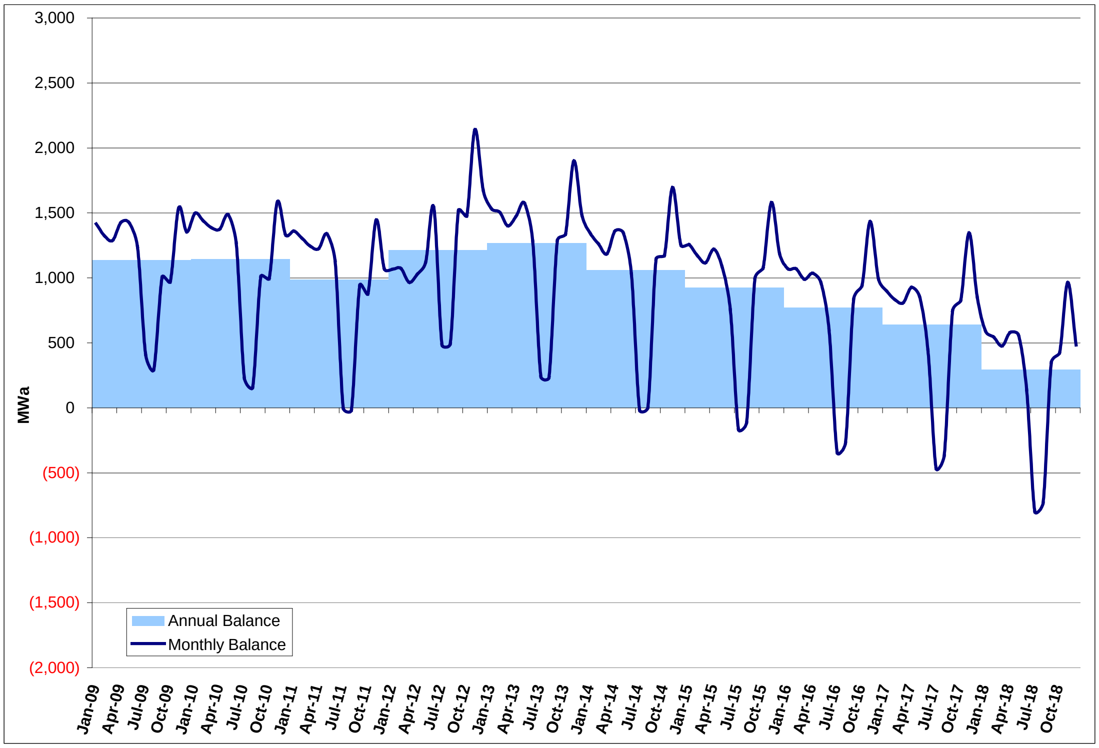
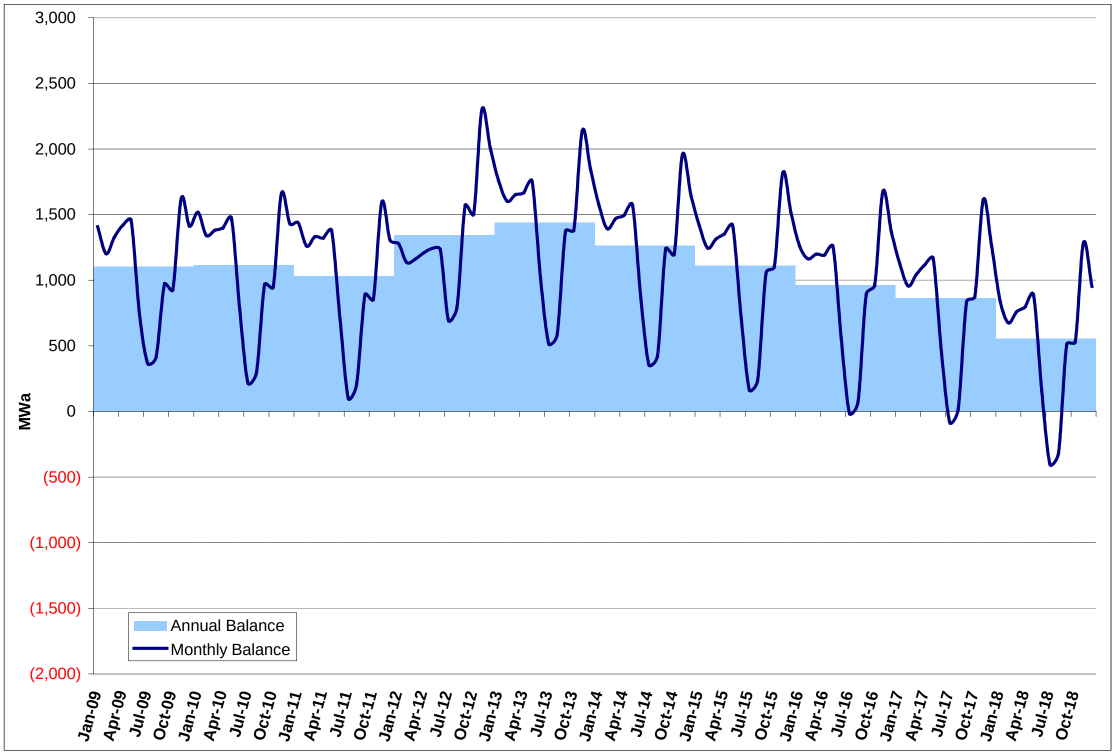


Figure H.4 – East Average Monthly and Annual Energy Balances including Lake Side II



Let's turn the answers on.

2008

Integrated Resource Plan

Volume I

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

May 28, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2008 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: Foot 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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1. EXECUTIVE SUMMARY

PacifiCorp's 2008 Integrated Resource Plan (2008 IRP), representing the 10th plan submitted to state regulatory commissions, presents a framework of future actions to ensure PacifiCorp continues to provide reliable, reasonable-cost service with manageable risk to its customers. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties.

The key elements of the 2008 IRP include a finding of resource need—focusing on the 10-year period 2009-2018, the preferred portfolio of supply-side and demand-side resources to meet this need, and an action plan that identifies the steps the Company will take during the next two to four years to implement the plan. The resources identified in the 2008 IRP preferred portfolio are considered proxy resources that guide procurement efforts, and do not constitute the actual resources that would be acquired as part of future procurement initiatives.

Significant changes reflected in this IRP relative to the 2007 IRP (filed in May 2007) include:

- A decrease in resource need: the system becomes short on capacity in 2011 rather than 2010 due to lower forecasted loads and new resource additions.
- Acquisition of the 520 megawatt (MW) Chehalis gas plant and 175 MW of additional wind resources added in 2008.
- New IRP guidelines issued by the Oregon Public Utility Commission on the treatment of carbon dioxide (CO_2) regulatory risk.
- Incorporation of the Energy Gateway Transmission project in the portfolio analysis.
- State commission 2007 IRP acknowledgment orders calling for modeling methodology changes and the expansion of resource options to consider, including energy efficiency measures (Class 2 demand-side management programs) and additional renewable energy technologies such as solar and geothermal.

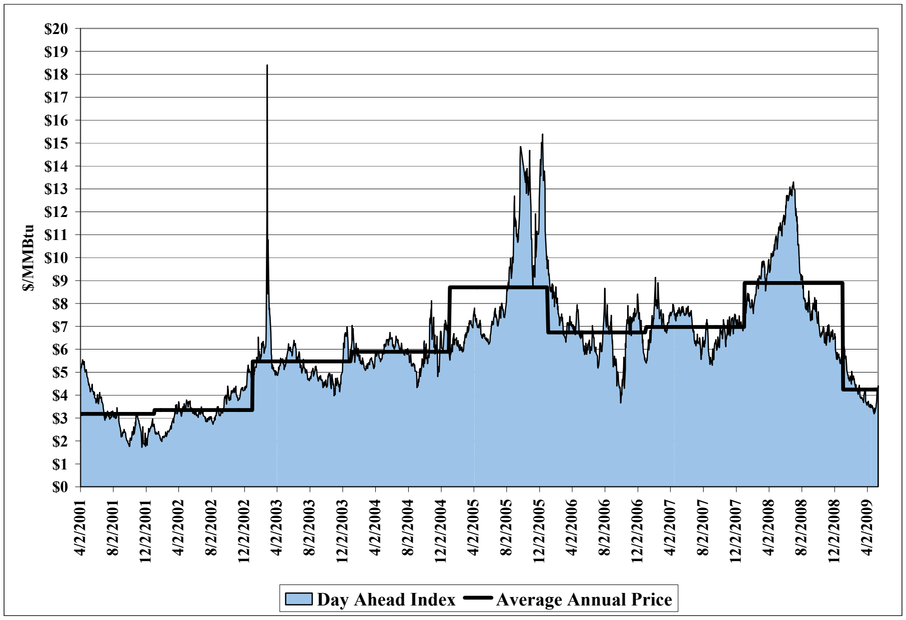
THE INTEGRATED RESOURCE PLANNING ENVIRONMENT

- For capital expenditure planning, the Company's challenge has been to minimize customer rate impacts in light of a substantial capital spending requirement needed to address customer load growth, support government environmental and energy policies, and maintain transmission grid reliability. To address this challenge, PacifiCorp is scrutinizing capital projects for cost reductions or deferrals that make economic sense in today's market environment.

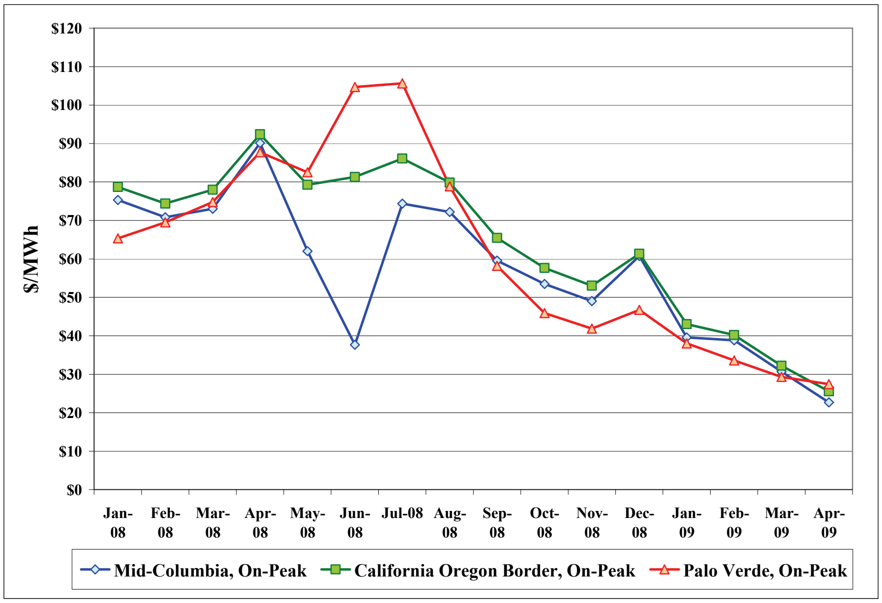
- An additional planning challenge has been to respond to and predict the demand response impacts of the economic recession and financial crisis. The Company is currently seeing a continuation of significant industrial and commercial sector demand destruction. This will translate into a reduction in resource need for the near-term. Nevertheless, the depth of the economic recession and the pace of a recovery are uncertain, complicating the resource requirements picture. The table below compares the Company's peak load forecasts prepared in November 2008 and February 2009 without reductions from energy efficiency programs, showing the differences through 2018. The February 2009 load forecast was prompted by a review of actual loads through January 2009.

Load Forecast	**Coincident Peak Load, Megawatts**									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
November 2008	10,150	10,371	10,640	10,991	11,281	11,501	11,798	12,127	12,384	12,674
February 2009	9,987	10,248	10,599	10,930	11,232	11,459	11,781	12,034	12,383	12,679
Difference	(163)	(123)	(41)	(61)	(49)	(42)	(17)	(93)	(1)	5

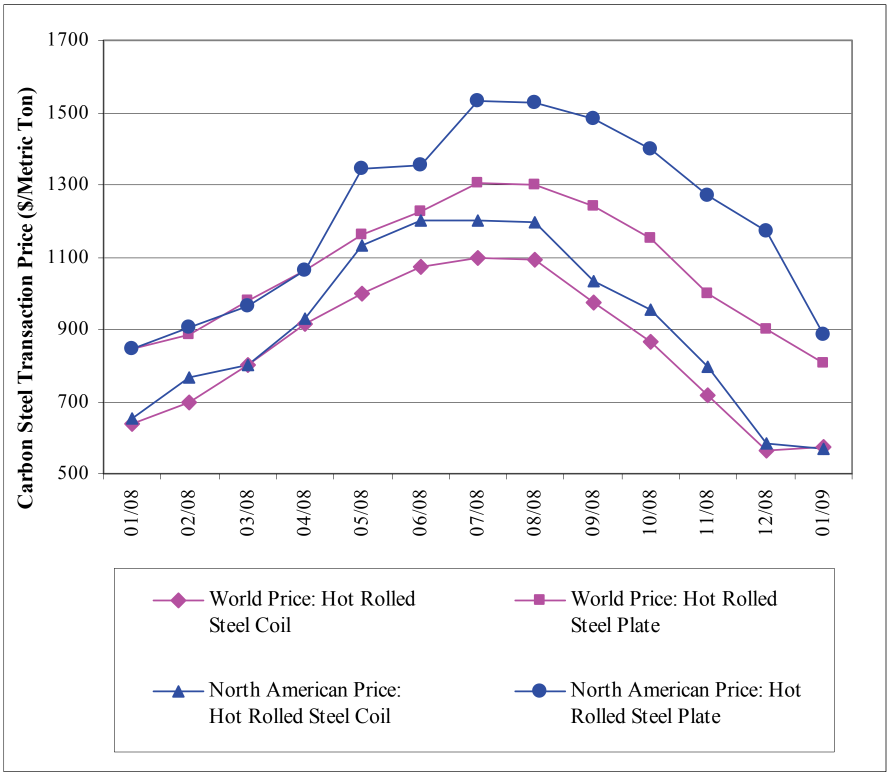
- At the same time, volatile economic conditions and commodity prices, combined with regulatory uncertainty, have complicated the planning picture, requiring the Company to continuously re-evaluate input assumptions and resource acquisition strategies throughout this planning cycle. For example the three charts below vividly illustrate the dramatic price movement of Henry Hub day-ahead natural gas prices, day-ahead wholesale electricity prices, and carbon steel prices during the time this IRP was developed.



Source: IntercontinentalExchange, OTC Day-ahead Index



Source: IntercontinentalExchange, OTC Day-ahead Prices



Source: MEPS (International) LTD, MEPS Steel Prices On-line

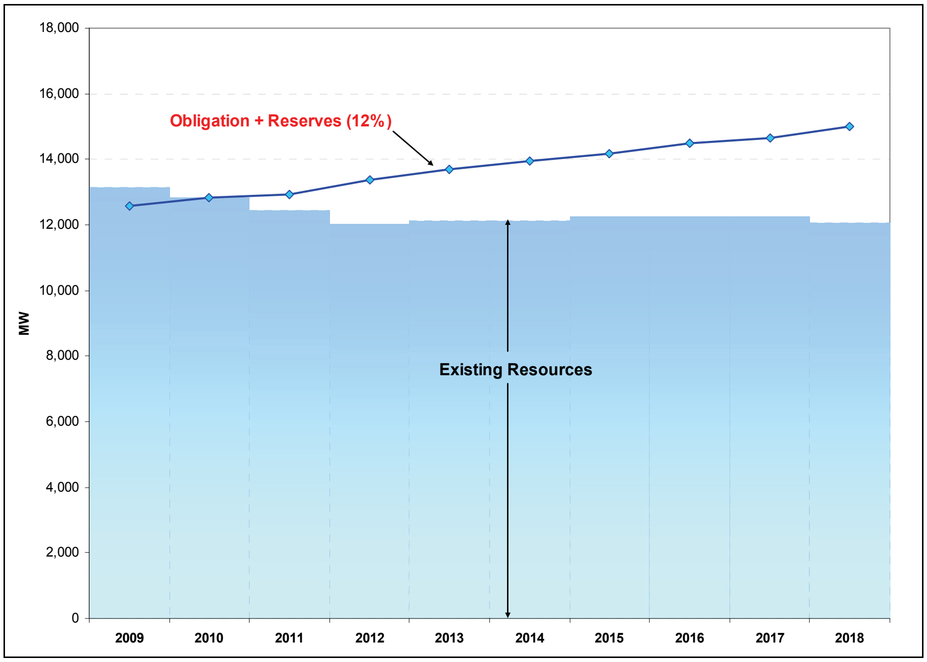
◆ The significant price drops in fuels and forward wholesale power in late 2008 and early 2009 signal near-term opportunities to lower power supply costs through market purchases before the Company needs to commit to a large new thermal power plant. If construction markets continue to soften as several experts predict, this will create additional cost-saving opportunities through lower plant prices.

- The 2008 IRP reflects evolution of PacifiCorp's corporate resource planning approach. In early 2008, PacifiCorp embarked on a strategy to more closely align IRP development activities and the annual 10-year business planning process. The purpose of the alignment was to adopt consistent planning assumptions, ensure that business planning is informed by the IRP portfolio analysis and that the IRP accounts for near-term resource affordability, and improve resource planning transparency for public stakeholders.

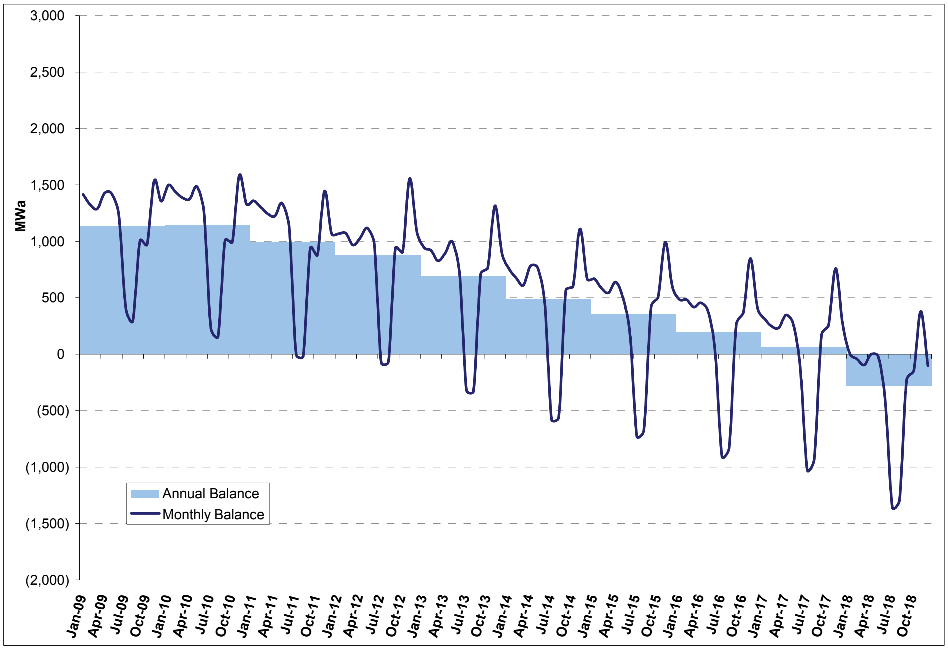
- PacifiCorp's 2008 IRP accounts for the Energy Gateway Transmission project. For the 2008 IRP cycle, the Company treated the various planned transmission segments as existing resources for portfolio modeling purposes. Going forward, Gateway transmission segments will be reevaluated from an integrated resource planning perspective during the IRP and annual business planning cycles.

RESOURCE NEEDS AND PORTFOLIO MODELING

- The resource need accounts for load growth, sales obligations, existing resources, and a 12 percent planning reserve margin. Based on a November 2008 load forecast, PacifiCorp experiences a capacity deficit beginning in 2011—the system is short by 498 megawatts (MW). This deficit increases to 1,936 MW in 2012 and 3,528 MW by 2018. The following chart shows the growth in the gap between resources and capacity, requirements based on a 12 percent capacity reserve requirement. The capacity deficit is driven by a coincident system peak load growth rate of 2.5 percent for 2009-2018, and expiration of major power contracts such as the Bonneville Power Administration peaking contract in August 2011.



On an energy basis, the system begins to experience summer short positions by 2012 as indicated in the following chart that shows the gap between available energy and load obligations.



- To determine how best to address the capacity deficits, PacifiCorp developed 57 resource portfolios using a capacity expansion model that optimizes resource choice according to a variety of input assumptions and capacity planning criteria. The Company simulated most of these portfolios—developed with a combination of carbon dioxide regulatory costs, forward electricity and natural gas prices, load forecast scenarios, and other variables—using a production cost model that accounts for stochastic variation in key variables. These stochastic variables include loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal resource availability.

- PacifiCorp's state utility commissions require the Company, through their IRP standards and guidelines, to develop a portfolio that is least-cost after accounting for risk, uncertainty, and the long-run public interest. To make this determination, PacifiCorp uses a wide range of portfolio performance measures that capture cost, risk, and supply reliability attributes. The Company focuses on seven measures and a weighted composite scoring scheme to isolate the top-performing portfolios. The three measures given the most weight for scoring purposes include the following:

    - Risk-adjusted Present Value of Revenue Requirements (45% weight)
    - Customer rate impact – the average annual change in the customer dollar-per-megawatt-hour price for the period 2010 through 2028 (20% weight)
    - Carbon dioxide cost exposure – reflects a portfolio's potential for avoiding worst-case cost outcomes given CO_2 regulatory cost uncertainty (15% weight)

PacifiCorp focused its final portfolio performance evaluation on the four portfolios with the best performance scores, comparing them on the basis of individual measure performance and considering other factors such as fuel source diversity and risks not captured in the portfolio modeling (for example, procurement and construction management risks).

THE 2008 IRP PREFERRED PORTFOLIO

- PacifiCorp's 2008 IRP preferred portfolio consists of a diverse mix of resources dominated by renewables, demand-side management, gas-fired resources, and firm market purchases. The major resources for the 2009-2018 planning period consist of the following:
  - Renewables:
    - Wind: 1,313 MW
    - Geothermal: 35 MW
    - Major hydroelectric upgrades: 75 MW in 2012-2014
  - Demand-side management
    - Energy efficiency: 904 MW
    - Dispatchable load control: 205 to 325 MW
  - Gas-fired capacity: 831 MW in the 2014-2016 period
  - Coal plant turbine upgrades: 170 MW of emissions-free capacity
  - Firm market purchases: Ranging from 50 MW to 1,400 MW on an annual basis, contingent on the timing and amounts of long-term resource acquisitions

The table below shows the incremental resource additions by year.

		Capacity, MW										Cumulative Total
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
East												
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-	200
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	128
	Geothermal	-	-	-	-	35	-	-	-	-	-	35
	Wind	99	249	-	100	100	100	150	100	100	50	1,048
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4	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	532
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800	
West												
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	42
	Swift Hydro Upgrades [2]	-	-	-	25	25	25	-	-	-	-	75
	Wind	45	20	200	-	-	-	-	-	-	-	265
	CHP	1	1	1	1	2	2	2	2	2	2	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	372
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582	

[1] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.

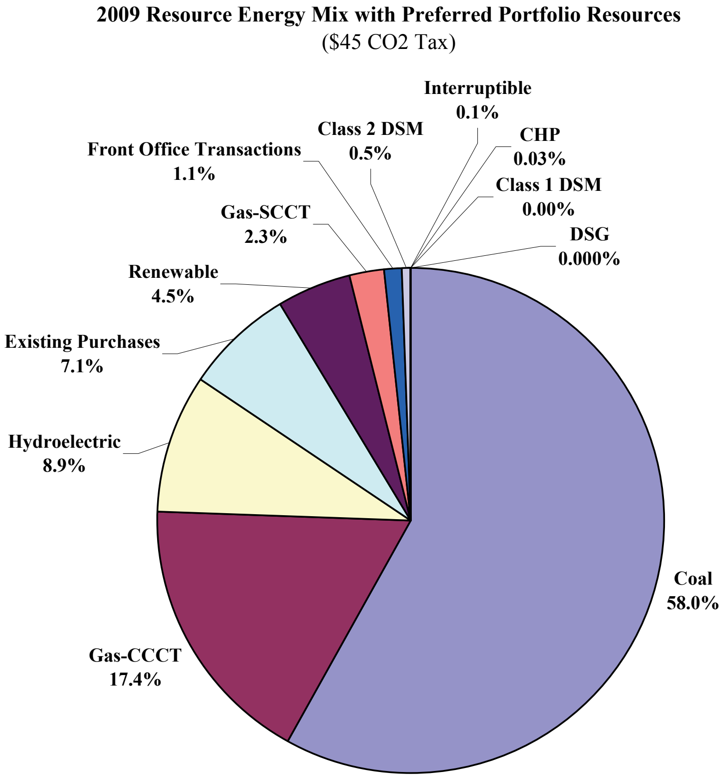
[2] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

- The capacity expansion model determined the amount and timing of renewables resources subject to annual system-wide renewable portfolio standard generation requirements established from existing state targets in place as of late 2008. PacifiCorp manually spread the wind resource quantities relatively evenly across all years of the 10-year business-planning period to support rate and capital spending stability, balance the timing risks associated with uncertain CO_2 costs and the possibility of federal renewable production tax credit expiration, among other benefits.

◆ PacifiCorp is on pace to exceed the previous renewable resource amount identified in the Company's 2007 Renewable Energy Action Plan filed in May 2007 (1,400 MW by 2015), and the amount identified in the 2007 IRP Update report filed in June 2008 (2,000 MW by 2013).[1] Since 2005, the Company's projected renewable resource inventory has grown by 1,404 MW, accounting for existing resources and those under construction, contract, or included in the capital budget. The incremental renewables identified in the 2008 IRP preferred portfolio and action plan bring the target to about 2,040 MW by 2013. The projected renewables inventory exceeds 2,540 MW by 2018, which represents 18.5% of PacifiCorp's owned generation capability in that year.

◆ The pie charts below show the resource generation mix in megawatt-hours for 2009 and 2018, assuming that a $45/ton CO_2 tax is in place beginning in 2013 with 2% annual inflation.



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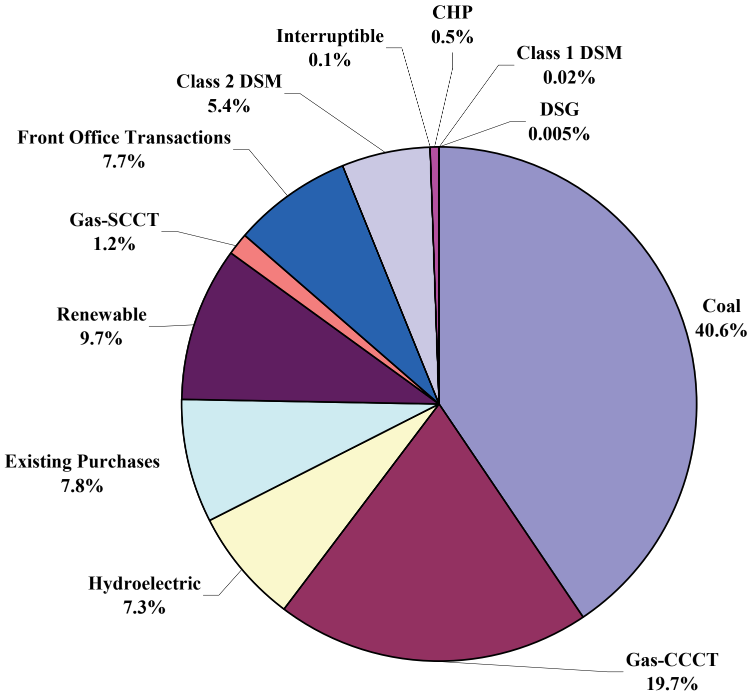
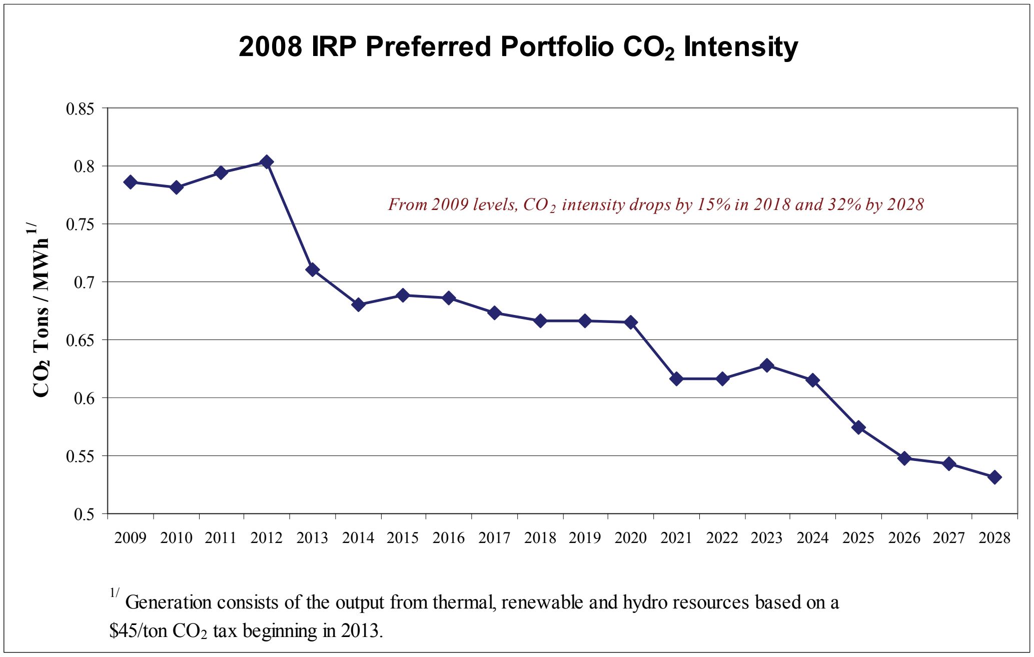
[1] Both of these documents are available at PacifiCorp's IRP Web site. The link to the Renewable Energy Action Plan is http://www.pacificorp.com/File/File74767.pdf. The link to the 2007 IRP Update is http://www.pacificorp.com/File/File82304.pdf.

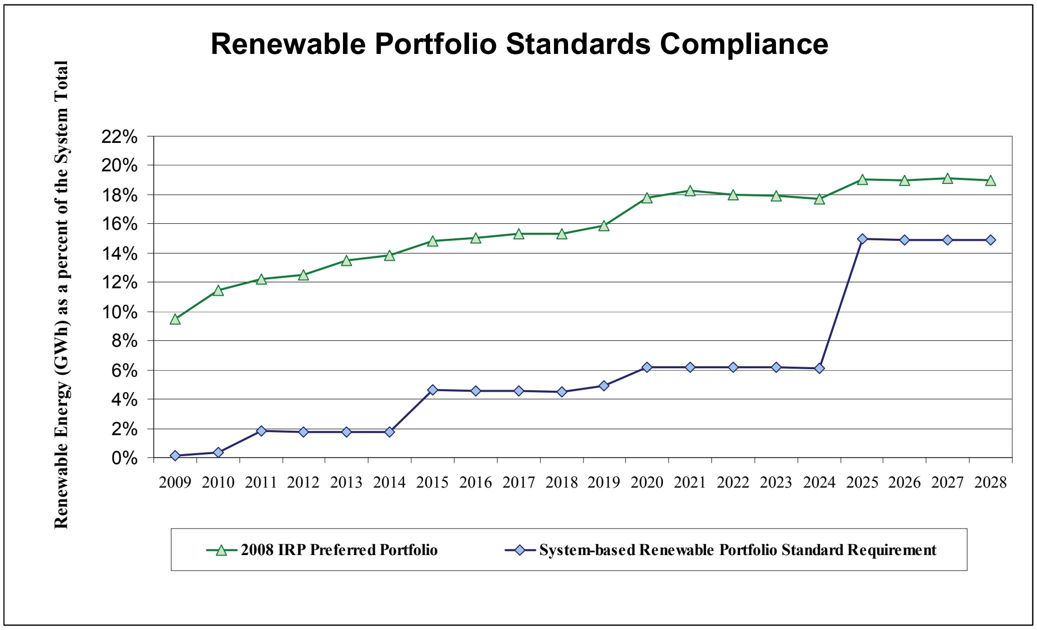
2018 Resource Energy Mix with Preferred Portfolio Resources
($45 CO2 Tax)



◆ The increasing mix of clean resources—renewables and demand-side management—reduces the carbon intensity of PacifiCorp's generation fleet and positions the Company well for meeting future climate change and renewable resource requirements. The following two charts show the declining trend in CO_2 emissions per MWh of generation, and how the preferred portfolio complies with existing jurisdictional renewable portfolio standards expressed as a percent of system load.



[1/] Generation consists of the output from thermal, renewable and hydro resources based on a $45/ton CO_2 tax beginning in 2013.



The addition of energy efficiency resources—reaching 4.2 million kWh by 2018—reduces the system coincident peak load from a 2.7% average annual growth rate (2009-2018) to 1.9%. The addition of flexible natural gas resources supports the aggressive expansion of intermittent renewable generation while meeting incremental base load and intermediate load needs. The role of new firm market purchases is to help replace expiring long-term power purchases, and, by adjusting volumes up or down, provide resource flexibility to manage the volatility and uncertainty in load forecasts, commodity prices, and capital costs.

◆ Relative to the preferred portfolio reported in the 2007 IRP Update report (June 2008), the 2008 preferred portfolio relies on significantly less firm market purchases for the period covered in common (2009-2017). For gas resources, the major difference is the addition of a simple-cycle gas plant in 2016; with the acquisition of the Chehalis plant in 2008, there is negligible change in the amount of combined-cycle gas capacity. The 2008 IRP relies more heavily on distributed generation resources, while differences in wind and Class 2 DSM are minimal. The following table shows the annual resource differences for the two preferred portfolios (2008 IRP less the 2007 IRP Update).

Resource Difference - 2008 IRP Preferred Portfolio less 2007 IRP Update

		Capacity, MW											**Total**
	Resource	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2008-2017**
East	Gas Combined Cycle (2x1)		-	-	-	(1,096)	-	570	-	-	-	-	(526)
	IC Aero SCCT		-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement		-	-	-	201	-	-	-	-	-	-	201
	Coal Plant Turbine Upgrades		(18)	7	(5)	(12)	2	14	-	8	-	-	(4)
	Geothermal, Blundell 3		-	(35)	-	-	35	-	-	-	-	-	-
	Wind	36 [2/]	(201)	149	(100)	(100)	100	(100)	150	100	100	50	134
	Distributed Generation		6	(13)	6	6	6	6	8	8	8	8	42
	Firm Market Purchases		75	50	150	279	(140)	(546)	(598)	(572)	(66)	800	NA
West	Chehalis CCCT	509 [2/]	-	-	-	-	-	-	-	-	-	-	509
	Coal Plant Turbine Upgrades		-	(8)	(9)	(5)	(5)	-	-	-	-	-	(28)
	Swift Hydro Upgrades*		-	-	-	-	-	-	-	-	-	-	-
	Wind	139 [2/]	45	20	-	-	(100)	-	-	-	-	-	104
	Distributed Generation		2	2	2	2	3	3	3	3	3	3	25
	Firm Market Purchases	(400)	(400)	(657)	(677)	(311)	30	(55)	(100)	(333)	(609)	582	NA
DSM [3/]	Energy Efficiency (Class 2 DSM)	(67)	2	2	(2)	(3)	1	2	3	2	5	87	(55)

[1/] Acquisition of the Chehalis 509 MW combined-cycle plant in Washington.

[2/] For 2008, actual wind additions totaled 545 MW, compared to the planned amount of 370 MW in the 2007 IRP Update

[3/] Expansions of the existing Utah Cool Keeper program and dispatchable irrigation programs are treated as existing resources. Relative to the 2007 IRP Update quantities, the incremental DSM planned expansions reach 525 MW by 2018.

[4/] For the 2007 IRP Update, Class 2 DSM was treated as a decrease to load rather than as a resource included in the preferred portfolio.

◆ Although the Company could not accommodate a comprehensive portfolio evaluation based on the February 2009 load forecast without contravening certain state IRP filing requirements, PacifiCorp was nevertheless able to conduct a preferred portfolio sensitivity analysis with it. Combining the February 2009 load forecast with the input assumptions from which the original preferred portfolio was derived, PacifiCorp developed an alternate portfolio using its the capacity expansion model.

  - A 2014 combined-cycle combustion turbine (CCCT) resource in the original preferred portfolio was fixed in that same year for the sensitivity analysis model run, owing to the small capacity deficits that ranged from 61 MW in 2012 to 93 MW in 2016.
  - The capacity expansion model determined that a 2016 intercooled aeroderivative SCCT was no longer needed, and that deferral and modest reductions in firm market purchases was cost-effective combined with an increase in customer standby generation and addition of utility-scale biomass resources.

◆ Since the relative resource impact of the February 2009 load forecast is minimal until 2016, PacifiCorp decided to retain the IC aero SCCT in the preferred portfolio. Also supporting this decision is the uncertainty over the timing and pace of an economy recovery, combined with the short lead-time for a gas peaking resource and the potential need for such resources to support wind integration. Consideration of the timing and type of gas resources and other resource changes will be handled as part of a comprehensive assumptions update and portfolio analysis to be conducted for the next business plan and 2008 IRP update.

THE 2008 IRP ACTION PLAN

- The 2008 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study completion. The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties. The current volatile economic and regulatory environment will likely require near-term alteration to resource plans as a response to specific events and improved clarity concerning the direction of the economy and government energy and environmental policies.

- Resource information used in the 2008 IRP, such as capital and operating costs, is consistent with that used to develop the Company's business plan completed in December 2008. However, it is important to recognize that the resources identified in the 2008 IRP preferred portfolio are proxy resources and act only as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

- The table below constitutes PacifiCorp's 2008 IRP action plan.

2008 IRP Action Plan

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	2009 - 2018	Acquire an incremental 1,400 MW of renewables by 2018, in addition to the already planned 75 MW of major hydroelectric upgrades in 2012-2014; PacifiCorp's projected renewable resource inventory by 2018 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 269 MW of wind resources in 2010 that are currently in the project pipeline, 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 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 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 solar and emerging technologies, government financial incentives, and procure 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 at the state and federal levels, and adjust the renewable acquisition timeline accordingly*
2	Firm Market Purchases	2009 - 2013	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until no sooner than the beginning of summer 2014 • Acquire the following resources: – Up to 1,400 MW of economic front office transactions on an annual basis as needed through 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) • Resources will be procured through multiple means: (1) reactivation of the suspended 2008 All-Source RFP in late 2009, which seeks third quarter summer products and customer physical curtailment

Action Item	Category	Timing	Action(s)
			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 2009 load forecast • *Acquire incremental transmission through Transmission Service Requests to support resource acquisition*
3	Peaking / Intermediate / Base-load Supply-side Resources	2012 - 2016	Procure long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame • 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 in late 2009 – The Company plans to submit Company resources (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.*
4	Plant Efficiency Improvements	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 2016, which are expected to add 128 MW of incremental in the east and 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*[2] • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules*
5	Class 1 DSM	2009-2018	Acquire at least 200 - 300 MW of cost-effective Class 1 demand-side management programs for implementation in the 2009-2018 time frame • *Pursue up to 200 MW of expanded Utah Cool Keeper program participation by 2018* • *Pursue up to 130 MW of additional cost-effective class 1 DSM products(90 MW in the east side and 30 MW in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound*

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

Action Item	Category	Timing	Action(s)
			in load growth resulting from economic recovery Procure through the currently active 2008 DSM RFP and subsequent DSM RFPs • For 2009-2010, 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.
6	Class 2 DSM	2009-2018	Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa • *Procure through the currently active DSM RFP and subsequent DSM RFPs*
7	Class 3 DSM	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*
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 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
9	Planning Process Improvements	2009-2010	Portfolio modeling improvements • Complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level

Action Item	Category	Timing	Action(s)
			• 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 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 • Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for 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
10	Transmission	2009-2011	Obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona To 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
11	Transmission	2010	Permit and build Utah/Idaho/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Permit and construct a 345 kV line between Populus to Terminal
12	Transmission	2012	*Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Mona and Oquirrh*

Action Item	Category	Timing	Action(s)
13	Transmission	2014	*Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct 230 kV and 500 kV line between Windstar and Populus* • *Permit and construct a 345 kV line between Sigurd and Red Butte*
14	Transmission	2016	*Permit and build Northwest/Utah/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Populus and Hemingway*
15	Transmission	2017	*Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Aeolus and Mona*

2. INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP, representing the 10th plan submitted, fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties.

This IRP also builds on PacifiCorp's prior resource planning efforts and reflects continued advancements in portfolio modeling and performance assessment. These advancements include (1) extensive expansion of resource options considered, (2) a wider range of portfolios developed with alternative input assumptions using the Company's capacity expansion optimization tool, (3) more detailed presentation of renewable portfolio standard compliance requirements, and (4) adoption of a portfolio preference scoring methodology that incorporates probability-weighting of CO_2 cost futures and importance weighting of various portfolio performance measures. The portfolio preference scoring methodology explicitly incorporates CO_2 risk into the portfolio selection decision, and structures the key performance measures into a composite ranking system that shows, in a transparent fashion, how PacifiCorp chose the optimal resource plan among several alternatives.

Finally, this IRP reflects evolution of PacifiCorp's corporate resource planning approach. In early 2008, PacifiCorp embarked on a strategy to more closely align IRP development activities and the annual 10-year business planning process. The purpose of the alignment was to:

- provide corporate benefits in the form of consistent planning assumptions,
- ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns that are the province of capital budgeting, and;
- improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

The planning alignment strategy also follows the 2007 adoption of the IRP portfolio modeling and analysis approach for Requests for Proposals (RFP) bid evaluation.[3] This latter initiative was part of PacifiCorp's effort to unify planning and procurement under the same analytical framework.

This chapter outlines the components of the 2008 IRP, summarizes the role of the IRP, describes the IRP/business plan alignment strategy and progress to date, and provides an overview of the public process.

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[3] For its 2012 Base Load RFP, PacifiCorp used the IRP Monte Carlo production cost simulation model to evaluate costs and risks of portfolios with bid resources optimized with different input assumptions (CO_2 cost, fuel prices, and planning reserve margins).

2008 INTEGRATED RESOURCE PLAN COMPONENTS

The basic components of PacifiCorp's 2008 IRP, and where they are addressed in this report, are outlined below.

- The set of IRP principles and objectives that the Company adopted for this IRP effort, as well as a discussion on customer/investor risk allocation (this chapter).

- An assessment of the planning environment, including PacifiCorp's 2009 business plan—developed in 2008 and approved by MidAmerican Energy Holdings Company (MEHC) board of directors in December 2008, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).

- A description of PacifiCorp's transmission planning effort and its linkages to the integrated resource planning effort (Chapter 4).

- A resource needs assessment covering the Company's load forecast, status of existing resources, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 5).

- A profile of the resource options considered for addressing future capacity deficits (Chapter 6).

- A description of the IRP modeling, risk analysis, and portfolio performance ranking processes (Chapter 7).

- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio (Chapter 8)

- An IRP action plan linking the Company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource risks (Chapter 9)

- PacifiCorp's transmission expansion action plan, focusing on the Energy Gateway Transmission project (Chapter 10)

The IRP appendices, included as a separate volume, comprise detailed IRP modeling results (Appendices A and B), fulfillment of IRP regulatory compliance requirements, (Appendix C), the public input process (Appendix D), additional load forecast information (Appendix E), the results of PacifiCorp's wind integration cost study (Appendix F), energy efficiency program avoided cost estimates (Appendix G), and additional load and resource balance information pertaining to the Lake Side II combined-cycle gas plant (Appendix H).

THE ROLE OF PACIFICORP'S INTEGRATED RESOURCE PLANNING

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[4] The main role of the IRP is to serve as a roadmap for determining and implementing the Company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting Request for Proposals (RFP) bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

ALIGNMENT OF PACIFICORP'S IRP AND BUSINESS PLANNING PROCESSES

Alignment Strategy Overview

The alignment strategy consists of the following four elements:

- **Scheduling synchronization** – PacifiCorp modified its IRP preparation schedule to accommodate business plan preparation beginning in March 2008 and ending in late November 2008, culminating with plan approval in mid-December 2008 by the MidAmerican Energy Holdings Company (MEHC) board of directors.

- **Input assumption synchronization** – The IRP models are updated on a real-time basis as changes to business plan assumptions occur. These changes include, but are not limited to, revised load forecasts, forward price curves, resource costs, and environmental compliance policy assumptions. Public stakeholders are updated on major changes to input assumptions.

- **IRP modeling support for business plan development** – For each business planning scenario[5], PacifiCorp conducts IRP modeling to produce a resource portfolio for capital budget-

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

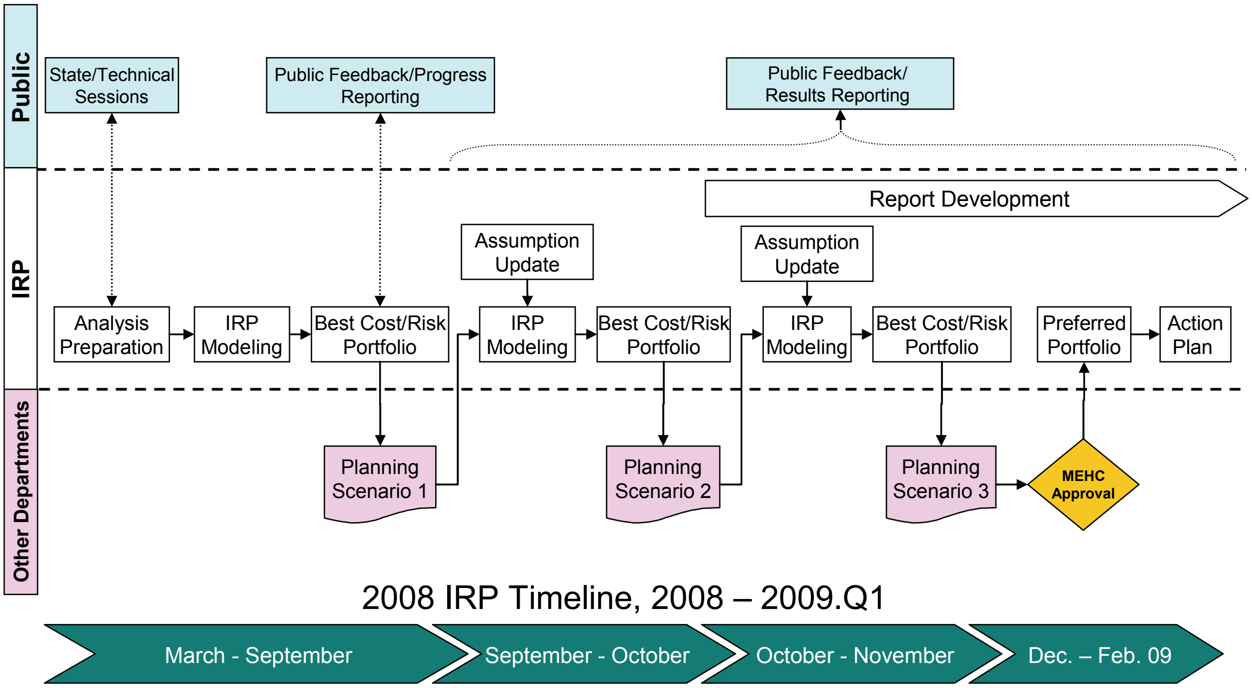
[5] A business planning scenario represents a unique set of assumptions for producing a planning outcome and associated financial results for a 10-year period. The business planning schedule accounts for preparation of three scenarios. Typically, the goal of each successive scenario is to (1) improve customer service and operational and financial results by optimizing operational expenditures and capital investments in accordance with the Company's business strategy, and (2) incorporate updated assumptions into the business planning process. Each planning scenario requires a complete processing cycle, including input collection and aggregation, tax estimation, cash-flow optimization through debt issuance and equity investment, quality assurance, and management review.

The key product for each planning scenario is a documentation package that describes the planning assumptions and contains a set of pro-forma financial statements conveying the financial impacts of the planning assumptions. PacifiCorp submits each planning scenario to MidAmerican Energy Holdings Company for review and approval on pre-established dates. At the end of the year, after the business plan receives MEHC board approval, high-level business planning information is provided in filings as required by state and federal regulations. Certain information ing and rate impact analysis by the corporate finance department. In an iterative process, resource constraints are applied to the portfolio optimization modeling to ensure that subsequent portfolios are deemed affordable and financeable by senior management.

- **Public process** – Through public meetings or other communication methods, the Company's IRP public participants are updated on significant business planning events. The relationship between the business plan and IRP preferred portfolios are documented in the IRP action plan.

Figure 2.1 is a process flow diagram that shows the relationship between IRP activities, business plan preparation, and the public process originally envisioned for the 2008 IRP development cycle.

Figure 2.1 – IRP/Business Plan Process Flow



Planning Process Alignment Challenges

A key challenge for the alignment was to reconcile the different planning perspectives associated with the two-year IRP development cycle and the annual corporate business planning cycle. As mentioned above, the IRP is a strategic planning roadmap focused on the long-term costs and risks of resource portfolios, accounting for uncertainty. In contrast, PacifiCorp's business plan focuses on maintaining a strong financial position while ensuring customer's generation needs are met economically given the expected operating environment. Central to this business planning goal is an emphasis on acquiring and managing the Company's assets to smooth the cost

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is also released on a confidential basis to various rating agencies and in certain regulatory dockets or other venues where necessary.

impacts for customers. Successful alignment of the two planning processes thus entails balancing these perspectives as resource decisions are made.

Another key challenge for the planning process alignment was to accommodate the preparation timing differences and analytical requirements for the two planning processes. The 10-year business plan is an annual process that entails frequent input assumption updates and preparation of multiple versions of the plan for internal prudence reviews. On the other hand, the IRP is a biennial planning process requiring extensive upfront model preparation, a public input process, and completion of specific analytical tasks cited in the state's IRP standards and guidelines and IRP acknowledgment orders. Meshing the planning processes entails significantly more departmental coordination, along with an acceleration of the IRP modeling workflow to start portfolio development two to three months earlier than is typically done for the IRP.

A final key challenge was to provide modeling support for both the IRP and business plan while at the same time implementing major modeling enhancements. These enhancements included (1) unbundling Class 2 demand-side management programs (energy efficiency) from the load forecasts and instituting a Class 2 DSM supply curve modeling approach, (2) expansion of resource options to include wind with different resource qualities, additional renewable technologies, energy storage, nuclear, distributed generation, fuel cells, and additional front office transaction product types, (3) improvements in modeling renewable portfolio standard (RPS) requirements, (4) computer and network infrastructure upgrades, and (5) a major upgrade of the Planning and Risk production cost model.

Given these challenges, the expectation was that the alignment would be conducted over a two-year span.

Alignment Strategy Progress

PacifiCorp successfully implemented all the planned IRP modeling system improvements, and maintained input consistency with business plan assumptions throughout the planning cycle. Importantly, the business plan benefited from implementation of the DSM class 2 supply curves, providing for the first time energy efficiency program targets based on integrated resource portfolio modeling with these resource options included. PacifiCorp also successfully provided an optimized resource portfolio for each business planning scenario.

However, two alignment strategy objectives were not met. For the business plan, PacifiCorp originally intended to conduct alternative portfolio development with different input assumptions (basically a subset of the input scenarios defined for the IRP), and run Monte Carlo production cost simulations to compare portfolio stochastic costs and risks. Additionally, public reporting goals on the progress of business plan preparation could not be accommodated in the schedule. There were two reasons for not meeting these objectives. First, business plan portfolio optimization modeling required frequent updates in reaction to volatile energy markets, the financial market crisis, a deteriorating load growth outlook, and continued resource cost increases. This caused a delay of the start of IRP modeling, while the turnaround time for business plan modeling precluded establishment of a meaningful public comment and response process. Second, the modeling enhancements and system upgrades—particularly for the Planning and Risk model—took longer than expected.

As a consequence of the IRP modeling delay, the business plan was approved by the MEHC board of directors in December 2008—prior to the completion of IRP modeling and selection of the 2008 IRP preferred portfolio. In accordance with the alignment strategy, the major resource changes relative to the business plan were analyzed for financial and ratepayer impact by the PacifiCorp Energy Finance Department. Major differences between the business plan resources and the 2008 IRP preferred portfolio are described in Chapters 8 and 9.

PUBLIC PROCESS

The IRP standards and guidelines for certain states require PacifiCorp have a public process allowing stakeholder involvement in all phases of plan development. The Company held 17 public meetings/conference calls during 2008 and early 2009 designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public meetings/conferences and major agenda items covered.

Table 2.1 – 2008 IRP Public Meetings

Meeting Type	Date	Main Agenda Items
General Meeting	2/29/2008	2008 IRP modeling plan, business planning process, 2007 IRP Update
State Stakeholder Input	4/9/2008	Utah stakeholder comments
State Stakeholder Input	4/10/2008	Wyoming stakeholder comments
State Stakeholder Input	4/21/2008	Oregon and California stakeholder comments
State Stakeholder Input	4/22/2008	Washington stakeholder comments
State Stakeholder Input	4/23/2008	Idaho stakeholder comments
State Stakeholder Input	5/14/2008	Utah stakeholder comments
General Meeting	5/22/2008	Input scenario ("case") definitions, resource characterization
Workshop	5/23/2008	CO_2 costs and modeling, EPRI CO_2 study results
Workshop	6/26/2008	Load forecasting methodology, preliminary load forecast
General Meeting	11/12/2008	Load forecast update, IRP/Business plan alignment, IRP status (conf. call)
General Meeting	12/18/2008	Load forecast update, portfolio development results, load & resource balance
General Meeting	1/7/2009	Repeat of 12/18/2008 agenda for Washington and Idaho stakeholders
General Meeting	2/2/2009	Stochastic modeling results, portfolio performance, preferred portfolio
General Meeting	3/11/2009	IRP status and state commission filing update (conference call)
State Stakeholder	3/19/2009	Utah state commission filing schedule for IRP (conference call)

New for this IRP was a series of state stakeholder dialogue sessions conducted from April through May 2008. The purpose of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. This change in public process was intended to enhance interaction with stakeholders early on in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during general public meetings.

Appendix D, in the separate appendix volume, provides more details concerning the public meeting process and individual meetings.

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

MIDAMERICAN ENERGY HOLDINGS COMPANY IRP COMMITMENTS

MEHC and PacifiCorp committed to continue to produce IRPs according to the schedule and various state commission rules and orders at the time the transaction was in process. Other commitments were made to (1) encourage stakeholders to participate in the integrated resource planning process and consider transmission upgrades, (2) develop a plan to achieve renewable resource commitments, (3) consider utilization of advanced coal-fuel technology such as IGCC technology when adding coal-fueled generation, (4) conduct a market potential study of additional demand-side management and energy efficiency opportunities, (5) evaluate expansion of the Blundell Geothermal resource, and (6) include utility "own/operate" resources as a benchmark in future request for proposals. The Transaction Commitments Annual Report for 2009 is in progress and due to be filed with each Commission on Friday, May 29, 2009.

3. THE PLANNING ENVIRONMENT

INTRODUCTION

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

A key resource planning consideration has been the faltering U.S. economy and tightening of credit markets. Changing economic circumstances have required the Company to continuously re-evaluate and adjust load growth and market price expectations throughout this planning cycle, a process mentioned in the previous chapter in the context of 2009 business plan preparation. For capital expenditure planning, the Company's challenge has been to minimize customer rate impacts in light of a substantial capital spending requirement needed to address customer load growth, support government environmental and energy policies, and maintain transmission grid reliability. To address this challenge, PacifiCorp is scrutinizing capital projects for cost reductions or deferrals that make economic sense in today's market environment. Along these lines, the Company recently decided to seek more cost-effective alternatives to the planned Lake Side II combined-cycle gas plant project in Utah. The implications of this resource decision for the IRP are addressed in this chapter.

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

On the government policy and regulatory front, the largest issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the Company's greenhouse gas emissions mitigation strategy, as well as an overview of the Electric Power Research Institute's study on carbon dioxide price impacts on western power markets, follows. This chapter also reviews the significant policy developments for currently-regulated pollutants

Other topics covered in this chapter include the Energy Independence and Security Act of 2007, the status of renewable portfolio standards, hydroelectric licensing, and resource procurement activities.

IMPACT OF THE 2012 COMBINED-CYCLE GAS PLANT PROJECT TERMINATION

In February 2009, PacifiCorp decided to terminate the construction contract for the Lake Side II combined-cycle plant, which was planned to be in commercial operation by the summer of 2012. The decision to seek other resource alternatives was driven by the worsening recessionary environment, declines in load growth, continued declines in forward electricity and gas prices, the outlook for future plant construction costs, and additional transmission import capability into Utah confirmed with recently completed transmission studies. The construction termination decision occurred after initial selection of the 2008 IRP preferred portfolio, but before finalization of the IRP document and preparation of the IRP action plan. Consequently, PacifiCorp decided to conduct additional portfolio analysis to determine the impacts of excluding Lake Side II as a planned resource in 2012, and then update the preferred portfolio and develop the action plan accordingly. This analysis consisted of the following five steps:

- Revise the load and resource balance to reflect the absence of the Lake Side II CCCT plant in 2012 (shown in Chapter 5).
- Update the IRP models with new transmission and market purchase availability information that can facilitate cost-effective alternatives to a single large 2012 resource addition (described in Chapter 6).
- Use the Company's capacity expansion optimization model to develop a set of alternative portfolios without the Lake Side II plant, applying the same input scenarios ("cases") that yielded the top-performing portfolios in PacifiCorp's original portfolio analysis. (This portfolio development is summarized in Chapter 8.)
- Conduct stochastic Monte Carlo production cost simulation of the alternative portfolios, and determine the new preferred portfolio with the support of the portfolio preference scoring methodology adopted for this IRP. (The portfolio performance evaluation is described in Chapter 8.)
- Include the findings of the portfolio analysis in the IRP action plan and supporting acquisition path analysis.

WHOLESALE ELECTRICITY MARKETS

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

PacifiCorp participates in the wholesale market in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to efficiently match delivery patterns to the profile of customer demand. The market is not without its risks, as the experience of the 2000-2001 market crisis, followed by the rapid price escalation during the first half of 2008 and subsequent demand destruction and rapid price declines in the second half of 2008, have underscored.

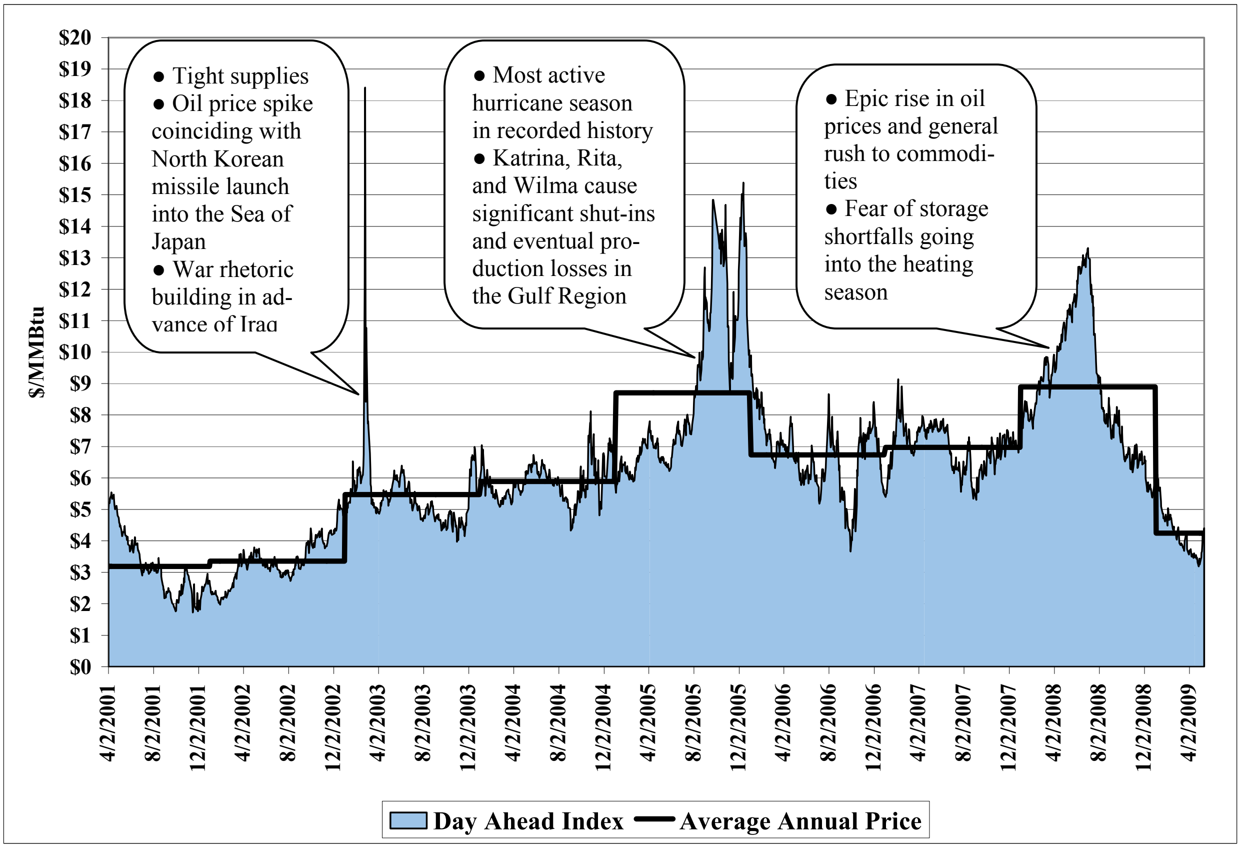
As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, the Western Electricity Coordinating Council (WECC) publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. The latest WECC power supply assessment, published in November 2008, indicates that the Basin and Rockies sub-regions will be resource deficit, after accounting for reserves, by 2011. (It should be noted that this assessment does not account for the recent recessionary impacts on load growth and various utilities' resource plans.)

There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices. Given the increased role of natural gas-fired generation, gas prices have become a critical determinant in establishing western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on this IRP is the prospect of future green house gas policy. A broad landscape of federal, regional, and state proposals aiming to curb green house gas emissions continues to widen the range of plausible future energy costs, and consequently, future electricity prices. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

Natural Gas Uncertainty

Over the last eight years, North American natural gas markets have demonstrated exceptional price escalation and volatility. Figure 3.1 shows historical day-ahead prices at the Henry Hub benchmark from April 2, 2002 through February 3, 2009. Over this period, day-ahead gas prices settled at a low of $1.72 per MMBtu on November 16, 2001 and at a high of $18.41 per MMBtu on February 25, 2003. During the fall and early winter of 2005, prices breached $15 per MMBtu after a wave of hurricanes devastated the gulf region in what turned out to be the most active hurricane season in recorded history. More recently, prices topped $13 per MMBtu in the summer of 2008 when oil prices began their epic climb above $140 per barrel. During this period, the natural gas market was also concerned that declining imports and slow growth in domestic production would create a storage shortfall going into the heating season. However, as the year progressed, it became increasingly evident that gains in unconventional supply was growing at an unprecedented pace, quelling fears of an unbalanced market. At the same time, the market began accounting for sharp declines in demand as the financial crisis evolved into a full-scale global recession. Consequently, prices retreated just as quickly as they rose.

Figure 3.1 – Henry Hub Day-ahead Natural Gas Price History



- Tight supplies
- Oil price spike coinciding with North Korean missile launch into the Sea of Japan
- War rhetoric building in advance of Iraq

- Most active hurricane season in recorded history
- Katrina, Rita, and Wilma cause significant shut-ins and eventual production losses in the Gulf Region

- Epic rise in oil prices and general rush to commodities
- Fear of storage shortfalls going into the heating season

Source: IntercontinentalExchange (ICE), Over the Counter Day-ahead Index

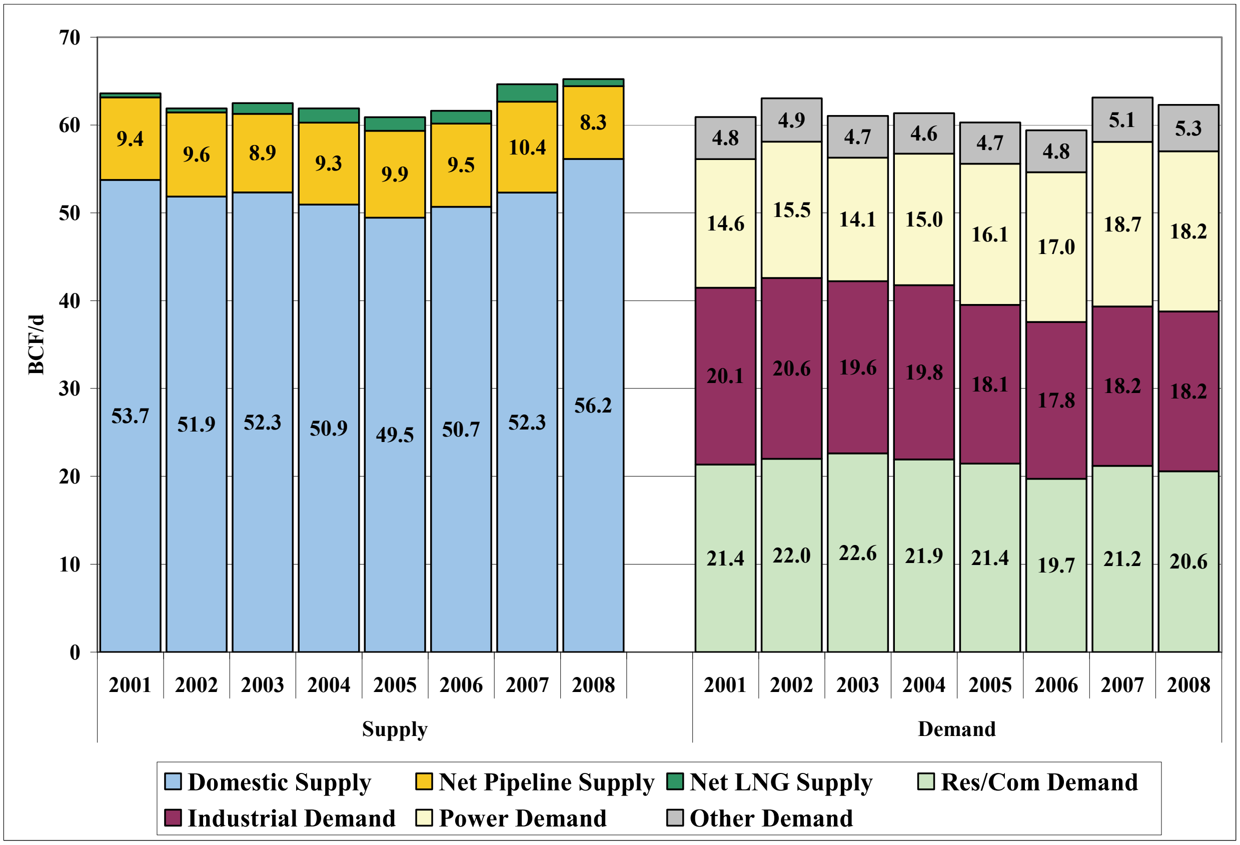
Beyond the geopolitical, extreme weather, and economic events that spawned some rather spectacular highs in the recent past, natural gas prices have exhibited an underlying upward trend from approximately $3 per MMBtu in 2002 to nearly $7 per MMBtu by 2007. Over much of this period, declining volumes from conventional, mature producing regions largely offset growth from unconventional resources. Figure 3.2 shows a breakdown of U.S. supply alongside natural gas demand by end-use sector.

Total supply, led by declines in domestic production, dropped steadily from 2001 through 2005. While total supply posted modest gains in 2006 and 2007, domestic production remained below the levels recorded in 2001. On the demand side, substantial expansion of gas-fired generating resources had more than offset declines in industrial demand for natural gas. This shift reduced the amount of industrial demand that is most price-elastic and increased inelastic generation demand. With higher finding and development costs of unconventional resources, the price level necessary to stimulate such marginal supply had grown. Until the recent economic downturn, substantial oil price escalation also supported higher natural gas prices, lifting the price of marginally competitive gas substitutes and the value of natural gas liquids.

Combined, the above factors contributed to a pronounced supply/demand imbalance in North American natural gas markets, raising prices sufficiently high to discourage marginal demand and, at times, attracting imports from an equally tight global market. This imbalance also made

North American markets more susceptible to upset from weather and other event shocks such as those discussed earlier.

Figure 3.2 – U.S. Natural Gas Balance History



Source: U.S. Department of Energy, Energy Information Administration

The supply/demand balance began to shift in 2007 and 2008 thanks to an unprecedented and unexpected burst of growth from unconventional domestic supplies across the lower 48 states. With rapid advancements in horizontal drilling and hydraulic fracturing technologies, producers began drilling in geologic formations such as shale. Some of the most prominent contributors to the rapid growth in unconventional natural gas production have been the Barnett Shale located beneath the city of Forth Worth, Texas and the Woodford Shale located in Oklahoma. Strong growth also continued in the Rocky Mountain region.

Looking forward, many forecasters have been expecting that a gradual restoration of improved supply/demand balance would be achieved largely with growth in liquefied natural gas (LNG) imports. Indeed, there has been tremendous growth in global liquefaction facilities located in major producing regions, and additional projects are expected to come online in 2009 and 2010. Concurrently, U.S. regasification capacity has grown to overbuild proportions. As of the end of 2008 U.S. regasification capacity was 4.7 times larger than the 1.98 BCF/d of LNG imports logged in 2007, and additional capacity is scheduled to go online in 2009 and 2010. Even with substantial gains in global LNG supplies and in domestic regasification capacity, the North

American market has not been able to consistently lure shipments from Asian and European markets, where gas prices are more directly linked to the price of oil.

With the recent expansion of unconventional production and the evolution of global LNG markets, many forecasters and market participants are beginning to reassess how mid- to long-term markets will balance. For example, the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) from 2007 forecasted that LNG imports would top 8 BCF/d by 2015. In the early look of AEO 2009 released in December 2008, the EIA expects 2015 LNG imports to total 3.4 BCF/d – just 41 percent of the LNG imports projected two years earlier. Beyond the near-term, where demand is being depressed by the current economic downturn, it is increasingly believed that unconventional supplies from North America are poised to meet incremental demand upon economic recovery. Under such a scenario, North American gas prices would remain decoupled from the global LNG market, and consequently decoupled from Asian and European natural gas markets, which are more heavily influenced by the price of oil.

Several factors contribute to a wide range of price uncertainty in the mid- to long-term. On the downside, technological advancements underlying the recent expansion of unconventional supplies opens the door to tremendous growth potential in both production and proven reserves from shale formations across North America. A number of shale formations outside of the Barnett and Woodford have already started to show upside potential. A sign of the times, the proposed Kitimat regasification terminal in British Columbia, Canada announced that the project was being redesigned as a liquefaction terminal apparently due to interest in the Horn River and Motney shale formations within the province. On the upside, the next generation of unconventional supplies may prove to be more difficult to extract, raising costs, and consequently, raising prices. Moreover, a concerted U.S. policy effort to shift the transportation sector away from oil toward natural gas has potential to significantly increase demand, and thus natural gas prices.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices. Although Rocky Mountain region production, among the fastest growing in North America, has caused prices at the Opal and Cheyenne hubs to transact at a discount to the Henry Hub benchmark in recent years, major pipeline expansions to the mid-west and east coupled with further pipeline expansion plans to the west are expected to maintain market price correlations going forward. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to other hubs in the region. This has been driven in large part by declines in Canadian natural gas production and reduced imports into the U.S. In the near-term, Canadian imports from British Columbia are expected to remain below historical levels lending support for basis differentials in the region; however, in the mid- to long-term, production potential from regional shale formations will have the opportunity to soften the Sumas basis.

Greenhouse Gas Policy Uncertainty

There is a wide range of policy proposals to limit greenhouse gas emissions within the U.S. economy. At the federal level, Senators Bingaman and Specter sponsored the Low Carbon Economy Act of 2007 (the Bingaman Bill), and more recently, Senators Lieberman and Warner introduced the Climate Security Act of 2008 (the Lieberman Warner Bill), while Representatives Waxman and Markey introduced the American Clean Energy and Security Act of 2009 (H.R.

2454). While it remains unclear what types of federal proposals will be debated going forward, there have been clear signals that the Obama administration has more of an appetite than the previous administration to address the climate change issue. At the state and regional level, the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program to restrict carbon dioxide emissions in Northeastern and Mid-Atlantic states, took affect in 2008. A similar approach is being explored in the Midwest under the Midwest Greenhouse Gas Accord. In the West, the Western Climate Initiative continues its work toward establishing rules for its own cap-and-trade program. Additional details on greenhouse gas policy developments are discussed later in this chapter.

As the policy debate continues, a cloud of uncertainty continues to hang over the electric sector, with substantial implications for investment decisions and wholesale electricity markets. There are a host of uncertainties stemming from the policy debate:

- If emission limits are put in place, will they cover the entire U.S. economy or will they target specific sectors?
- Will emission reductions be achieved through a cap-and-trade approach, through a carbon tax, or some combination of the two?
- What role, if any, will domestic and international offsets play in achieving emission reductions in the U.S.?
- Will emission reductions be achieved through a national program that preempts state and regional initiatives, will there be a more Balkanized approach, or will there be a national program layered on top of state and regional initiatives?
- How will renewable portfolio standards be coordinated or integrated with emission reduction regulations?

Regardless of how the policy debate unfolds, one thing remains clear. If limits are placed on greenhouse gas emissions, it is highly probable that the electric sector will be required to reduce emissions, and these emission reductions will come with a cost. Whether the costs are directly assessed in the form of a tax or are indicative of opportunity costs monetized in a market developed under a cap-and-trade program, all else equal, the cost to produce electricity will increase, and wholesale prices will respond. The projected cost of greenhouse gas emission reductions are intrinsically tied to policy details and vary considerably. Even for a given policy, there are a wide range of future cost estimates driven by long-term assumptions such as electricity demand, technological advancements, and varying interpretations of policy implementation rules. For example, in the December 17, 2008 auction for RGGI carbon dioxide emission allowances, prices cleared at \$3.38/ton. In contrast, the Energy Information Administration's (EIA) analysis of the Lieberman Warner Bill projected nominal allowance prices by 2030 ranging from nearly \$35/ton to approximately \$275/ton, while the U.S. Environmental Protection Agency's preliminary study of the Waxman-Markey Bill cited a scenario CO_2 cost range per metric ton of \$17 to \$33 by 2020.[6]

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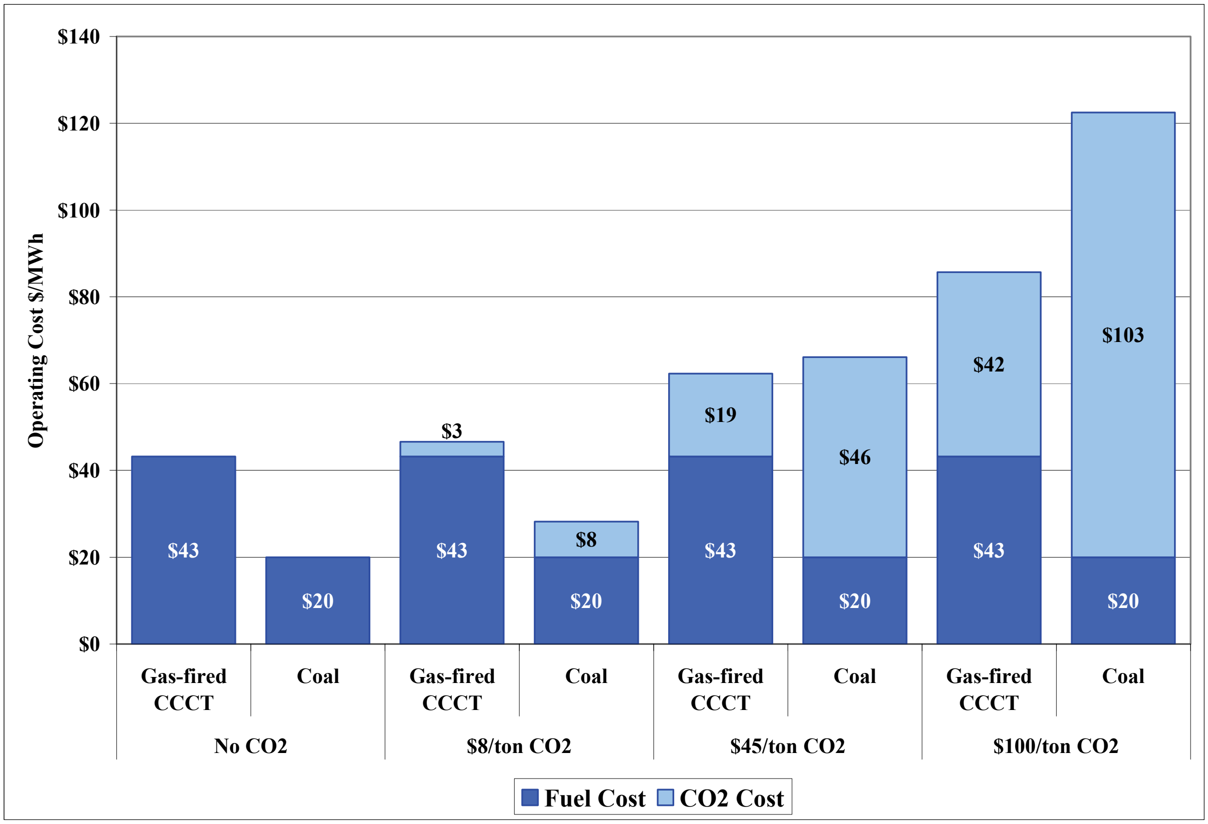
[6] A discussion draft of the EPA study is available at: http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf. The discussion draft notes that are remaining legislative uncertainties that could significantly change study results, and that the study represents limited coverage of bill provisions.

When a cost is placed on greenhouse gas emissions, it effectively becomes an additional variable cost facing an electric generator, and in much the same way that fuel costs affect plant dispatch decisions, emission costs influence how a plant operates. Because electric generators burn different types of fuel, have varying levels of efficiency, and are bound by different operational limitations, the impact of incremental green house gas costs varies across different types of technologies. To understand how green house gas emission costs will discriminately affect electricity markets, one can consider a simplified representation of the power system – a system that includes two types of resources: (1) a coal-fired plant, and (2) a gas-fired combined cycle plant.

Coal-fired assets, with limited operational flexibility and access to relatively low cost fuel, tend run around the clock. This type of base load capacity is often used to satisfy demand even when it is quite low. On the other hand, while natural gas-fired combined cycle assets typically have an efficiency advantage relative to a coal plant, they are often faced with higher fuel costs and have more operational flexibility to alter their production in response to changing conditions. Consequently, this type of resource is often ramped up as demand increases and ramped down when demand falls. In this way, coal resources are more likely to establish off-peak electricity prices than on-peak electricity prices. Conversely, natural-gas fired capacity is more likely to set electricity prices during peak demand periods. When green house gas emission costs are introduced, this basic trend can be altered.

Figure 3.3 shows illustrative dispatch costs for a coal plant and a natural-gas fired combined cycle plant at different carbon dioxide pricing points – no cost, $8/ton, $45/ton, and $100/ton. The coal plant is assumed to have a heat rate of 10,000 Btu/kWh and is faced with fuel prices of $2 per MMBtu. The gas-fired plant is assumed to have a heat rate of 7,200 Btu/kWh and is faced with a fuel price of $6 per MMBtu. Without any incremental carbon cost, Figure 3.3 shows a decided cost advantage for the coal asset. While the operating cost advantage for a coal plant is maintained when carbon costs are at $8/ton, the cost advantage begins to narrow. At $45/ton, both technologies are on nearly equal footing, with a slight advantage now in favor of the gas-fired combined cycle asset. Finally, at $100/ton, the cost advantage is reversed and is now decidedly in favor of the gas-fired plant.

Figure 3.3 – Green House Gas Cost Implications for Electric Generators



From the simplified example in Figure 3.3, one can appreciate how green house gas costs might affect wholesale electricity markets. With no carbon costs, the marginal unit is the gas-fired combined cycle, which, in this example, would support electricity prices somewhere north of $43 per MWh. When carbon costs climb to $100/ton, the marginal coal unit from this example would support wholesale electricity prices north of $120 per MWh. Of course, in reality, the power system is more complex than this simplified representation. There are additional resources—hydro power, nuclear, gas-fired peaking plants, and renewables—competing in the market. Moreover, there are other interactions that are likely to take place as greenhouse gas costs escalate and operational changes are implemented accordingly. For example, as carbon costs rise, it is possible that natural gas demand would increase, exerting upward pressure on gas prices. Similarly, even though natural fired capacity has a cost advantage relative to coal at higher carbon costs, coal does not have the operational flexibility to ramp output up and down with swings in demand. Regardless, given the range of potential policy outcomes, it is evident that the implications for greenhouse gas costs in the wholesale electricity market are highly variable and highly uncertain.

There are additional implications for the wholesale electricity market that extend beyond the direct cost impacts discussed above. For example, if carbon costs are exceptionally high and/or particularly volatile, the number of parties willing and or able to transact may begin to dwindle, and it is possible that depth and liquidity in the forward markets may suffer. Similarly, if a more Balkanized policy landscape materializes, there is a risk that transaction costs among market participants would increase. In yet another scenario, it is conceivable that poorly coordinated implementation rules among multiple programs might cause some market participants to retreat from specific trading hubs that are caught in a jurisdictional web of rules and ambiguity.

CURRENTLY REGULATED EMISSIONS

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

Ozone

Final action on the revisions to the National Ambient Air Quality Standards for ozone was completed on March 12, 2008. The EPA announced that the National Ambient Air Quality Standards for primary and secondary ground-level ozone would be significantly strengthened. The primary ozone standard, which is designed to protect public health and the secondary standard, which is designed to protect public welfare (including crops, vegetation, wildlife, buildings, national monuments, and visibility) from the negative effects of ozone, were both reduced to 0.075 parts per million.

The new standards took effect on May 27, 2008. States have until March 12, 2009, to make recommendations to the EPA as to whether an area should be designated attainment (meeting the standard), nonattainment (not meeting the standard) or unclassifiable (not enough information to make a decision). The EPA must promulgate its attainment/nonattainment designations by March 12, 2010, unless a one-year extension is granted because of insufficient information. By March 12, 2011, or one year after the EPA promulgates its designations, states will be required to submit their state implementation plans detailing how they will meet the new standards. A number of rules have been issued by the EPA that will potentially help states make progress toward meeting the revised ozone standards, including the Clean Air Interstate Rule to reduce ozone forming emissions from power plants in the eastern United States, and the Clean Diesel Program to reduce emissions from highway, non-road and stationary diesel engines nationwide.

Immediately following the promulgation of the strengthened ozone standards, multiple lawsuits were filed against the EPA. New York and thirteen other states sued the Environmental Protection Agency on May 27, 2008, demanding stricter air quality standards for ozone. New York was joined in the lawsuit by California, Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New Mexico, Oregon, the Pennsylvania Department of Environmental Protection, and Rhode Island. New York City and the District of Columbia also joined in the lawsuit. A coalition of environmental and public health advocates also filed a lawsuit against the Environmental Protection Agency on May 27, 2008, in a bid to strengthen the ozone standard. Meanwhile, Mississippi and a coalition of industry trade groups filed separate petitions for review May 23, 2008, and May 27, 2008, respectively, in the District of Columbia Circuit Court of Appeals, arguing the new standards are too strict.

After EPA tightened the 8-hour standard to 0.075 parts per million, several Utah counties located along the Wasatch Front were put in jeopardy of being designated non-attainment. Utah is now using certified monitored ozone data from 2005–2007 to determine specifically which areas need to be designated non-attainment of the 0.075 parts per million standard. The state must submit a recommendation to the EPA by March 2009. The EPA will then either accept or modify the state's recommendation, based on certified data from 2006-2008, and issue a final designation by March 2010. In Utah, ozone is principally a summer time problem when temperatures are high and daylight hours are long, but it may have implications to wintertime particulate problems as well. It is a mix of chemicals emitted mainly from vehicle tailpipes, diesel engines and industrial smokestacks. The Utah Department of Environmental Quality has indicated that its anticipated control strategy would focus on transportation, including tightening regulations for gasoline stations, and possibly consumer products, and certain industrial emissions.

Currently, with the exception of the Gadsby power plant, all of PacifiCorp Energy's operating fossil-fueled facilities are located in areas that are in attainment with the ozone National Ambient Air Quality Standards. The Gadsby plant is a gas fired facility located in downtown Salt Lake City, Salt Lake County, Utah. Salt Lake County is currently a non-attainment area for ozone. The Utah Department of Environmental Quality has stated that at this time, no coal- or natural gas-fueled power plants will be the subject of new control strategies.

Particulate Matter

On October 17, 2006, the EPA issued new National Ambient Air Quality Standards for particle pollution. The final standards addressed two categories of particle pollution: fine particles ($PM_{2.5}$), which are 2.5 micrometers in diameter and smaller; and inhalable coarse particles (PM_{10}), which are smaller than 10 micrometers. The Environmental Protection Agency strengthened the 24-hour fine particle standard from the 1997 level of 65 micrograms per cubic meter to 35 micrograms per cubic meter, and retained the current annual fine particle standard at 15 micrograms per cubic meter. The Agency also retained the existing national 24-hour PM_{10} standard of 150 micrograms per cubic meter and revoked the annual PM_{10} standard.

The new federal standards has put Utah's Wasatch Front – including all of Salt Lake and Davis Counties and portions of Weber, Box Elder and Toole counties – into a "non-attainment" status – as well as the low-lying portions of Utah and Cache Counties. Utah has until 2012 to draft a plan to EPA on how it will achieve compliance with the fine particulate NAAQS. According to the Utah Department of Environmental Quality, much of the particulate pollution is attributable to emissions from automobiles. Utah's monitoring suggests a seasonal problem characterized by episodic periods of very high concentrations of fine particulate that consists mostly of secondary particulate. The formation of these secondary particles is driven by winter-time temperature inversions which trap air in urbanized valleys. The mix of emissions associated with the urbanized areas reacts very quickly under these conditions to produce spikes in the concentration of fine particulate. Under these conditions, the observed concentrations are fairly uniform throughout the entire urbanized area. This underscores the association of urban areas with a mix of emissions that inherently reacts under these conditions to form PM2.5, and helps to define PM2.5 somewhat as an "urban" pollutant. All of this serves to highlight the distinction between urban and rural areas. Much of this phenomenon is also due to the fact that population is generally located within the lowland valley areas in which air is easily trapped by a temperature inversion. In other words, it is not enough to simply have an urban area with an urban mix of emissions; there must also be a barrier to dispersion under these conditions, which allows PM2.5 concentrations to build up over a period of several days and reach concentrations that exceed the NAAQS. This characterization of Utah's difficulties with fine particulate has shaped the State's approach to making the area designations.

Currently, with the exception of the Gadsby power plant, all of PacifiCorp's operating fossil-fueled facilities are located in areas that are in attainment with the fine particulate National Ambient Air Quality Standard. The Gadsby plant is a gas-fired facility located in downtown Salt Lake City, Salt Lake County, Utah. Salt Lake County has been proposed as a non-attainment area for fine particulate matter. The Utah Department of Environmental Quality has stated that at this time, no coal- or natural gas-fueled power plants will be the subject of new fine particulate matter control strategies.

Regional Haze

Within existing law, EPA's Regional Haze Rule and the related efforts of the Western Regional Air Partnership will require nitrogen oxide, sulfur dioxide, and particulate matter emissions reductions to improve visibility in scenic areas. Arizona, New Mexico, Oregon, Utah and Wyoming originally submitted state implementation plans addressing regional haze based upon 40 CFR 51.309, focusing on the reduction of sulfur dioxide emissions from large industrial sources located throughout the West. Regional Sulfur Dioxide Emissions and Milestone Reports, one of the requirements of the 309 state implementation plan, are submitted each year. The reports determine whether sulfur dioxide emitted by large industrial sources exceeds the sulfur dioxide emission milestones set in the states' Regional Haze state implementation plans. The sulfur dioxide milestones take into account emissions reductions either achieved or expected to be achieved from the installation of Best Available Retrofit Technology on eligible units.

The State of Wyoming submitted revisions to the 2003 309 Regional Haze state implementation plan to EPA Region 8 on November 24, 2008 and will now focus on impairment caused by sources of nitrogen oxides and particulate matter. Work on this phase of regional haze planning is underway with a draft SIP expected in the spring of 2009. Utah similarly adopted revisions to its regional haze state implementation plan on September 3, 2008, which became effective and enforceable in Utah on November 10, 2008. The package of materials was submitted to the EPA on September 18, 2008 and will become federally enforceable after EPA approves them.

Additionally, administrative rulemakings by EPA, including the Clean Air Interstate Rule will require significant reductions in emissions from electrical generating units that directly impact the national market for sulfur dioxide allowances. Compliance costs associated with anticipated future emissions reductions will largely depend on the levels of required reductions, the allowed compliance mechanisms, and the compliance time frame.

Mercury

In March 2005, the EPA released the final Clean Air Mercury Rule ("CAMR"), a two-phase program that would have utilized a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons. The CAMR required initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70 percent by 2018. The individual states in which PacifiCorp operates facilities regulated under the CAMR submitted state implementation plans reflecting their regulations relating to state mercury control programs. On February 8, 2008, a three-judge panel of the United States Court of Appeals for the District of Columbia Circuit held that the EPA improperly removed electricity generating units from Section 112 of the Clean Air Act and, thus, that the CAMR was improperly promulgated under Section 111 of the Clean Air Act. The court vacated the CAMR's new source performance standards and remanded the matter to the EPA for reconsideration. On March 24, 2008, the EPA filed for rehearing of the decision of the three-judge panel by the full court; rehearing was denied in May 2008. On September 17, 2008, the Utility Air Regulatory Group petitioned the United States Supreme Court for a writ of certiorari to review the United States Court of Appeals for the District of Columbia Circuit's February 8, 2008 decision overturning the rule. The EPA filed a petition to the United States Supreme Court on October 17, 2008 seeking to overturn the lower court's ruling.

While the Supreme Court considers whether to grant the petition for a writ of certiorari, all new coal fueled electric generating units and modifications of existing units will be required to obtain permits under Section 112 (g) of the Clean Air Act.[7] Under this provision, if no applicable emission limits have been established for a category of listed hazardous air pollutant sources, no person may construct a new major source or modify an existing major source in the category unless the EPA Administrator or the delegated state agency determines on a case by case basis that the unit will meet standards equivalent to the maximum achievable emission controls. Thus, new major sources or modifications to an existing major source would be required to perform a case by case analysis of the maximum achievable control technology and meet the emissions limitation that could be achieved in practice by the best performing sources in that category. If the Supreme Court decides to hear the appeal, any required maximum achievable control technology analysis requirement will likely be stayed for the duration of the rehearing. Until the court or the EPA take further action, it is not known the extent to which future mercury rules may impact PacifiCorp's current plans to reduce mercury emissions at their coal-fired facilities.

PacifiCorp is committed to responding to environmental concerns and investing in higher levels of protection for its coal-fired plants. PacifiCorp and MEHC anticipate spending $1.2 billion over a ten-year period to install necessary equipment under future emissions control scenarios to the extent that it's cost-effective.

CLIMATE CHANGE

Climate change has emerged as an issue that requires attention from the energy sector, including utilities. Because of its contribution to United States and global carbon dioxide emissions, the U.S. electricity industry is expected to play a critical role in reducing greenhouse gas emissions. In addition, the electricity industry is composed of large stationary sources of emissions that are thought to be often easier and more cost-effective to control than from numerous smaller sources. PacifiCorp and parent company MidAmerican Energy Holdings Company recognize these issues and have taken voluntary actions to reduce their respective CO_2 emission rates. PacifiCorp's efforts to achieve this goal include adding zero-emitting renewable resources to its

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[7] Refer to the memorandum from Robert Meyers, Deputy Assistant Administrator, Environmental Protection Agency, Office of Air and Radiation, dated January 7, 2009.

generation portfolio such as wind, geothermal, landfill gas, solar, combined heat and power (CHP), and hydro capacity upgrades, as well as investing in on-system and customer-based energy efficiency and conservation programs. PacifiCorp also continues to examine risk associated with future CO_2 emissions costs. The section below summarizes issues surrounding climate change policies.

Impacts and Sources

As far as sources of emissions are concerned, according to the U.S. Energy Information Administration, CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption. Among fossil fuel types, coal has the highest carbon content, natural gas the lowest, and petroleum in-between. In the Administration's *Annual Energy Outlook 2009 Early Release* reference case, energy-related CO_2 emissions reflect the quantities of fossil fuels consumed and, because of their varying carbon content, the mix of coal, petroleum, and natural gas. Given the high carbon content of coal and its use currently to generate more than one-half of U.S. electricity, prospects for CO_2 emissions depend in part on growth in electricity demand. Electricity sales growth in the *AEO2009* reference case slows as a result of a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, housing patterns, and economic activity. With slower electricity growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related CO_2 emissions grow by just 0.5 percent per year from 2007 to 2030. CO_2 emissions from transportation activity also slow in comparison with the recent past, as Federal CAFE standards increase the efficiency of the vehicle fleet, and higher fuel prices moderate the growth in travel.

Taken together, all these factors tend to slow the growth of the absolute level of primary energy consumption and promote a lower carbon fuel mix. As a result, energy-related emissions of CO_2 grow by 7 percent from 2007 to 2030—lower than the 11-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive as CO_2 emissions grow by about one-tenth of the increase in GDP, and emissions per capita decline by 14 percent.

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

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

International and Federal Policies

Numerous policy activities have taken place and continue to develop. At the global level, most of the world's leading greenhouse gas (GHG) emitters, including the European Union (EU), Japan, China, and Canada, have ratified the Kyoto Protocol. The Protocol sets an absolute cap on GHG emissions from industrialized nations from 2008 to 2012 at seven percent below 1990 levels. The Protocol calls for both on-system and off-system emissions reductions. While the U.S. has thus far rejected the Kyoto Protocol, numerous proposals to reduce greenhouse gas emissions have been offered at the federal level. The proposals differ in their stringency and choice of policy tools.

In June 2008, the Lieberman-Warner Bill—the Climate Security Act (CSA)—failed in the Senate. The CSA set a goal for reducing greenhouse gas emissions of more than 60 percent by 2050.[8] Furthermore, the CSA sought to institute a domestic offset program that would allow facilities to meet up to 15 percent of their compliance with allowances generated by offset projects, or by purchasing or borrowing credits. The CSA also included a "Bonus Allowance Account" whereby companies would be awarded for sequestering their carbon emissions.[9] Perceived effects on the national economy derailed the CSA's passage. The EPA estimated the CSA would decrease the nation's gross domestic product between \$238 billion and \$983 billion by 2030, while increasing electricity prices 44 percent by 2030.[10] Further, due to rising electricity costs the average household's consumption would decrease an average of \$1,375 by 2030.[11]

In addition to the CSA, On October 7, 2008, the former Chairman of the Committee on Energy and Commerce, John D. Dingell, released draft climate change legislation calling for the lowering of emissions to 80 percent of 2005 levels by 2050. The draft legislation proposes to balance its costs through high quality offsets, special reserve emission allowances, and carbon capture and sequestration.[12]

Recent Democratic victories in the House, Senate and the Presidency appear likely to boost efforts to strengthen U.S. global warming policy. Congress and federal policy makers are considering climate change legislation and a variety of national climate change policies and President Obama has expressed support for an economy-wide greenhouse gas cap and trade program that would reduce emissions 80 percent below 1990 levels by 2050. As a result of these policies, PacifiCorp's electric generating facilities are likely to be subject to regulation of greenhouse gas emissions within the next several years.

U.S. Environmental Protection Agency's Advance Notice of Public Rulemaking

On July 11, 2008, the Environmental Protection Agency released an Advance Notice of Proposed Rulemaking inviting public comment on the benefits and ramifications of regulating greenhouse gases under the Clean Air Act. This Advance Notice of Proposed Rulemaking is one

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[8] Erin Kelly, "Senate Poised to Take Up Sweeping Global Warming Bill," USA Today, http://www.usatoday.com/news/washington/environment/2008-05-17-global-warming_N.htm, May 17, 2008.

[9] *Id.*

[10] U.S. EPA, EPA Analysis of the Lieberman-Warner Climate Security Act of 2008, available at: http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf.

[11] "U.S. Environmental Protection Agency Estimates Cost of Lieberman-Warner Bill to Limit Greenhouse Gas Emissions," National Rural Electric Cooperative Association, available at: http://www.nreca.org/main/NRECA/PublicPolicy/issuespotlight/20080319ClimateChange.htm, March 19, 2008.

[12] John D. Dingell, Climate Change Discussion Draft Legislation, U.S House of Representatives, Committee on Energy and Commerce, October 7, 2008; For a complete list of the cap-and-trade legislation introduced in Congress in 2008, see http://www.pewclimate.org/docUploads/Chart-and-Graph-120108.pdf.

of the steps the Environmental Protection Agency has taken in response to the United States Supreme Court's decision in *Massachusetts v. Environmental Protection Agency*.[13] A decision to regulate greenhouse gas emissions under one section of the Clean Air Act could or would lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants.

The Advance Notice of Proposed Rulemaking reflects the complexity and magnitude of the question of whether and how greenhouse gases could be effectively controlled under the Clean Air Act. Many of the key issues for discussion and comment in the Advance Notice of Proposed Rulemaking included:

- Descriptions of key provisions and programs in the Clean Air Act, and advantages and disadvantages of regulating greenhouse gas emissions under those provisions.
- How a decision to regulate greenhouse gas emissions under one section of the Clean Air Act could or would lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants.
- Issues relevant for Congress to consider for possible future climate legislation and the potential for overlap between future legislation and regulation under the existing Clean Air Act.
- Scientific information relevant to, and the issues raised by, an endangerment analysis.
- Information regarding potential regulatory approaches and technologies for reducing greenhouse gas emissions.

The Environmental Protection Agency accepted public comment on the Advance Notice of Proposed Rulemaking until November 28, 2008. PacifiCorp's parent, MidAmerican Energy Holdings Company submitted comments on the Advance Notice of Proposed Rulemaking. In these comments, MidAmerican stressed the Company's position that Clean Air Act regulations are an inferior strategy for reducing greenhouse gas emissions compared to a comprehensive legislative program that Congress is expected to enact. Promulgating greenhouse gas regulations under the Clean Air Act would be, at best, unnecessary because Congress is expected to enact a program that is economy-wide, market-based, incents technology, and encourages other countries to take action. MidAmerican further highlighted that any mandatory domestic program to reduce greenhouse gas emissions should be implemented consistent with the following principles:

- Technology development and deployment is essential to achieving a 60 to 80 percent reduction in greenhouse gas emissions. A significant national commitment to funding and advancing low-carbon technologies is critical.

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[13] In April 2007, the Supreme Court concluded in that case that greenhouse gas emissions meet the Clean Air Act definition of "air pollutant," and that section 202(a)(1) of the Clean Air Act therefore authorizes regulation of greenhouse gas emissions subject to an Agency determination that greenhouse gas emissions from new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare (Endangerment Finding).

- Immediate opportunities for emissions reduction and avoidance should be pursued through investments in energy efficiency, renewable energy and increasing the efficiency of existing generation.
- Any program to regulate greenhouse gas emissions should seek to avoid short-term responses that do not provide a long-term path to a low carbon future.
- Programs implemented to reduce greenhouse gas emissions should achieve their intended purpose—reducing or avoiding emissions—and not simply serve as a source of revenue or offsetting taxes.

In April 2009, the EPA found that concentrations of CO_2 and five other greenhouse gases pose dangers to human health and welfare, and is in the process of holding public hearings on further action to regulate these greenhouse gases under the Clean Air Act.

Regional State Initiatives

Activities undertaken by regional state climate change initiatives continued to be significant in 2008 and will continue into 2009. The most notable developments are as follows:

Midwestern Regional Greenhouse Gas Accord

On November 3, 2008, the ten Midwestern Regional Greenhouse Gas Accord Partners released Draft Recommendations, suggesting a target of between 15-25 percent below 2005 levels by 2020 and a target of between 60-80 percent below 2005 levels by 2050. They also recommended that the program cover a comprehensive slate of activities including electricity generation and imports, industrial combustion sources, credible and measurable industrial process sources, transportation fuels, and fuels serving residential, commercial, and industrial buildings. The Advisory Group hopes to include 85-95 percent of emissions for each sector, and suggests linking the Midwestern Greenhouse Gas Accord cap-and-trade program to the Regional Greenhouse Gas Initiative, Western Climate Initiative, and other mandatory greenhouse gas emissions reduction programs.

Regional Greenhouse Gas Initiative

In 2008, the ten Regional Greenhouse Gas Initiative Partners held successful pre-compliance auctions in September and December. The first auction sold 12,565,387 carbon dioxide allowances at a clearing price of $3.07 per allowance, raising more than $38.5 million. The second auction sold 31,505,898 allowances at a clearing price of $3.38 per allowance, raising more than $106 million. Under the Regional Greenhouse Gas Initiative, this combined $140 million will be used on a wide variety of approved efforts to limit and sequester carbon, as well as adapt to the impacts of climate change.

Western Climate Initiative

In September 2008, the Western Climate Initiative Partners released their proposal for a regional cap-and-trade program beginning in 2012. The seven states and four provinces would cover 20 percent of the United States, and 70 percent of the Canadian, economies respectively. Covered emitters include electricity generators and industrial and commercial stationary sources that emit more than 25,000 metric tons of carbon dioxide equivalent per year. Beginning in 2015, the market would expand to also cover petroleum-based fuel combustion from residential, commercial, and industrial operations, for an overall goal of reducing emissions to 15 percent below 2005 levels by 2020.

Individual State Initiatives

State Economy-wide Greenhouse Gas Emission Reduction Goals

An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to, (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. Oregon's goals seek to (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2008, Colorado announced Executive Order D-004-08, setting a goal of reducing greenhouse gas emissions to 20 percent below 2005 levels by 2020, and 80 percent below 2005 levels by 2050. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

State Greenhouse Gas Emission Performance Standards

In addition, California and Washington have adopted legislation that impose greenhouse gas emission performance standards to all electricity generated within the state or delivered from outside the state to serve retail load. The greenhouse gas emissions performance standard is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility, effectively prohibiting the use of new pulverized coal generation to serve retail load. The state of Idaho had adopted a de-facto prohibition on new pulverized coal generation located within the state when it decided not to participate in the federal Clean Air Mercury Rule's cap-and-trade program, and as a result received a zero state budget for mercury emissions.

Other Recent State Accomplishments

In October 2008, the California Public Utilities Commission and the California Energy Commission completed a collaborative proceeding to develop and provide recommendations to the California Air Resources Board on measures and strategies for reducing greenhouse gas emissions in the electricity and natural gas sectors. The October 16, 2008 final decision[14] is the second policy decision to be issued pursuant to this effort. In an earlier decision, Decision 08-03-018 issued in March 2008, the Commissions provided their initial greenhouse gas policy recommendations to the Air Resources Board. In December, the Air Resources Board adopted the "Assembly Bill 32 Scoping Plan to Reduce Greenhouse Gas Emissions in California." The strategy relies on 31 new rules, including a cap-and-trade program, set to begin in 2012, impacting power plants, refineries, and large factories. Assembly Bill 32 (2006) requires California to cut greenhouse emissions

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[14] Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, available at: http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/92288.pdf .

to 1990 levels by 2020. The Air Resources Board is also implementing mandatory greenhouse gas reporting with a regulation that was approved by the Board in December 2007, and became effective on December 2, 2008.[15]

In October 2008, the Oregon Environmental Quality Commission approved new mandatory greenhouse gas reporting rules. The reporting rules are aimed at developing a statewide strategy for reducing emissions to 10 percent below 1990 levels by 2020, and to 75 percent below 1990 levels by 2050. Additionally, the Legislature passed Oregon House Bill 3619 expanding the business energy tax credit program with additional incentives for manufacturers of renewable energy equipment located in Oregon. Senate Bill 80, which implements a state CO_2 cap-and-trade system and emission reporting rules, is under consideration.

In 2008, the Utah Legislature passed Senate Bill 202 establishing a renewable energy target of 20 percent by 2025, with zero-carbon emitting electricity facilities exempt from the target. The bill also establishes a process for establishing a carbon capture and storage regulatory framework. The Utah Carbon Capture and Geologic Sequestration Workgroup was subsequently formed.

In June 2008, the Washington Department of Ecology adopted its final rules implementing a greenhouse gas emissions performance standard of 1,100 pounds of greenhouse gas per megawatt (MW) for all new electrical generation built within Washington, or used to serve the Washington retail load. The Department also adopted guidelines for carbon capture and sequestration projects. House Bill 2815 directs the Department of Ecology to develop, in coordination with the Western Climate Initiative, a design for a cap and trade system to meet the state's greenhouse gas emissions reductions limits of 50 percent below 1990 levels by 2050. In December 2008, the Department delivered to the legislature specific recommendations for approval, and requested authority to implement the preferred design of the greenhouse gas reduction system in order to have the system in effect by January 1, 2012.[16] Second, House Bill 2815 requires operations emitting at least 10,000 metric tons, or on-road motor vehicle fleets that emit 2,500 tons of greenhouse gases, to report their emissions to the Washington Department of Ecology beginning in 2010 for 2009 emissions. House Bill 2687 addresses the Department of Ecology's authority and direction for participation in the Western Climate Initiative, and directs the state to ensure that a design for a cap-and-trade system confers equitable economic benefits and opportunities to electric utilities. Further, the language directs the state to advocate for a regional system that addresses competitive disadvantages that could be experienced because of implementing strict greenhouse gas reduction programs. Senate Bill 6580 requires the Department of Community, Trade, and Economic Development to develop and provide advisory climate change responses to counties and cities, establish a local government global warming mitigation and adaptation program to address climate change through land use and transportation planning, and present a report to the legislature regarding policies to address and assess the impacts of climate change.

Wyoming House Bill 89, Pore Space Ownership, and House Bill 90, Carbon Capture and Sequestration, were signed into law on March 4, 2008. House Bill 89 is intended to affirm the

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[15] Mandatory Greenhouse Gas Emissions Reporting, available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

[16] Growing Washington's Economy in a Carbon-Constrained World: A Comprehensive Plan to Address the Challenges and Opportunities of Climate Change, available at: http://www.ecy.wa.gov/pubs/0801025.pdf.

"American or Majority Rule" that the ownership of "pore space" in underground strata below the surface lands and waters of the state of Wyoming is vested in the several owners of the surface, but can be severed from the surface rights and sold separately. "Pore space" is defined to mean subsurface space that can be used as storage space for CO_2 or other substances. Wyoming House Bill 90 establishes a permit program for carbon storage and sequestration underground injection wells. The law establishes a permit program for injection of CO_2 and associated constituents for sequestration to be issued by Wyoming Department of Environmental Quality. The law specifically states that injection of CO_2 for enhanced recovery of oil or gas approved by Wyoming Oil and Gas Conservation Commission is not subject to the new permit program. The Wyoming Carbon Sequestration Working Group was subsequently formed.[17]

Corporate Greenhouse Gas Mitigation Strategy

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

- **Policy** – PacifiCorp has supported legislation that enables GHG reductions while addressing core customer requirements. PacifiCorp will continue to work with regulators, legislators, and other stakeholders to identify viable tools for GHG emissions reductions.
- **Planning** – PacifiCorp has incorporated a reasonable range of values for the cost of CO_2 in the 2008 IRP in concert with numerous alternative future scenarios to reflect the risk of future regulations that can affect relative resource costs. The Company is engaged in augmenting its regulatory analysis capabilities, including enhancing its IRP models to capture a more detailed representation of climate change rules. It is involved with such organizations as the Electric Power Research Institute for continued study of regulatory impacts on utilities and customers. Additional voluntary actions to mitigate greenhouse gas emissions could increase customer rates and represent key public policy decisions that the Company will not undertake without prior consultation with regulators and lawmakers at state and federal levels.
- **Procurement** – PacifiCorp recognizes the potential for future CO_2 costs in requests for proposal (RFPs), consistent with its treatment in the IRP. Commercially available carbon-capturing and storage technologies at a utility scale do not exist today. Carbon-capturing technologies are under development for both pulverized coal plant designs and for coal gasification plant designs, but require research to increase their scale for electric utility use.
- **Accounting** – PacifiCorp has adopted transparent accounting of GHG emissions by joining the California Climate Action Registry. The Registry applies rigorous accounting standards, based in part on those created by the World Business Council on Sustainable Development and the World Resources Institute, to the electric sector.

The current strategy is focused on meaningful results, including installed renewables capacity and effective demand-side management programs that directly benefit customers. While these efforts provide multiple benefits of which lower GHG emissions are a part, they are clearly attractive within an effective climate strategy and will continue to play a key role in future procurement efforts.

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[17] http://deq.state.wy.us/carbonsequestration.htm

EPRI ANALYSIS OF CO_2 PRICES AND THEIR POTENTIAL IMPACT ON THE WESTERN U.S. POWER MARKET

In 2008, the Electric Power Research Institute (EPRI) organized and conducted a broad-brush study to identify and analyze the likely effects of climate change policy for western U.S. (WECC region) generators and customers. A diverse collection of nine western generation companies, including PacifiCorp, funded and participated extensively in this effort.

The WECC region has certain unique power system characteristics, which make it an interesting laboratory to study the effects of climate policy. These include a large existing base of hydro generation supporting the regional market, as well as a growing collection of state-level Renewable Portfolio Standard targets. These existing and anticipated generation resources together form an important baseline serving this region if their potential can be realized. On the other hand there are significant uncertainties surrounding this realization, including the sustainability of hydro generation into the future, and the feasibility of infrastructure investments (i.e. transmission capacity, backup generation) needed to realize such an extensive renewables build out.

The study results attempt to reflect and recognize uncertainties in future power markets, through an examination of several alternative future scenarios. A Reference Case, reflecting a largely stable and optimistic future, was described for baseline purposes. In addition, a case called "Wild Card", reflecting a more pessimistic view of future events, was presented as an alternative. The study was designed to examine macro-level effects of alternative CO_2 price levels on power system dispatch, new generation investment decisions, emissions levels and power prices. The analysis included: representation of a full electric system supply-demand balance; capacity expansion and retirement methodology driven by the relative economics of both existing and new resources, and; a demand response representation, allowing future load growth to respond to future price changes.

Key conditioning assumptions of the Reference Case include: future load growth in this market was assumed equal to the recent historical period 1995-2005, at 1.73 percent per year; natural gas prices (real 2006 dollars) were set to a recent (May 6, 2008) NYMEX forward curve projection through the year 2020, then held constant at 2020 levels; capital costs for new generating plant were driven by EPRI internal estimates from 2007, and further inflated 25 percent in recognition of continual and inexorable escalation (at least until very recently) in all global construction markets, and; western state RPS targets were assumed to be met in future years, per individual state law.

The behavior of the power system and electric customers was investigated over a future period 2006 through 2030, for a series of CO_2 price points (starting at \$0/ton and escalating up to \$100/ton) imposed beginning in 2012. The analysis assumed that the CO_2 price would remain constant (in real 2006 \$) from 2012 through 2030. This flat scenario CO_2 price structure was designed to show how the electric sector would equilibrate to specific prices levels over time.

The results of this analysis show, in the first instance, that a higher CO_2 price will drive up the power price and drive down emissions. The power price in the initial year (2012) increases almost linearly with the CO_2 price, because the power system has very limited response capability in the very short term. There is some capability to switch resource usage from coal to natural gas, but it is actually quite limited in WECC, so the only real option is to pass price increases on to consumers. Similarly, the short-term ability to reduce emissions is virtually nil except at very high CO_2 prices where the level of demand itself is reduced through price effects.

This inflexibility is much less true as time marches on. In later years the response is both more pronounced for emissions and more limited for power prices, as the generating stock begins to turn over and new investments are made in non-emitting generation. Note in particular that emissions reductions by 2030 accelerate significantly once the \$50-\$60 CO_2 price range is reached, when nuclear generation starts to penetrate the market. It is only when wholesale power prices reach roughly the \$100 range that the nuclear technology can expect to cover its investment and carrying costs. The response of power price to CO_2 price is also more moderated in later years, as low-busbar cost, non-emitting technologies enter the mix and temper power prices.

The generation mix details of these phenomena are equally illuminating. In the absence of a CO_2 policy the existing mix of generation is not appreciably affected. As time marches into the future, demand growth is largely met with new renewable generation and new natural gas-fired generation. A small amount of customer response to rising prices tempers demand growth just a bit. Emissions keep growing.

A \$50/ton CO_2 price brings about noticeable future changes. In the first instance, it is interesting to note that this represents the "stabilization" price, or the price that essentially flattens emissions growth into the future. As power prices are also driven up in this case, customer response is also greater and demand growth is tempered even further. Higher power prices also begin to affect the generation mix, pushing out existing coal over time and eliciting more gas generation as replacement energy. Notably, at a \$50 CO_2 price there is still little change in the overall generation mix over time, as the power price is not yet quite high enough to usher in significant capacity in non-emitting technologies.

At CO_2 prices of \$85 and higher, the generation mix begins to change noticeably due to the new technology opportunities presented by higher power prices. Note first that in this case emissions shrink significantly over time, in reaction to both increased customer price response and to changes in generation technology. Existing coal generation shrinks virtually to nothing by 2030, and is replaced in part with non-emitting nuclear generation – assumed to be available in the 2020 timeframe – as well as renewables. On the other hand, power prices actually moderate over time at the \$85 CO_2 level, due in large part to the switch out of coal generation (and its \$85/ton surcharge) and into very low busbar-cost alternatives such as nuclear and renewables.

An alternative, more pessimistic case was investigated as well. The "Wild Card" case represents an alternative future – one in which both events and policy responses to them work against future greenhouse gas control. Key differences in assumptions for the "Wild Card" case include: an assumed higher load growth rate; assumed higher natural gas prices; higher capital costs (25 percent premium); an assumed lower customer demand response, and; assumed nuclear power unavailability for the duration of the study.

The "Wild Card" future requires a higher CO_2 price than the Reference Case to stabilize emissions over time (closer to the \$70-\$80 range). Due to higher capital costs overall, as well as the nuclear penetration constraint, capital stock turnover is much more sluggish in the pre-2030 time frame, and emissions are still growing at the \$50 CO_2 price level. Existing generation – coal and gas – is necessarily used more heavily, and emissions stubbornly resist reduction.

Even at a \$100 CO_2 price, emissions reductions in the "Wild Card" case are still minimal. In fact it takes a CO_2 price in the range of \$125-\$150 to effect significant reduction, under a "Wild Card" future.

Power prices are impacted as well. The "Wild Card" future leads to a persistent \$20 premium in wholesale power prices, regardless of the size of the CO_2 price assumed.

The foregoing analysis of western power markets was an attempt to postulate several alternative futures, and examine the implications of each on suppliers and consumers. The analysis is aggregate – high-level and suggestive – and certainly glosses over many details and intricacies in an attempt to focus squarely on the larger picture. Many "devils in the details" have been undoubtedly simplified, including the following.

All details of power system operations are treated abstractly, at best. This abstraction is clearest in the representation of renewable generation and its growth potential. Realistically, there will need to be significant infrastructure (i.e. transmission capacity, backup combustion turbine generation or energy storage to mitigate intermittency) built in the west, additional to renewable generation capacity, to support its usage. This additional infrastructure has been represented in the analysis as a simple capital adder to the renewables cost estimate. Whether this additional investment will be financially - or politically - feasible is certainly an open question. It may be that the renewables contribution has been overestimated. On the other hand, the base renewables projections (the vast bulk of the renewables capacity in any scenario) used in this analysis are merely what has been mandated by numerous western states as their avowed targets, and these targets are already today well within reach in many states.

Natural gas prices are also an important driver of the analysis, and they have been notoriously volatile for the last 30 years. Among knowledgeable professionals there are resource depletion arguments that indicate prices will go up, and liquefied natural gas emergence arguments that indicate prices will go down. Still and all, the NYMEX forward curve remains the best consensus estimate of what will happen to gas prices in the future; this has formed the basis of the estimates in this analysis.

Customer response to price changes is universally recognized as a real phenomenon, and just as universally acknowledged as impossible to accurately measure. In this analysis the long-term elasticity parameter finally chosen (-0.50) is based on EPRI studies from early in the decade, but it could well be overstated.

The above caveats notwithstanding, there are several important conclusions that can be drawn from the analysis. These include the following.

It is certainly possible to wring emissions growth out of the power sector in western states, given high enough CO_2 price signals and sufficient time. In the Reference Case future, a price of about

$50 will flatten emissions growth, and a price of about $80 will substantially reduce it. In the "Wild Card" future, it will require about an $80 price to flatten growth and a price in excess of $125 to make substantial reductions.

CO_2 prices in these ranges are unprecedented, and will lead to unprecedented retail power prices as well, in the range of 40-80 percent higher (depending on CO_2 price level)—in the immediate aftermath of price imposition—than they are in WECC today. Such levels will cause anxiety for the electricity sector and its customers as well. However, over time (18 years is the horizon of this analysis, actually, higher prices will create investment incentives for the addition of non-emitting generation, and more such capacity will enter the market if it functions reasonably well. This will tend to temper power price differentials over time. In the analysis retail prices in 2030 are projected to end up more like 15-30 percent higher than the $0 case, a far cry from the differentials in 2012.

Customer response to price increases will tend to hold power price levels down in its turn as well. Without this effect prices might be expected to rise even higher. This is a mixed blessing at best, as it will represent a real loss in consumer welfare, albeit not measured explicitly in the analysis.

Natural gas price and availability are critical linchpins in the Western power system in early years, as short-term reductions in emissions will depend on the ability of natural gas generation to fill the gaps left by coal cutbacks. This criticality will fade over time, as new non-emitting technologies increasingly will enter the market and fill the void.

For the western power industry, the EPRI analysis helps inform possible decisions by highlighting two important CO_2 price signals necessary to effectuate changes within the electricity sector. The first is the CO_2 price that is just high enough to encourage a utility interested in building new electricity generation to choose a lower-emitting—albeit more expensive—technology over a cheaper, but higher-emitting technology. A second CO_2 price is one that is sustained at a high enough level as to make existing fossil-fueled power plants uneconomic to continue operating. Under either situation, higher costs will inevitably be passed on to consumers in the form of higher electricity rates, but if accompanied by sufficient time to adapt to the new regulatory regime, costs can be mitigated.

ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

In late December 2007, Congress passed the Energy Independence and Security Act (P.L. 110-140, which has three major provisions covering corporate average fuel economy standards, the renewable fuels standard, and appliance/lighting efficiency standards.

For corporate average fuel economy, the law sets a target of 35 miles per gallon for the combined fleet of cars and light trucks by model year 2020. Also, a fuel economy program is established for medium- and heavy-duty trucks, and a separate fuel economy standard is created for work trucks. These were the first new corporate average fuel economy standards in 32 years, and the increases represent a roughly 40 percent increase over today's requirements.

For the renewable fuels standard, the law sets a modified standard that starts at 9.0 billion gallons of renewable fuel in 2008 and rises to 36 billion gallons by 2022. Of the latter total, 21 billion gallons is required to be obtained from cellulosic ethanol and other advanced biofuels. This represents a six-fold increase over the mandate that is in place.

In the area of energy efficiency (specifically appliance and lighting efficiency standards), the law set energy efficiency standards for broad categories of incandescent lamps (light bulbs), incandescent reflector lamps, and fluorescent lamps. A required target is set for lighting efficiency, and energy efficiency labeling is required for consumer electronic products. The law will effectively phase out most common types of incandescent light bulbs over the next four to six years by increasing the energy efficiency standards of light bulbs by 30 percent. The new standard is technology-neutral, allowing consumers a choice among several efficient lighting technologies, including improved halogen-incandescent bulbs, compact fluorescent lamps and eventually light-emitting diodes and other advanced lighting technologies. The impact of the lighting efficiency standards has been accounted for in PacifiCorp's load forecasting and IRP portfolio modeling (See Chapter 5, Resource Needs Assessment). Efficiency standards are set by law for external power supplies, residential clothes washers, dishwashers, dehumidifiers, refrigerators, refrigerator/freezers, freezers, electric motors, residential boilers, commercial walk-in coolers, and commercial walk-in freezers. Further, the U.S. Department of Energy is directed to set standards by rulemaking for furnace fans and battery chargers.

The Act also requires a 30 percent reduction in energy consumption by 2015 in federal buildings. (The General Services Administration owns and leases over 340 million square feet of space in more than 8,900 buildings, located in every state.)

The Act also encourages the development of carbon capture technology by (1) expanding and improving the Department of Energy's existing carbon sequestration research, (2) requiring a national assessment of capacity to sequester carbon, (3) requiring the Secretary of Energy to conduct seven large-scale geologic sequestration tests, with at least one as an international partnership, an d(4) increasing the funding authorization for all projects included in the new carbon capture and storage research, development and demonstration program, with an emphasis on large-scale geologic carbon dioxide injection demonstration projects.

Another title of the Act is the Advanced Geothermal Energy Research and Development Act of 2007. It calls for research, development, demonstration, and commercial application in five major areas: (1) geopressured resource production, which is co-produced in oil and gas fields; (2) cost-sharing drilling; (3) enhanced geothermal systems; (4) creation of a national exploration and development geothermal technology transfer and information center; and (5) international geothermal collaboration.

RENEWABLE PORTFOLIO STANDARDS

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

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

RPS policies are currently implemented at the state level (although interest in a federal RPS is expanding), and vary considerably in their requirements with respect to time frame, resource eligibility, treatment of existing plants, arrangements for enforcement and penalties, and whether they allow trading of renewable energy credits. By 2008, twenty-five states adopted mandatory renewable portfolio standards, five states adopted voluntary renewable portfolio standard, and fourteen states had adopted no form of renewable portfolio standard.

Within PacifiCorp's service territory, California, Oregon, and Washington have mandatory renewable portfolio standards, with Utah having adopted a voluntary renewable portfolio standard. Each state is summarized in Table 3.1 and additional discussion below.

Table 3.1 – Summary of state renewable goals (as applicable to PacifiCorp)

State	Goal
California	Obtain 20 percent of electricity from renewable resources by 2010.
Oregon	Obtain 25 percent of electricity from renewable resources by 2025 in the following increments: • 5 percent: 2011 – 2014 • 15 percent: 2015 – 2019 • 20 percent : 2020 – 2024 • 25 percent: 2025 and beyond
Utah	By 2025, obtain 20 percent of annual adjusted retail sales from cost effective renewable resources, as determined by the Public Service Commission or renewable energy certificates.
Washington	Obtain 15 percent of electricity from renewable resources by 2020 in the following increments: • 3 percent by January 1, 2012 through December 31, 2015 • 9 percent by January 1, 2016 through December 31, 2019 • 15 percent by January 1, 2020 and each year thereafter

California

California law requires electric utilities to increase their procurement of renewable resources by at least one percent of their annual retail electricity sales per year so that 20 percent of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities received further guidance from the California Public Utilities Commission on the treatment of small multi-jurisdictional utilities in the California Renewable Portfolio Standard program within decision, D.08-05-029. In August 2008, concurrent with its annual renewable portfolio standard compliance filing, PacifiCorp, joined by Sierra Pacific Power Company, filed a Joint Motion for Review of the decision. As discussed in D.08-05-029, since the inception of the Renewable Portfolio Standard program, PacifiCorp and other small multi-jurisdictional utilities operated in a state of regulatory uncertainty regarding the nature of their Renewable Portfolio Standard program compliance obligations. PacifiCorp's filing represented its interpretation of D.08-05-029, including banking of renewable portfolio standard procurement made while it awaited further guidance from the California Public Utilities Commission on the treatment of small multi-jurisdictional utilities during the 2004-2006 period. PacifiCorp believes its interpretation is consistent with D.08-05-029 and best serves the interests of its customers by recognizing past, good faith efforts to comply with California's Renewable Portfolio Standard program beginning January 1, 2004. PacifiCorp is currently awaiting the California Public Utilities Commission's response to the Joint Motion for Review.

Oregon

In June 2007, the Oregon Renewable Energy Act was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council area, and unbundled renewable energy credits can be used. The Oregon Public Utilities Commission and the Oregon Department of Energy have undertaken additional rulemaking proceedings to further implement the initiative.

Utah

In March 2008, Utah's governor signed Utah Senate Bill 202, "Energy Resource and Carbon Emission Reduction Initiative;" legislation supported by PacifiCorp. Among other things, this provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used.

Washington

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are three percent of retail sales by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020. Qualifying renewable energy sources must be located within the Pacific Northwest. The Washington Utilities and Transportation Commission adopted final rules to implement the initiative.

Federal Renewable Portfolio Standard

Congress has taken up federal energy policy legislation, including the possibility of a federal RPS. President Obama has pledged to "spark the creation of a clean energy economy" as part of his plan aimed at reinvigorating the U.S. economy, in part by doubling production of "alternative energy" in the next three years—aided by subsidies for "low emissions coal plants," biofuels and renewable energies—and by pursuing a federal renewable portfolio standard mandating that 25 percent of U.S. electricity come from renewable sources by 2025. Passage of a federal renewable portfolio standard would break a major standoff in Congress as both the House and Senate have passed various forms of a renewable portfolio standard in recent years but failed to concur on the details. The Waxman-Markey Bill represents the latest effort, and specifies a renewable electric compliance requirement of 20 percent by 2020.

Proponents of a national renewable portfolio standard argue it would ease the move toward a mandatory cap on greenhouse gas emissions by requiring utilities to invest in low-carbon energy sources. Enactment of a federal renewable portfolio standard would be a significant shift in the way electric utilities are regulated, dramatically increasing the authority of the federal government to dictate the makeup of a utility's energy portfolio—a power currently exercised by state governments.

Renewable Energy Certificates

Absent either a RPS compliance obligation or an opportunity to bank unbundled renewable energy certificate (RECs) for future year RPS compliance, PacifiCorp has historically relied on an assumption that a renewable project may generate $5 per megawatt-hour for five years from the sale of unbundled RECs. Unbundled REC sales have helped mitigate the near-term cost differential between new renewable resources and traditional generating resources.

However, once greenhouse gas emissions are regulated, surplus unbundled REC sales would cease. PacifiCorp assumes if an unbundled REC is sold, then the underlying power (aka "null" power) would likely have a carbon emissions rate imputed upon it by regulatory authorities, thus obligating PacifiCorp to purchase either allowances or carbon offsets sufficient to cover the imputed carbon emissions. By selling an unbundled REC, PacifiCorp may generate revenue, but risks incurring a new carbon liability. Once greenhouse gases are regulated—and until the unbundled REC and carbon markets are reconciled—PacifiCorp plans to cease selling unbundled RECs.

HYDROELECTRIC RELICENSING

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

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of two hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary Orders from the Federal Energy Regulatory Commission (FERC). The Klamath River hydroelectric project continues to work with parties to reach a settlement agreement on future project conditions, and the Condit project is seeking a Surrender Order to decommission the project.

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

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

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and generally takes nearly ten or more years to complete, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2008, PacifiCorp had incurred $56.6 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As relicensing and/or decommissioning efforts continue for the Klamath River and Condit hydroelectric projects, additional process costs are being incurred that will need to be recovered from customers. Also, new requirements contained in

FERC licenses or decommissioning Orders could amount to over $1.2 billion over the next 30 to 50 years. Such costs include capital and operations and maintenance investments made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect fish resulting in lost generation. Over 95 percent of these relicensing costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

Treatment in the IRP

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

PacifiCorp's Approach to Hydroelectric Relicensing

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

RECENT RESOURCE PROCUREMENT ACTIVITIES

2012 Request for Proposals for Base Load Resources

PacifiCorp issued this RFP on April 5, 2007, to procure up to 1,700 MW of base-load resources for 2012-2014. In December 2008, PacifiCorp submitted an application for "Approval of Significant Energy Resource Decision and for Certificate of Public Convenience and Necessity" to the Public Service Commission of Utah for the Lake Side II combine-cycle plant. As discussed above, in February 2008, the Company terminated the construction contract for this plant.

2008 All-Source Request for Proposals

The 2008 All-Source RFP, which was issued on October 2, 2008, sought up to 2,000 MW of system-wide base-load capacity, intermediate load capacity, third-quarter market purchases, load curtailment, PURPA Qualifying Facilities, and dispatchable/schedulable renewables, with online dates between 2012 through 2016.[18] Both the Public Utility Commission of Oregon and the Public Service Commission of Utah approved the RFP.

In late February 2009, PacifiCorp suspended this RFP due to uncertainty caused by the ongoing financial crisis, the economic recession and its impact on loads, and belief that ratepayers and the Company might get a better deal than the proposals submitted in the RFP as the year goes on and markets continue to adjust to the economic environment. Additionally, PacifiCorp also believes suppliers will be much more likely to secure financing once the banking sector has stabilized.

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[18] PacifiCorp's website for competitive solicitations: http://www.pacificorp.com/Article/Article62880.html.

PacifiCorp will monitor the market over the next six to eight months with the intention to lift the suspension, issue an Amendment to the RFP and request updated proposals from the existing bidders and new proposals. PacifiCorp also intends to refresh its benchmark proposals at that time.

Renewable Request for Proposal (RFP 2008R)

PacifiCorp issued RFP 2008R on January 31, 2008 for renewable resources of less than 100 MW for resources greater than five years in length, or greater than 100 MW for resources less than or equal to five years in length. The 2008R RFP solicited renewable resources that have a commercial operation date prior to December 31, 2009. On September 5, 2008, PacifiCorp executed a 20-year power purchase agreement with Duke Energy Corporation for the entire output of the 99-MW Campbell Hill project, located in Wyoming.

Renewable Request for Proposal (RFP 2008R-1)

PacifiCorp issued RFP 2008R-1 on October 6, 2008. This RFP solicited 500 MW of renewable generation projects—with no single resource greater than 300 MW—with on-line dates prior to December, 2011. An amendment to this RFP was filed in Utah on January 12, 2009 and in Oregon on January 8, 2009. Bidders for existing proposals that have been received will have an opportunity to update their pricing. The amendment also allows new bidders to participate. The amendment was filed and approved by the Oregon Public Utility Commission January 20, 2009. The Company has developed its shortlist of bidders, and anticipates making procurement decisions by July 2009. PacifiCorp also filed notices with state commissions regarding its intent to issue its next renewables RFP (2009R).

Demand-side Resources

The Company released a comprehensive demand-side management RFP (2008 DSM RFP) in November 2008. This RFP constitutes one of the items in PacifiCorp's IRP action plan, documented in the 2007 IRP Update report (June 2008, page 25). The 2008 DSM RFP requested bids on eighteen defined products: four Class 1 products and fourteen Class 2 products. The RFP also allowed for proposals on three non-defined products, one for Class 1 load management products, one for Class 2 energy efficiency products, and one for Class 3 price-responsive products. The non-defined product requests allowed bidders to propose products not initially identified in the RFP that they believe may be of benefit to the Company. Contracting for new products accepted under the 2008 DSM RFP will be concluded by mid-summer with regulatory approvals and implementation scheduled to begin the fourth quarter of 2009.

Other procurement work anticipated in 2009 includes the issuance of RFPs for program evaluations of legacy products, engineering resources in support of commercial, industrial and agricultural program delivery, and the procurement of ongoing irrigation load management services in Utah and Idaho.

4. TRANSMISSION PLANNING

PURPOSE OF TRANSMISSION

The basic purpose of PacifiCorp's bulk transmission network is to reliably transport electric energy from generation resources (generation or market purchases) to various load centers. There are several related benefits associated with a robust transmission network:

1. Reliable delivery of power to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably unscheduled outages.
3. Economic exchange of electric power among all systems and industry participants.
4. Development of economically feasible renewable generation in areas where it is best suited.
5. Protection against extreme market conditions where limited transmission constrains energy supply.
6. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff.
7. Increased capability and capacity to access Western energy supply markets.

PacifiCorp's transmission network is a critical component of the IRP process and is highly integrated with other transmission providers in the western United States. It has a long history of reliable service in meeting the bulk transmission needs of the region. Its purpose will become more critical in the future as energy resources become more dynamic and customer expectations become more demanding.

INTEGRATED RESOURCE PLANNING PERSPECTIVE

Transmission constraints and the ability to address capacity or congestion issues in a timely manner represent important planning considerations for ensuring that peak load and energy obligations are met on a reliable basis. The cycle time to add significant transmission infrastructure is often longer than adding generation resources or securing third party resources. Transmission additions must be integrated into regional plans and then permits must be obtained to site and construct the physical assets. Inadequate transmission capacity limits the utilities ability to access what would otherwise be cost effective generating resources.

Transmission assets tend to be long lived which go beyond a twenty-year planning horizon typically considered for resource planning. The result is a set of transmission assets modeled for least cost planning that addresses PacifiCorp's control area needs as well as enables a first-cut evaluation of the impacts of a large multi-state transmission project.

As discussed in the following sections, PacifiCorp is engaged in a significant transmission expansion effort called Energy Gateway that requires cooperative transmission planning with regional and sub-regional planning groups across the Western Interconnection. Transmission infrastructure will continue to play an important role in future IRP plans as segments are added due to Energy Gateway along with other system reinforcement projects.

INTERCONNECTION-WIDE REGIONAL PLANNING

Various regional planning processes have developed over the last several years in the Western Interconnection[19]. It is expected that, in the future, these processes will be the primary forums where major transmission projects are identified, evaluated, developed and coordinated. In the Western Interconnection, regional planning has evolved into a three tiered approach where an interconnection-wide entity, the Western Electricity Coordinating Council (WECC) conducts regional planning at a very high level, several sub-regional planning groups focus with greater depth on their specific areas and transmission providers perform local planning studies within their sub-region. This coordinated planning helps to insure that customers in the region are served reliably and at the least cost.

In 2006, WECC took on a larger and more defined responsibility for interconnection-wide transmission expansion planning under the Federal Energy Regulatory Commission’s Order 890. WECC’s role in meeting the region’s need for regional economic transmission planning and analyses is to provide impartial and reliable data, public process leadership, and analytical tools and services. The activities of WECC in this area are guided and overseen by a board-level committee and the Transmission Expansion Planning Policy Committee (TEPPC).

TEPPC’s three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions compliment but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

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

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

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[19] The Western Interconnection stretches from Western Canada South to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.

- Approving recommendations to improve the economic transmission expansion planning process.

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

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

Similar to the TEPPC activities and process at WECC, a similar process exists under the oversight of the Planning Coordination Committee which provides for the reliability aspects of transmission system planning.

Sub-regional Planning Groups

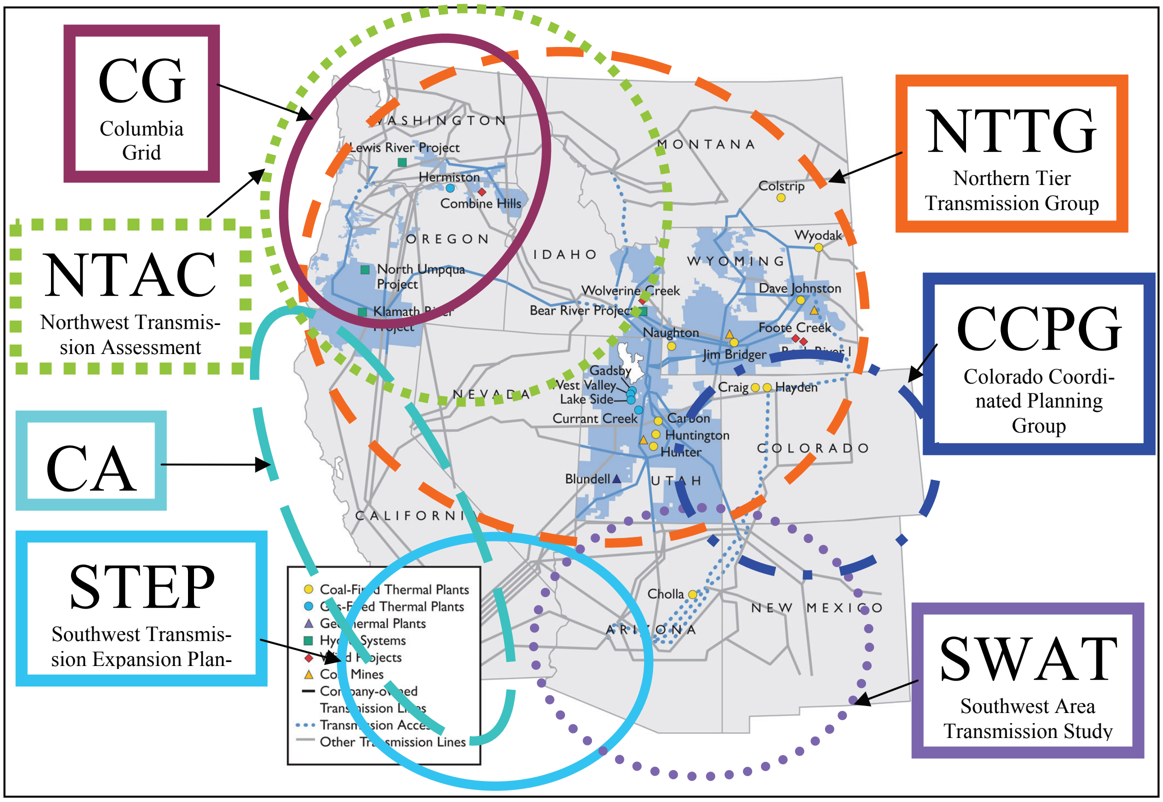
Recognizing that planning the entire western interconnection in one forum is impractical due to the overwhelming scope of work, a number of smaller sub-regional groups have been formed to address specific challenges in various areas of the interconnection. Generally all of these forums provide similar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

- **NTTG** – Northern Tier Transmission Group
- **CCPG** – Colorado Coordinated Planning Group
- **CG** – Columbia Grid
- **NTAC** - Northwest Transmission Assessment Committee
- **STEP** - Southwest Transmission Expansion Planning
- **SWAT** – Southwest Area Transmission Study
- **CA** – California Independent System Operator
- **WestConnect** – A southwest sub-regional planning group that includes participants from CCPG, SWAT and other utilities

PacifiCorp is one of the founding members of Northern Tier Transmission Group (NTTG). Originally formed in early 2007, NTTG has an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. The NTTG footprint includes approximately 2.7 million customers and more than 27,000 miles of transmission lines within Oregon, Washington, California, Idaho, Montana, Wyoming and Utah. In addition to PacifiCorp, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Idaho Power, Portland General Electric, and the Utah Associated Municipal Power Systems.

The geographical areas covered by these sub-regional planning groups are approximately shown in Figure 4.1 below:

Figure 4.1 – Sub-regional Transmission Planning Groups in the WECC



Energy Gateway

Since the last major transmission infrastructure construction in the 1970s and early 1980s, load growth and increased use of the western transmission system has steadily eroded the surplus capacity of the network. In the early 1990s when limited transmission capacity in high growth regions became more severe, low natural gas prices generally made adding gas fired generation close to load centers less expensive than transmission infrastructure additions. As natural gas prices started moving up in the year 2000, transmission construction became more attractive, but long transmission lead times to resource centers and rate recovery uncertainty suppressed new transmission investment.

Repeated sub-regional studies, including the Rocky Mountain Area Transmission Study dated September 2004, the Western Governor's Association Transmission Task Force Report dated May 2006 and the Northern Tier Transmission Group Fast Track Project Process in 2007 plus subsequent PacifiCorp planning studies concluded the critical need to alleviate transmission congestion and move transmission constrained energy resources to regional load centers.

The recommended bulk electric transmission additions for PacifiCorp took on a consistent footprint which is now known as Energy Gateway by establishing a triangle over Idaho, Utah and Wyoming with paths extending into Oregon and Washington.

Prior to 2007, PacifiCorp transmission activity was primarily focused on maintaining existing transmission reliability, executing queue studies, addressing compliance issues, and participating in shaping regional policy issues. Investments in main grid assets for load service, regional expansion or economic expansion to meet specific customer requests for service were addressed as transmission customers requested service.

New Transmission Requirements

Historically, transmission planning took place at the utility level and was focused on connecting specific utility generation resources to designated load centers. Under 888/889 Federal Energy Regulatory Commission rules, customer requests for transmission service were sporadic and uncoordinated with high levels of uncertainty in many markets which inhibited transmission investments.

Due to PacifiCorp's transmission system being a major component of the Western Interconnection, the Company has the responsibility to provide network customers adequate transmission capability that optimizes generation resources and provides reliable service both today and into the future. Based on current projections, loads and the dynamic blend of energy resources are expected to become more complex over the next twenty years which will challenge the existing capabilities of the transmission network.

In addition to ensuring sufficient capacity is available to meet the needs of its network customers, the Federal Energy Regulatory Commission in Order 890 encourages transmission providers such as PacifiCorp to plan and implement regional solutions for transmission reliability and expansion.

Based on the aggregate needs of PacifiCorp and others utilities in various sub-regional planning groups, a blueprint for transmission expansion was developed. The expansion plan is a culmination of prior studies and multiple utilities' integrated resource plans (PacifiCorp, Idaho Power, NorthWestern, and Portland General Electric) as well as identified potential plans of independent resource developers. It identifies a transmission expansion plan that will support multiple load centers, resource locations and resource types. In total the expansion plan, now referred to as Energy Gateway calls for the construction of numerous transmission segments – totaling approximately 2,000 miles.

The Energy Gateway blueprint uses a "hub and spoke" concept to most efficiently integrate transmission lines and collection points with resources and loads centers aimed at serving PacifiCorp customers while keeping in sight Regional and Sub Regional needs.

In addition to regulatory requirements for regional planning, future siting and permitting of new transmission lines will require significant participation and input from many stakeholders in the west. As part of new transmission line permitting PacifiCorp will have to demonstrate that several key requirements have been met; 1) the Company has satisfied an ongoing requirement for transmission to serve customers, 2) the Company is planning and building for the future and is obtaining corridors and mitigating environmental impacts prudently, and 3) that any projects being proposed economically meet the reliability and infrastructure needs of the region over all. This regional process and the Western Electricity Coordinating Council's planning process are considered critical to gaining wide support and acceptance for PacifiCorp's transmission expansion plan.

Reliability

PacifiCorp's transmission network is increasingly measured against new Federal Energy Regulatory Commission (FERC) / National Electric Reliability Corporation (NERC) mandatory reliability standards which require infrastructure to be in place in case of unplanned outage events. Mandatory compliance with the NERC planning standards is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment.[20] The majority of these new mandatory standards are the responsibility of the transmission owner.

NERC Planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy means the electric system needs to be able to supply aggregate electrical demand for customers at all times. Security means the electric system must withstand sudden disturbances or unanticipated loss of system elements. [21] Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

The ability to recover from system disturbances impacting main grid transmission often require accommodating multiple contingency scenarios which Energy Gateway helps facilitate along with other system reinforcement projects. There have been a number of main grid transmission outages in the latter part of 2007 resulting in curtailment of schedules, curtailments of interruptible loads and generation curtailments. These outages occurred on main grid paths and the ability to recover was severely limited because mitigation measures were electrically restricted due to lack of transmission capacity.

Resource Locations

As an extension of the 'hub and spoke' strategy, PacifiCorp must consider logical resource locations for the long-term based on environmental constraints, economical generation resources, and federal and state energy policies. PacifiCorp's primary energy resources in descending order are located in Utah, Wyoming, desert southwest and the west. Energy Gateway leverages the dynamic and future mix of energy resources and market access points at key locations and supports the Company's preferred resource portfolio.

Energy Gateway anticipates the availability and/or development of new resources including renewable energy resources in each of these key areas. The combination of resources cited in the 2008 IRP action plan and Energy Gateway support building to these resource locations.

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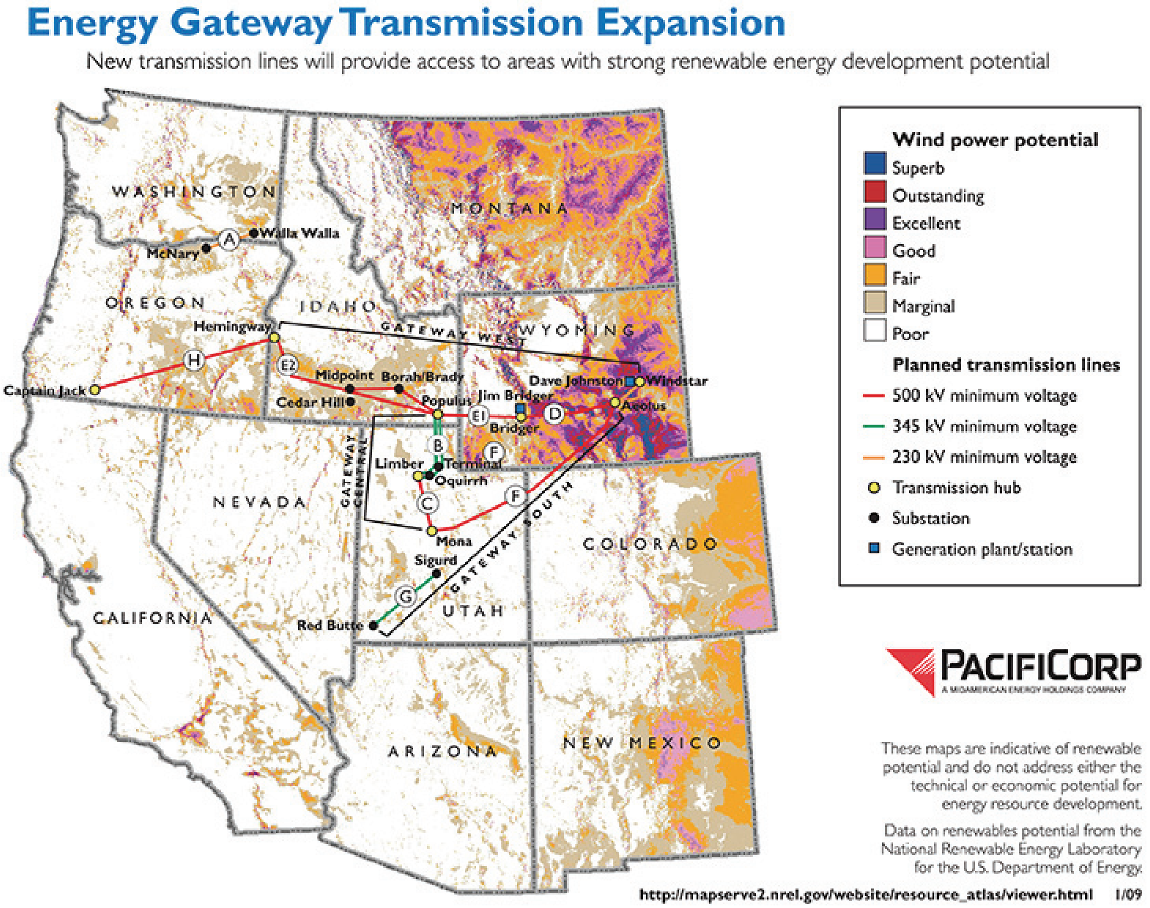
[20] Western Electricity Coordinating Council Reliability Criteria

[21] Western Electricity Coordinating Council Reliability Criteria

As a complement to the 'hub and spoke' concept, the Western Governors Association has been developing a process for identifying western renewable energy zones (WREZ). These renewable energy zones would be used to facilitate needed infrastructure to integrate and deliver large volumes of renewable energy to the west. Energy Gateway is well positioned access key renewable energy zones, primarily in Wyoming. The geographical areas for wind power potential are approximately shown in Figure 4.2 below.

Figure 4.2 – Western States Wind Power Potential Up to 25,000 Megawatts

(Class 5 Wind Locations or Higher)



These maps are indicative of renewable potential and do not address either the technical or economic potential for energy resource development.

Data on renewables potential from the National Renewable Energy Laboratory for the U.S. Department of Energy.

http://mapserve2.nrel.gov/website/resource_atlas/viewer.html 1/09

As another indicator of the importance of Energy Gateway to customers and the region, the Department of Energy sponsored a study through Idaho National Laboratories to assess the economic impact of not building transmission on the Pacific Northwest. The report was published in July 2008 and references:

> *"The model indicates that the PNWER (Pacific Northwest Economic Region) has a potential economic loss of $15B to $25B annually and 300,000 to 450,000 jobs over 30 years if just the one infrastructure transmission line project with the*

> *greatest economic impact is not built (i.e., BC to NorCal), and upwards of $55B to $85B annually and 1,750,000 jobs over 30 years if the five transmission line projects of greatest economic impact are not built (i.e., Alberta to PacNW Project, BC to NorCal,* ***Gateway West****, Southern Xing & I-5 Corridor Projects, and Mountain States Intertie). These transmission line projects … transport bulk power and are considered critical for access to preferred electrical generation by areas with high economic development and growth. Note, however, that even if these five projects come to fruition, the added power will not adequately serve the projected PNWER population increase, assuming consumption habits remain the same".*[22]
>
> *"Preliminary engineering review and analysis of planned transmission projects within the PNWER region resulted in the following initial ranking of the projects based on estimates of potential economic value of each project, the likelihood of project execution, the resource area(s) being accessed, the size of the project, and the value of the project to the transmission system as a whole. This analysis was subjective in nature and conducted for comparison purposes only before the full economic analysis and ranking was performed. This ranking was partially based on project listings in the IRPs, knowledge of potential generation resource areas and load centers, areas of transmission need, etc. As stated above, this report ranks evaluated projects according to the INL's assessment of their overall economic impact to PNWER according to the specific factors used in the evaluation. Other analyses may place different emphasis on different factors, resulting in a different overall ranking of projects. Despite these potential differences, all of the projects are considered valuable and necessary to adequately address growing electric power needs. The INL's preliminary ranking is shown in Table 1:*[23]

Table 1. Preliminary Ranking of Transmission Projects

#	*Preliminary Rank Project Name*	*#*	*Preliminary Rank Project Name*
1	*BC to NorCal*	*9*	*Inland Project (WY to Las Vegas)*
2	*Alberta to PacNW Project*	*10*	*Inland Project (MT to Las Vegas*
3	*Gateway West –* ***PacifiCorp***	*11*	*McNary – John Day*
4	*Southern Crossing*	*12*	*Southwest Intertie Project (SWIP) North*
5	*Gateway South –* ***PacifiCorp***	*13*	*Alstom to San Francisco Bay project (Alaska to Alstom project not included)*
6	*Gateway Central –* ***PacifiCorp***	*14*	*Montana Alberta Tie*
7	*Mountain States Intertie*	*15*	*Port Angeles-Juan de Fuca"*
8	*Interstate 5 Corridor Lines*		

ENERGY GATEWAY PRIORITIES

The greater part of the Energy Gateway project originates in Wyoming and Utah and migrates west to Oregon and Washington and south to southern Utah and Nevada. The Energy Gateway

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[22] Idaho National Laboratory: The Cost of Not Building Transmission, page vi

[23] Idaho National Laboratory: The Cost of Not Building Transmission, page 5

project takes into account the existing 2006 transaction commitments which include transmission facilities from southern Idaho to northern Utah (Path C), Mona to Oquirrh and Walla Walla to McNary.

PacifiCorp is actively pursuing the Energy Gateway transmission project under the following overarching key objectives:

- **Network customer driven** – Energy Gateway is primarily driven by PacifiCorp's retail and network customers' needs. Including Energy Gateway as a base allows PacifiCorp to move forward with the knowledge that over the coming years, transmission lines will be utilized to their fullest potential.
- **Support multiple resource scenarios** – The transmission expansion project must be able to accommodate a variety of future resource scenarios including meeting renewable portfolio standards, supporting natural gas fueled combustion turbines and market purchases, and recognizing that clean coal-based generation may re-emerge as a viable resource.
- **Consistent with past and current regional plans** – The proposed projects are consistent with a number of regional planning efforts. The need to expand transmission capacity has been known for years and should not be a surprise to the regional planning process and justification of need. The regional planning process should reduce the number of parties that may be publicly opposed to these projects due to the scrutiny placed on justification.
- **Get it built** – A significant barrier to achieving "steel in the ground" has historically been frustrated by lengthy multi-party negotiations related to planning and governance structure. Minimizing the impacts of these barriers through action-oriented objectives will be key to project success.
- **Secure the support of state and federal utility commissions for rate recovery** – Throughout the process, the project will seek input of state and federal regulators to ensure concerns are communicated early and addressed. The project should be undertaken in a manner that is acceptable to commissions and customers.
- **Protect the investment to the benefit of customers** – An appropriate balance must be struck to ensure that network customers do not subsidize third party use and ensure that PacifiCorp's long-term network allocation requirements are retained.

Phasing of Energy Gateway

PacifiCorp has been clear in its position regarding the initial announcement of Energy Gateway that significant infrastructure of new transmission capacity is needed to adequately serve PacifiCorp's existing and future loads over the long-term. The Company's position has not changed in this regard and requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South) of new transmission capacity to adequately serve its customers load and growth needs for the long-term.

PacifiCorp also recognized in its originally announced Energy Gateway Program the need and benefits of potentially "upsizing or scaling up" the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors, potential to reduce environmental impacts, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity.

PacifiCorp still believes there are viable expectations and reasons for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp believes that both short-term and long-term benefits exist as a result of upsizing the Energy Gateway Program and that existing barriers may be overcome at some future date. However; the Company must prudently move ahead now with steps necessary to serve its customers while keeping in sight these potential benefits perceived by upsizing.

PacifiCorp is proceeding with efforts regarding planning and rating requirements for the Energy Gateway Program which facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need and construction timing

The core transmission expansion plan will construct lines and stations required to deliver 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) of transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads. Additional stages may continue at some future date as determined by, economic, business and regulatory drivers that may be better defined in the upcoming years. Further expansion to the Desert Southwest will also be considered.

Each segment will be justified individually within the overall program. A combination of benefits including net power cost savings derived from the IRP, reliability, capital offsets for renewable resource development in low yield geographic regions and system loss reductions will be used to assess the viability of each segment.

The primary justification due to net power cost savings is derived from modeling alternative resource options under an assortment of forecast assumptions with and without Energy Gateway. The difference between the Energy Gateway build options and no transmission expansion yields a net power savings. Additional considerations listed above are considered on a segment-by-segment basis.

Each Energy Gateway segment will be reviewed again before significant commitments are made to ensure its justification. Therefore, depending on conditions or alternatives certain segments could be deferred or not constructed if not warranted. It is also reasonable to expect certain core segments will be justified in multiple scenarios. Segments will be reevaluated during each IRP cycle and annual business plan similar to generation/market resource plans to ensure they are required.

5. RESOURCE NEEDS ASSESSMENT

INTRODUCTION

This chapter presents PacifiCorp's assessment of resource need, focusing on the first 10 years of the IRP's 20-year study period, 2009 through 2018. The Company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicated when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

LOAD FORECAST

Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques. These models are driven by county and state level forecasts of employment and income that are provided by public agencies or purchased from commercial econometric forecasting services.[24] Appendix E provides additional details on the state-level forecasts.

Evolution and changes in Integrated Resource Planning Load Forecasts

Through the course of the 2008 integrated resource planning cycle, PacifiCorp relied on the November 2008 load forecast for the development of the load and resource balance and portfolio evaluations. Portfolio analysis started as early as June 2008 with preliminary load forecast and continued through December 2008. Under stable economic conditions, the Company would normally prepare one load forecast per year. However, the unstable and volatile economic conditions required the Company to update its load forecasts frequently to attempt to capture price and usage changes between June 2008 and November 2008. Because of the magnitude of the forecast changes and the Company's plan to align IRP filing with the Business Plan, the Company decided that it was prudent to incorporate latest load forecast updates in the IRP. Consequently, PacifiCorp's IRP analysis from November 2008 onward reflects the November 2008 load forecast.

In order to improve sales and load forecasting methods, capabilities, and accuracy, several improvements in the load forecasting approach were identified jointly by the Company and the Company's consultant, ITRON, and the load forecast methodology was changed to incorporate these improvements. Forecast improvements were driven primarily by six major changes in forecast assumptions. First, load research data was used to model the impact of weather on monthly retail sales and peaks by state by class. The Company collects hourly load data from a sample of customers for each class in each state. These data are primarily used for rate design, but they also

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

provide an opportunity to better understand usage patterns, particularly as they relate to changes in temperature. The greater frequency and data points associated with this hourly data make it better suited to capture load changes driven by changes in temperature than the monthly data used in the Company's prior forecasts.

Second, the time period used to define normal weather was updated from the National Oceanic and Atmospheric Administration's 30-year period of 1971-2000 to a 20-year time period of 1988-2007. The Company identified a trend of increasing summer and winter temperatures in the Company's service territory that was not being captured in the thirty year data. ITRON surveys have identified that many other utilities are also using more recent data for determining normal temperatures. Based on this review and on the recommendation from ITRON, the Company adopted a 20-year rolling average as the basis for determining normal temperatures. This better captures the trend of increasing temperatures observed in both summer and winter.

Third, the historical data period used to develop the monthly retail sales forecasts was updated to cover 1997-2007.

Fourth, monthly peaks were forecasted for each state using a peak model and estimated with historical data from 1990-2007. As an improvement to the forecasting process, the Company developed a model that relates peak loads to the weather that generated the peaks. This model allows the Company to better predict monthly and seasonal peaks. The peak model is discussed in greater detail in the following section.

Fifth, system line losses were updated to reflect actual losses for the 5-years ending December 31, 2007. The Company previously used the results of the most recent system line loss study, which was based on calendar-year 2001 data. The Company had observed that actual losses were higher than those from the previous line loss study. Investigation and discussions with the consultant who prepared the previous line loss study indicated that the previous study only reflected losses associated with retail load. Because there are also system losses associated with wholesale sales, the prior loss value was understated. The use of actual losses is a reasonable basis for capturing total system losses and has been incorporated in this forecast.

Finally, analyses were performed and adjustments made for the impact of current economic conditions. Because the model is estimated over a period of relative prosperity, it is necessary to make an explicit adjustment for the economic downturn, and hence the forecast was revised. In October 2008, the near-term forecast was adjusted downward to reflect the recent recession impacts mirroring load changes experienced in the previous recession (2001-2002). In the November update, the forecast was further adjusted downward in the Industrial sector for Utah (2010 onwards) and Wyoming (2009 onwards) to reflect the additional recession impacts.

In addition to these forecast methodology changes, energy efficiency (Class 2 DSM) was handled differently relative to past IRPs. Rather than treating Class 2 DSM as a decrement to the load forecast, PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model. To accomplish this, the load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM. The capacity expansion model then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by using the capacity expansion model, determines the cost-effective mix of Class 2 DSM for a given scenario. For retail load forecast reporting, PacifiCorp deducts the Class 2 DSM load reductions reflected in the 2008 IRP preferred portfolio from the original "pre-DSM" load forecast.

Modeling overview

The following section describes the modeling techniques used to develop the load forecast.

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential, commercial, irrigation, public street lighting, and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers.

The residential use-per-customer is forecasted by statistical end-use forecasting techniques. This approach incorporates end use information (saturation forecasts and efficiency forecasts) but is estimated using monthly billing data. Saturation trends are based on analysis of the Company's saturation survey data and efficiency trends are based on EIA forecasts that incorporate market forces as well as changes in appliance and equipment efficiency standards. Major drivers of the statistical end use based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

The commercial, irrigation, public street lighting, and sales to public authority use-per-customer forecast is developed using an econometric model. For the commercial class, sales per customer are forecasted using regression analysis techniques with non-manufacturing employment serving as the major economic driver in addition to weather related variables. For other classes, sales per customer are forecasted through regression analysis techniques using time trend variables.

The customer forecasts are generally based on a combination of regression analysis and exponential smoothing techniques using historical data from 1997 to 2007. For the residential class, the customer forecasts are developed using a regression model with Global Insight's forecast of the states' number of households serving as the major driver. For the commercial class, forecasts rely on a regression model with the forecasted residential customer numbers being used as the major driver. For other classes (irrigation, street lighting, and public authority), customer forecasts are developed based on exponential smoothing models.

The industrial sales forecast is developed for each jurisdiction using a model which is dependent on input for the Customer Account Managers (CAMs). The industrial customers are separated into three categories: existing customers that are tracked by the CAMs, new large customers or expansions by existing large customers, and industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if (1) they have a peak load of five MW or more or if (2) they have a peak load of one MW or more and have a history of large variations in their monthly usage. The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer. The account managers have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Projected loads associated with new customers or expansions of existing large customers are categorized into three groups. Tier 1 customers are those with a signed master electric service agreement ("MESA") or engineering material and procurement agreement ("EMPA"). When a customer signs a MESA or EMPA, this contractually commits the Company to provide services under the terms of agreement. Tier 2 includes customers with a signed engineering services agreement (ESA). This means that customer paid the Company to perform a study that determines what improvements the Company will need to make to serve the requested load. Tier 3 consists of customers who made inquiries but have not signed a formal agreement. Projected loads from customers in each of these tiers are assigned probabilities depending on project-specific information received from the customer.

Smaller industrial customers are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment serves as the major economic driver. The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories. The segments are forecasted differently within the industrial class because of the diverse makeup of the customers within the class.

After monthly energy by customer class is developed, hourly loads are estimated in two steps. First, PacifiCorp derives monthly and seasonal peak forecasts for each state. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables. These weather variables include the average temperature on the peak day and average daily temperatures for two days prior to the peak day. Second, hourly load forecasts for each state are obtained from the hourly load models using state-specific hourly load data and daily weather variables. Hourly load forecasts are developed using a model that incorporates the 20-year average temperatures, the actual weather pattern for a year, and day-type variables such as weekends and holidays. The model uses HDD (heating degree days) and CDD (cooling degree days) values for each of the twenty years and averages the results using a Rank and Average method instead of averaging by date as in the previous thirty-year process. This helps to incorporate both mild and extreme days in weather patterns, thereby more effectively representing the daily volatility in weather experienced during a typical year. Also, the method preserves the extreme temperatures and maps them to a year to produce a more accurate estimate of daily temperatures. The hourly load forecasts are adjusted for line losses and calibrated to monthly and seasonal peaks. After PacifiCorp develops the hourly load forecasts for each state, hourly loads are aggregated to the total Company system level. System coincident peaks are then identified as well as the contribution of each jurisdiction to those monthly system peaks.

The following sections describe the November 2008 energy and coincident peak load forecasts used for IRP portfolio modeling.

Energy Forecast

Table 5.1 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the forecast period 2009 through 2018.

Table 5.1 – Forecasted Average Annual Energy Growth Rates for Load

	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009-2018	2.1%	1.2%	0.7%	1.6%	2.5%	3.4%	1.5%	1.5%

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% percent annually from fiscal year 2009 to 2018. Table 5.2 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

Table 5.2 – Annual Load Growth forecasted (in Megawatt-hours) 2009 through 2018

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**61,558,392**	15,475,197	4,481,972	1,006,036	24,211,643	10,077,831	3,746,722	2,558,992
2010	**62,572,227**	15,488,359	4,490,263	1,036,284	24,766,082	10,422,330	3,784,242	2,584,666
2011	**63,979,543**	15,733,361	4,528,860	1,072,927	25,331,349	10,873,984	3,825,481	2,613,580
2012	**65,860,922**	16,096,835	4,564,434	1,108,124	26,227,765	11,341,534	3,875,330	2,646,900
2013	**67,602,494**	16,395,770	4,586,107	1,119,431	26,990,389	11,738,006	4,024,940	2,747,851
2014	**69,299,539**	16,648,638	4,620,452	1,128,072	27,811,230	12,117,111	4,142,098	2,831,937
2015	**70,735,798**	16,790,823	4,652,542	1,136,689	28,631,507	12,498,120	4,172,873	2,853,245
2016	**72,193,764**	16,979,579	4,692,854	1,148,202	29,355,209	12,926,718	4,211,552	2,879,649
2017	**73,110,441**	17,080,573	4,709,745	1,153,152	29,791,003	13,240,453	4,237,529	2,897,985
2018	**74,348,970**	17,281,372	4,752,289	1,165,356	30,363,899	13,581,557	4,278,351	2,926,146
Average Annual Growth Rate								
2009-18	**2.1%**	**1.2%**	**0.7%**	**1.6%**	**2.5%**	**3.4%**	**1.5%**	**1.5%**
2018-28	**1.2%**	**1.1%**	**0.9%**	**1.1%**	**1.6%**	**0.6%**	**0.9%**	**0.9%**
2009-28	**1.6%**	**1.2%**	**0.8%**	**1.3%**	**2.0%**	**1.9%**	**1.2%**	**1.2%**

System-Wide Coincident Peak Load Forecast

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

In the 1990's the annual system peak usually occurred in the winter. After 2000, the annual system peak has generally occurred in the summer. The system peak has switched to the summer as a result of several factors. First, the increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter has contributed to shift from a winter peak to a summer peak. This trend in space conditioning is expected to continue. Second, Utah with a summer peak that is relatively higher than the winter peak has been growing faster than the system. This growth also has contributed to a shift from a winter peak to a summer peaking system.

Total system load factor is expected to be relatively stable over the 2009 to 2018 time period. There are several factors working in opposite directions, leading to this result. First, the relatively high growth in high load factor industrial sales, particularly in Wyoming, tends to push up the system load factor. Second, as discussed above, the shift in space conditioning tends to push down the system load factor. And, third, efficiency standards such as the 2012 federal lighting standards also tend to push down the system load factor.

Table 5.3 – Forecasted Coincidental Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009-2018	**2.4%**	**1.6%**	**1.8%**	**1.9%**	**2.6%**	**3.1%**	**2.5%**	**3.0%**

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.7 percent and 1.6 percent, respectively, over the forecast horizon.

Table 5.4 below shows that for the same time period the total peak is expected to grow by 2.4 percent.

Table 5.4 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**10,143**	2,463	761	167	4,509	1,253	628	362
2010	**10,360**	2,476	768	174	4,626	1,290	654	372
2011	**10,631**	2,526	780	181	4,708	1,354	682	401
2012	**10,978**	2,579	816	187	4,854	1,394	716	431
2013	**11,261**	2,638	800	190	5,008	1,440	748	437
2014	**11,451**	2,695	815	189	5,174	1,485	691	402
2015	**11,730**	2,728	826	191	5,322	1,530	718	414
2016	**12,032**	2,763	836	194	5,458	1,577	759	446
2017	**12,251**	2,795	846	199	5,568	1,616	773	454
2018	**12,522**	2,836	889	197	5,686	1,656	786	473
Average Annual Growth Rate								
2009-2018	**2.4%**	**1.6%**	**1.8%**	**1.9%**	**2.6%**	**3.1%**	**2.5%**	**3.0%**
2018-2028	**1.4%**	**1.4%**	**1.1%**	**1.2%**	**1.8%**	**0.7%**	**0.9%**	**0.6%**
2009-2028	**1.9%**	**1.5%**	**1.4%**	**1.5%**	**2.2%**	**1.9%**	**1.7%**	**1.8%**

One noticeable aspect of the states contribution to the system coincidental peak forecast is that they do not smoothly increase from year to year, and in Idaho, the contribution to system coincident peak decreases in 2014.

Idaho's contribution to the coincident peak is forecasted to decrease in 2014 even though the total system peak increases from year to year. This behavior occurs because state level coincident peaks do not occur at the same time as the system level coincident peak, and because of differences among the states with regard to load growth and customer mix. While each state's peak load is forecast to grow each year when taken on its own, its contribution to the system coincident peak will vary since the hour of system peak does not coincide with the hour of peak load in each state. As the growth patterns of the class and states change over time, the peak will move within the season, month or day, and each state's contribution will move accordingly, sometimes resulting in a reduced contribution to the system coincident peak from year to year in a particular state. This is seen in a few areas in the forecast as well as experienced in history. For example, the Idaho state load is driven in the summer months by the activity in the irrigation class. The planting and irrigating practices usually cause this state to experience the maximum load in late June or early July. This load then quickly decreases week by week. Consequently, there can be as much as 300 MW of load difference between the maximum load and the loads during the last weeks of July.

Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different patterns than the system coincident hourly load. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. Table 5.5 reports the jurisdictional peak demand growth over the forecast horizon.

Table 5.5 – Jurisdictional Peak Load forecast, 2009 through 2018 (Megawatts)

Year	OR	WA	CA	UT	WY	ID	SE-ID
2009	2,781	850	187	4,678	1,343	776	434
2010	2,795	856	197	4,796	1,371	785	448
2011	2,825	863	204	4,875	1,419	795	453
2012	2,854	876	210	5,033	1,473	806	485
2013	2,914	884	212	5,202	1,532	835	491
2014	2,958	897	214	5,360	1,581	858	497
2015	2,989	909	216	5,522	1,631	867	493
2016	3,010	919	218	5,662	1,680	874	511
2017	3,033	931	221	5,775	1,729	881	518
2018	3,059	942	223	5,902	1,776	890	536
Average Annual Growth Rate							
2009-2018	**1.1%**	**1.1%**	**2.0%**	**2.6%**	**3.2%**	**1.5%**	**2.4%**
2018-2028	**1.3%**	**1.4%**	**1.2%**	**1.8%**	**0.7%**	**0.9%**	**0.9%**
2009-2028	**1.2%**	**1.3%**	**1.6%**	**2.2%**	**1.8%**	**1.2%**	**1.6%**

EXISTING RESOURCES

For the forecasted 2009 summer peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 13,145 MW. Table 5.6 provides anticipated system peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2009.

Table 5.6 – Capacity Ratings of Existing Resources

Resource Type	MW *	Percent
Pulverized Coal	6,128	46.6%
Gas-CCCT	2,025	15.4%
Gas-SCCT	380	2.9%
Hydroelectric	1,450	11.0%
Class 1 DSM **	345	2.6%
Renewables	247	1.9%
Purchase ***	2,061	15.7%
Qualifying Facilities	271	2.1%
Interruptible	237	1.8%
Total	**13,145**	**100%**

* Represents the capacity available at the time of system peak.
** Class 1 Demand-side management is PacifiCorp's dispatchable load control.
*** Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

In September 2008, the Chehalis combine cycle combustion turbine plant began operations adding 509 MW of summer peak capacity to the PacifiCorp thermal fleet. Table 5.7 lists existing PacifiCorp's coal fired thermal plants and table 5.8 lists existing natural gas fired plants. As a modeling assumption, plant retirements were based on the Company's 2007 depreciation study. The end of the depreciable life of Gadsby units 1-3 is currently 2017, while the depreciable life for Carbon units 1 and 2 is 2020. No thermal plants are currently scheduled for retirement. Plant retirement decisions will be based on an assessment of plant economics that considers the cost for replacement power given environmental compliance requirements, market conditions, and other factors.

Table 5.7 – Coal Fired Plants

Plant	PacifiCorp Percentage Share	State	Average Net Maximum Capacity
Carbon 1	100%	Utah	67.0
Carbon 2	100%	Utah	105.0
Cholla 4	100%	Arizona	395.0
Colstrip 3	10%	Montana	74.0
Colstrip 4	10%	Montana	74.0
Craig 1	19%	Colorado	82.5
Craig 2	19%	Colorado	82.5
Dave Johnston 1	100%	Wyoming	106.0
Dave Johnston 2	100%	Wyoming	106.0

Plant	PacifiCorp Percentage Share	State	Average Net Maximum Capacity
Dave Johnston 3	100%	Wyoming	220.0
Dave Johnston 4	100%	Wyoming	330.0
Hayden 1	24%	Colorado	45.1
Hayden 2	13%	Colorado	33.0
Hunter 1	94%	Utah	403.1
Hunter 2	60%	Utah	259.3
Hunter 3	100%	Utah	460.0
Huntington 1	100%	Utah	445.0
Huntington 2	100%	Utah	450.0
Jim Bridger 1	67%	Wyoming	353.3
Jim Bridger 2	67%	Wyoming	353.3
Jim Bridger 3	67%	Wyoming	353.3
Jim Bridger 4	67%	Wyoming	353.3
Naughton 1	100%	Wyoming	160.0
Naughton 2	100%	Wyoming	210.0
Naughton 3	100%	Wyoming	330.0
Wyodak	80%	Wyoming	268.0

Table 5.8 – Natural Gas Plants

Coal-fueled	PacifiCorp Percentage Share	State	Average Net Maximum Capacity
Currant Creek	100%	Utah	541
Gadsby 1	100%	Utah	60
Gadsby 2	100%	Utah	75
Gadsby 3	100%	Utah	100
Gadsby 4	100%	Utah	40
Gadsby 5	100%	Utah	40
Gadsby 6	100%	Utah	40
Hermiston 1 *	50%	Oregon	124
Hermiston 2 *	50%	Oregon	124
Lake Side	100%	Utah	544
Chehalis	100%	Washington	520

* Remainder of Hermiston plant under purchase contract by the Company for a total of 248 MW.

Renewables

PacifiCorp's renewable resources, presented by resource type, are described below.

Wind

PacifiCorp acquires wind power from owned plants and various purchase agreements. Since the 2007 IRP, PacifiCorp has acquired several large wind resources including Seven Mile I and II, and Marengo II, Glenrock I and III, and Rolling Hills. These projects came on line in 2008. The

Company also entered into 20-year power purchase agreements for the total output of several projects including Mountain Wind I and II and Spanish Fork in 2008, Duke Energy's (Three Buttes Windpower LLC) Campbell Hill project and Oregon Wind Farm I in 2009, and Oregon Wind Farm II in 2010.

Table 5.9 shows existing and firm planned wind facilities owned by PacifiCorp, while Table 5.10 shows existing wind power purchase agreements. For the year ended December 31, 2008, PacifiCorp's total installed wind capacity totaled 802 MW, along with 315 MW of purchased power capacity.

Table 5.9 – PacifiCorp-owned Wind Resources

Utility-Owned Wind Projects	Capacity (MW)	In-Service Year	State
Foote Creek I [1/]	33.0	2005	WY
Leaning Juniper	100.5	2006	OR
Goodnoe Hills East Wind	94.0	2007	WA
Marengo	140.4	2007	WA
Glenrock Wind I	99.0	2008	WY
Glenrock Wind III	39.0	2008	WY
Marengo II	70.2	2008	WA
Rolling Hills Wind	99.0	2008	WY
Seven Mile Hill Wind	99.0	2008	WY
Seven Mile Hill Wind II	19.5	2008	WY
High Plains (Under Construction)	99.0	2009	WY
TOTAL	**893.0**		

[1/] Net total capacity for Foote Creek I is 41 MW.

Table 5.10 – Wind Power Purchase Agreements

Power Purchase Agreements	Capacity (MW)	In-Service Year	State
Foote Creek III	25.2	2005	WY
Foote Creek IV	16.8	2005	WY
Wolverine Creek	64.5	2005	ID
Rock River I	50.0	2006	WY
Mountain Wind Power I	60.0	2008	WY
Mountain Wind Power II	79.5	2008	WY
Spanish Fork	18.9	2008	UT
Three Buttes Wind Power (Duke)	99.0	2009	WY
Oregon Wind Farm I	45.0	2009	OR
Oregon Wind Farm II	20.0	2010	OR
TOTAL	**478.9**		

PacifiCorp also has wind integration, storage and return agreements with Bonneville Power Administration, Eugene Water and Electric Board, Public Service Company of Colorado, and Seattle City Light.

Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007.

Biomass

Since the 2007 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples are found in Table 5.11.

Table 5.11 – Existing Biomass resources

Biomass Projects	Capacity (MW)	State
Biomass One, LLC	25.0	Oregon
Davis County Waste Management	1.6	Utah
Douglas Country Forest Products	6.25	Oregon
DR Johnson Lumber Company	8.3	Oregon
Evergreen BioPower	10.0	Oregon
Roseburg Forest Products	20.0	Oregon
Rough & Ready Lumber	1.28	Oregon
Simplot Phosphates, LLC	9.5	Wyoming

Biogas

Since the 2007 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples are found in Table 5.12.

Table 5.12 – Existing Biogas resources

Biogas Project	Capacity (MW)	State
Sunderland Dairy	0.15	Utah
Wadeland South, LLC	0.125	Utah
Weber County, State of Utah	0.95	Utah
Hill Air Force Base	2.5	Utah
Ballard Hog Farms Inc	0.05	Utah
George Deruyter & Sons Dairy	1.2	Washington
Finley BioEnergy	4.8	Oregon
Oregon Environmental Industries	3.2	Oregon

Solar

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

Hydroelectric Generation

PacifiCorp owns or purchases 1,450 MW of hydroelectric generation. These resources account for approximately 11 percent of PacifiCorp's total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. Hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

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

PacifiCorp has added approximately 5 MW of additional capacity to its hydroelectric portfolio since the release of the 2007 IRP. This additional capacity is found in Table 5.13.

Table 5.13 – Hydroelectric additions

Hydroelectric Project	Capacity (MW)	State
Bell Mountain Power	0.45	Idaho
City of Albany, Dept of Public Works	0.5	Oregon
Cottonwood Hydro	0.85	Utah
Curtiss Livestock	0.075	Oregon
Loyd Fery Farms	0.04	Oregon
Mountain Energy	0.05	Oregon
Roush Hydro, Inc	0.08	Oregon
Yakima Tieton	2.95	Washington

Table 5.14 provides an operational profile for each of PacifiCorp's hydroelectric generation facilities. The dates listed refer to a calendar year.

Table 5.14 – Hydroelectric Generation Facilities – Nameplate Capacity as of January 2009

Plant	PacifiCorp Share (MW)	State	License Expiration Date	Retirement Date
West				
Bigfork	4.15	Montana	2053	2053
Clearwater 1	15.00	Oregon	2038	2038
Clearwater 2	26.00	Oregon	2038	2038
Copco 1	20.00	California	2006	2046

Plant	PacifiCorp Share (MW)	State	License Expiration Date	Retirement Date
Copco 2	27.00	California	2006	2046
East Side	3.20	Oregon	2006	2016
Fish Creek	11.00	Oregon	2038	2038
Iron Gate	18.00	California	2006	2046
JC Boyle	97.98	Oregon	2006	2046
Lemolo 1	31.99	Oregon	2038	2038
Lemolo 2	33.00	Oregon	2038	2038
Merwin	136.00	Washington	2058	2058
Rogue	46.76	Oregon	Various	Various
Slide Creek	18.00	Oregon	2038	2038
Soda Springs	11.00	Oregon	2038	2038
Swift 1	240.00	Washington	2058	2058
Toketee	42.50	Oregon	2038	2038
West Side	0.60	Oregon	2006	2016
Yale	134.00	Washington	2058	2058
Small West Hydro*	18.11	CA/OR/WA	Various	Various
East				
Bear River	108.73	ID/UT	Various	Various
Small East Hydro**	33.85	ID/UT/WY	Various	Various

* Includes Bend, Condit, Fall Creek, and Wallowa Falls

** Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock.

Note: Operational Capacity may differ from Nameplate Capacity due to operating conditions.

Hydroelectric Relicensing Impacts on Generation

Table 5.15 lists the estimated impacts to average annual hydro generation from FERC license renewals. PacifiCorp assumed that all hydroelectric facilities currently involved in the relicensing process will receive new operating licenses, but that additional operating restrictions imposed in new licenses, such as higher bypass flow requirements, will reduce generation available from these facilities.

Table 5.15 – Estimated Impact of FERC License Renewals on Hydroelectric Generation

Year	Lost Generation (MWh)
2009	160,356
2010	160,356
2011	160,356
2012	195,560
2013	195,560
2014	195,560
2015	338,917

Year	Lost Generation (MWh)
2016	415,328
2017	415,328
2018	413,435
2019	415,566
2020	415,566
2021	415,566
2022	415,566
2023	415,566
2024	415,566
2025	415,566
2026	415,566
2027	415,566
2028	415,566

Note: Excludes the decommissioning of Condit, Cove, Powerdale, and American Fork.

Demand-side Management

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

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

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

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

- **Class 4 DSM: Resources from energy efficiency education and non-incentive based voluntary curtailment programs/communications/pleas** – Class 4 programs resources may be in the form of energy and/or capacity reductions. The reductions are typically achieved from voluntary actions taken by customers, behavior changes, to save energy and/or reduce costs, benefit the environment or in response to public or utility company pleas to conserve or shift their usage to off peak hours. Program savings are difficult to measure and in many cases tend to vary over time. While not specifically relied upon in resource planning, Class 4 savings appear in historical load data therefore into resource planning through the plan load forecasts. The value of Class 4 DSM is long-term in nature. Class 4 programs help foster an understanding and appreciation as to why utilities seek customer participation in Class 1, 2 and 3 programs, as well provide a foundational understanding of how to use energy wisely. Program examples include Utah's PowerForward program, Company brochures with energy savings tips, customer news letters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Do the bright thing" and "Let's turn the answers on". Studies have shown potential savings up to 15% from behavior changes[25], especially when coupled with complimentary DSM programs to assist customers with a portion of the actions taken.[26] Although these behavior savings are often difficult and costly to track and measure, enough studies have measured their effects to expect at least a very modest degree of savings (equal to or greater than those expected to be acquired through DSM programs; e.g. 1+%) to be realized and reflected in customer usage and future load forecasts.

PacifiCorp has been operating successful DSM programs since the late 1980s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the Company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Company investments continue to increase year on year with 2008 investments exceeding $76

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[25] Lynn Fryer Stein, "California Information Display Pilot Technology Assessment" (December 2004), prepared by Primen Inc., for Southern California Edison.

[26] John Green and Lisa A. Skumatz, "Evaluating the Impacts of Education/Outreach Programs: Lessons on Impacts, Methods and Optimal Education, "paper presented at the American Council for an Energy Efficient Economy summer Study on Energy Efficiency in Buildings (2000).

million (all states). Work continues on the expansion of program portfolios in the states of Utah, Washington, Idaho and California. In late 2008 the Company received approval to begin offering DSM programs to Wyoming customers beginning in January 2009. In Oregon the Company is working closely with the Energy Trust of Oregon on helping to identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and Company support in pursuit of DSM resource targets.

The following represents a brief summary of the existing resources by class.

Class 1 Demand-side Management
Currently there are four Class 1 programs running across PacifiCorp's six state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program; Idaho's and Utah's scheduled firm irrigation load management programs; Idaho's and Utah's dispatchable irrigation load management programs; and special contract curtailment agreements with large business customers. In 2008 the programs provided approximately 560 megawatts of Class 1 DSM program resources during the highest summer peak load hours.

Class 2 Demand-side Management
The Company currently manages thirteen distinct Class 2 products, many of the products are offered in multiple states. In all, the combination of Class 2 programs across the Company's six state service area total thirty-four. The cumulative historical energy and capacity savings (1992-2008) associated with Class 2 DSM program activity has accounted for nearly 3.4 million megawatt hours and over 600 megawatts of load reductions.

Class 3 Demand-side Management
The Company has numerous Class 3 programs currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted rates (Utah), residential year-around inverted rates (California, Oregon, and Washington) and Energy Exchange programs (Oregon, Utah, Idaho, Wyoming and Washington). Savings associated with these programs are captured within the Company's load forecast, with the exception of the more immediate call-to-action programs like Energy Exchange and Utah's PowerForward programs. The impacts of these programs are thus captured in the integrated resource planning framework. Energy Exchange and Utah's PowerForward are examples of Class 3 programs relied upon as reliability resources as opposed to base resources. System-wide participation in metered time-of-day and time-of-use programs as of December 31, 2008 was about 21,700 customers, up from about 21,200 in 2006. Approximately 1.28 million residential customers—89% of the Company's residential customer base—are currently subject to inverted rate plans either seasonally or year-around.

PacifiCorp continues to evaluate Class 3 programs for applicability to long-term resource planning. As discussed in Chapter 6, five additional programs were provided as resource options in preliminary IRP modeling scenarios.

Class 4 Demand-side Management
Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts, bill messages,

newsletters, school education programs, and personal contact. Specific firm load reductions due to Class 4 DSM activity will show up in Class 2 DSM program results and non-program/documented reductions in the load forecast over time.

Table 5.16 summarizes the existing DSM programs, and describes how they are accounted for as planned resources.

Table 5.16 – Existing DSM Summary, 2009-2018

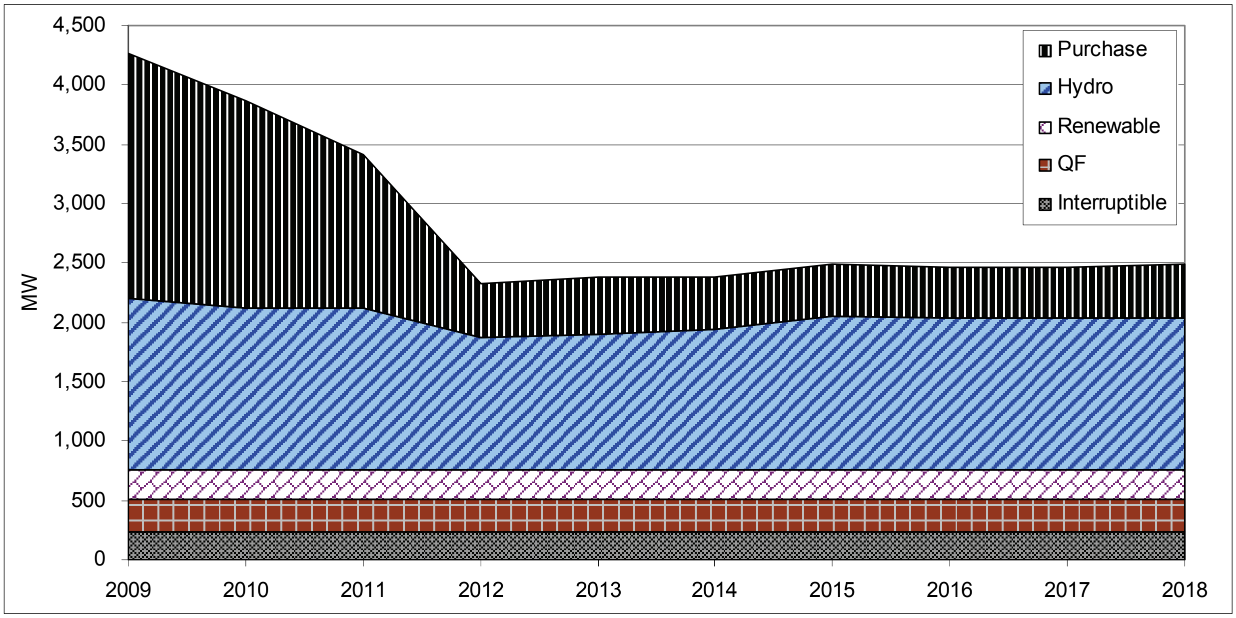
Program Class	Description	Energy Savings or Capacity at Generator	Included as Base Resources for 2009-2018 Period
1	Residential/small commercial air conditioner load control	100 MW summer peak	Yes
	Irrigation load management	220 MW summer peak	Yes
	Interruptible contracts	237 MW	Yes
2	Company and Energy Trust of Oregon programs	483 MWa and 908 MW (2008 IRP selections)	Yes
3	Energy Exchange	0-37 MW (assumes no other Class 3 competing products running)	No, leveraged as economic and reliability resource dependent on market prices/system loads
	Time-based pricing	MWa/MW unavailable 22.,000 customers	No, historical behavior captured in load forecast
	Inverted rate pricing	MWa/MW unavailable 1.28 million residential	No, historical behavior captured in load forecast
4	PowerForward	0-80 MW summer peak	No, leveraged as economic and reliability resource dependent on market prices/system loads
	Energy Education	MWa/MW unavailable	No, captured in load forecast over time and other Class 1 and Class 2 program results

Power Purchase Contracts

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

Figure 5.1 presents the contract capacity in place for 2008 through 2018 as of January 2009. As shown, major capacity reductions in purchases and hydro contracts occur. (For planning purposes, PacifiCorp assumes that current qualifying facility and interruptible load contracts are extended to the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 5.1 – Contract Capacity in the 2008 Load and Resource Balance

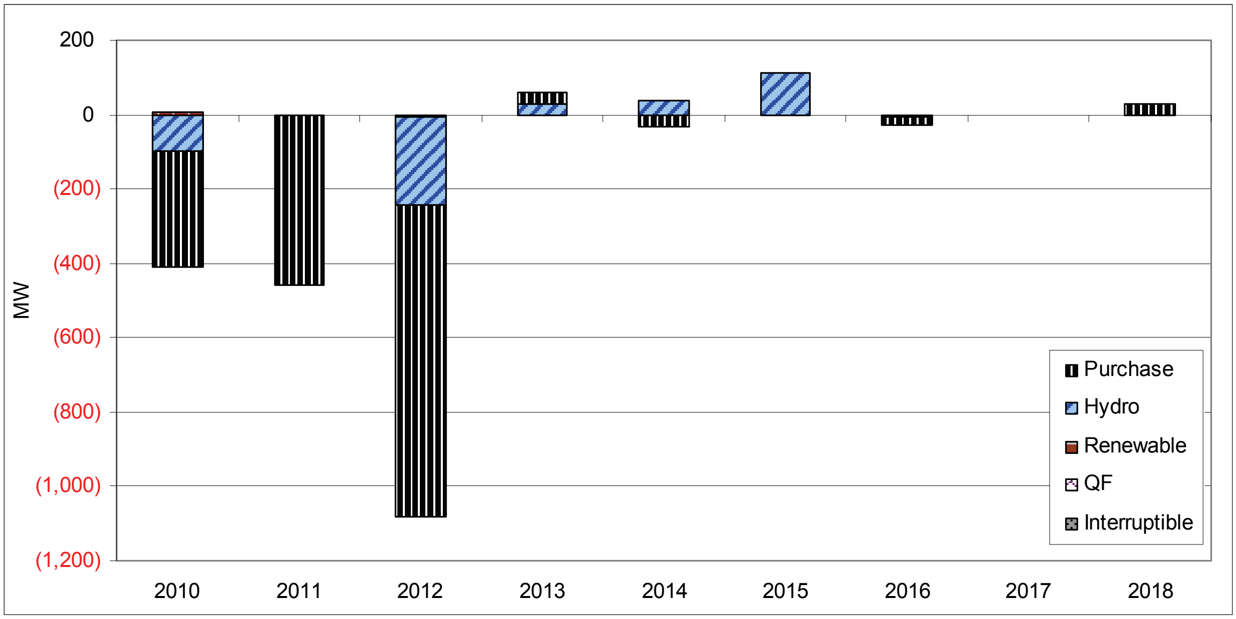


Listed below are the major contract expirations expiring between the summer 2011 and summer 2012:

BPA Peaking	575 MW
Morgan Stanley	100 MW
Morgan Stanley	100 MW
Colockum Capacity Exchange	108 MW
Rocky Reach	65 MW
Grant Displacement	63 MW

Figure 5.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

Figure 5.2 – Changes in Contract Capacity in the Load and Resource Balance



LOAD AND RESOURCE BALANCE

Capacity and Energy Balance Overview

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

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2009-2018) of the planning horizon. The peak load and the firm sales were added together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm-capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin, and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2009-2018). The average obligation (load plus sales) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

Capacity and energy balance information is reported for two scenarios: with the Lake Side II combined-cycle plant included as a firm planned resource in 2012, and Lake Side II excluded as a resource, resulting in a larger capacity deficit beginning in that year.

Load and Resource Balance Components

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

Existing Resources

The firm capacities of the existing resources are shown in Table 5.6 by resource category and summed to show the total available existing resource capacity for the east, west and for the PacifiCorp system. A description of each of the resource categories follows:

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

- **Hydro**. This category includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system peak, an approach consistent with current WECC capacity reporting practices. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. The energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation, are also accounted for. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

  The Utah commission, in its 2007 IRP acknowledgment order, directed the Company to investigate the hydro capacity accounting methodology currently under consideration for regional resource adequacy reporting purposes in the Pacific Northwest. This accounting methodology extends the one-hour sustained peaking period to the six highest load hours over three consecutive days of highest demand. This sustained peaking-period definition was adopted in 2008 by the Northwest Power and Conservation Council (NPCC) as part the capacity resource adequacy standard developed by the Pacific Northwest Resource Adequacy Forum. The hydro sustained peak capacity methodology is still being evaluated to work out certain methodology details and to determine how best to implement it on a regional basis.

The Pacific Northwest Resource Adequacy Forum hired a consultant to conduct the study, which is expected to be completed by the end of 2009.

PacifiCorp conducted a cursory analysis of hydro resource capacity using the NPCC sustained peaking-period definition. The impact of moving from a one-hour sustained peaking period to an 18-hour period was found to be negligible.

- **Demand-Side Management (DSM).** In 2009, there are projected to be about 345 megawatts of Class 1 demand-side management programs included as existing resources. These are further projected to increase to 525 MW by 2018. Both the capacity balance and the energy balance count DSM programs by program capacity. DSM resources directly curtail load and thus planning reserves are not held for them.

- **Renewable.** This category contains one geothermal project, 21 existing wind projects and two planned wind projects. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. Project-specific capacity credits for the wind resources were statistically determined. Wind energy is counted according to hourly generation data used to model the projects.

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

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

- **Interruptible.** There are three east-side load curtailment contracts in this category. These agreements with Monsanto, MagCorp and Nucor provide 237 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them.

Obligation

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

- **Load**. The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The energy balance counts the load as an average of monthly time-of-day energy (MWa).

  Due to new federal lighting standards being implemented under the Energy Policy Act of 2005, the load forecast required adjustment because lighting efficiency measures were embedded in the Class 2 DSM supply curves provided to PacifiCorp. Increasing the load forecast to account for this available energy efficiency "supply" ensures that an appropriate quantity of Class 2 DSM is selected by the capacity expansion model. Table 5.17 shows the impact of the hourly energy adjustments to the annual system coincident peak loads used in the 10-year capacity load and resource balance. (Note that this upward load adjustment applies only for capacity expansion modeling purposes. The Company's official load forecast is reported net of this DSM adjustment.)

Table 5.17 – Federal Lighting Standard Impact on System Peak loads

Year	Federal Lighting Standard Adjustment (MW)	System Coincident Peak Prior to Adjustment (MW)	Adjusted System Coincident Peak (MW)
2009	6.3	10,143	10,150
2010	10.3	10,360	10,371
2011	8.5	10,631	10,640
2012	12.2	10,978	10,991
2013	20.3	11,261	11,281
2014	50.8	11,451	11,501
2015	69.2	11,730	11,798
2016	94.1	12,032	12,127
2017	132.7	12,251	12,384
2018	151.6	12,522	12,674
2019	144.5		
2020	173.1		
2021	174.6		
2022	200.9		
2023	217.7		
2024	226.2		
2025	232.0		
2026	234.1		
2027	239.4		
2028	245.0		

- **Sales**. This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Reserves

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

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

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

- **Non-owned reserves**. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. This amounts to an annual reserve obligation of about 7 megawatts and 70 megawatts on the west and east-sides, respectively.

Position

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

Reserve Margin

The reserve margin is the ratio of existing resources to the obligation. A positive reserve margin indicates that existing resources exceeds obligation. Conversely, a negative reserve margin indicates that existing resources do not meet obligation. If existing resources equals the obligation, then the reserve margin is 0%. It should be pointed out that the reserve margin can be negative when the corresponding position is non-negative. This is because the reserve margin is measured relative to the obligation, while the position is measured relative to the obligation plus reserves.

Capacity Balance Determination

Methodology

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

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

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

Obligation *= Load + Sales*

The amount of reserves to be added to the obligation is then calculated. This is accomplished by first removing the firm purchase and load curtailment components of the existing resources from the obligation. This resulting net obligation is then multiplied by the planning reserve margin.

The non-owned reserves are then added to this result to yield the megawatts of required reserves. The formula for this calculation is the following:

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

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

Capacity Position *= Existing Resources – Obligation – Reserves*

Firm capacity transfers from PacifiCorp's western to eastern control areas are reported for the east capacity balance, while capacity transfers from the eastern to western control areas are reported for the west capacity balance. Capacity transfers represent the optimized control area interchange at the time of the system coincident peak load as determined by the System Optimizer model.[27]

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2007 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Commitment.** In the 2007 IRP, 400 megawatts of the overall 1,400-megawatt commitment are included in the load and resource balance. The remaining 1,000 megawatts were treated as part of the overall wind resource potential evaluated in portfolio modeling. In the 2008 IRP, there are 263 MW of firm planned wind projects included in the load and resource balance.

- **Coal plant turbine upgrades.** The current load and resource balance assumes 162 MW of coal plant turbine upgrades, which is down from the 202 MW assumed in the 2007 IRP Update Report.

Capacity Balance Results

Table 5.18 shows the annual capacity balances and component line items using a target planning reserve margin of 12 percent to calculate the planning reserve amount. (Capacity balance information with Lake Side II included as a planned resource in 2012 is provided in Appendix H.) Balances for the system as well as PacifiCorp's east and west control areas are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) For comparison purposes, Table 5.19 shows the system-level capacity balance assuming a 15 percent planning reserve margin.

Figures 5.3 through 5.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The decrease in resources in 2008

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[27] West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

is caused by the expected expiration of the West Valley lease agreement. The slight increase in 2009 is due to executed front office transactions and an increase in the curtailment portion of the Monsanto contract. The large decrease in 2012 is primarily due to the expiration of the BPA peaking contract in August 2011. Additionally, Figure 5.4 highlights a decrease in obligation in the west starting in 2014 attributable to the expiration of the Sacramento Municipal Utility District and City of Redding power sales contracts.

Table 5.18 – System Capacity Loads and Resources (12% Target Reserve Margin)

Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East										
Thermal	5,983	5,998	6,025	6,066	6,066	6,078	6,079	6,087	6,088	5,863
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
QF	151	151	151	151	151	151	151	151	151	151
Interruptible	237	237	237	237	237	237	237	237	237	237
Transfers	1,150	952	602	422	440	230	490	504	265	414
East Existing Resources	8,910	8,572	8,284	7,975	8,003	7,814	8,082	8,093	7,865	7,800
Load	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	7,538	7,717	7,908	8,151	8,388	8,524	8,774	9,048	9,150	9,355
Planning reserves	745	785	803	853	880	895	924	958	969	993
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	815	855	874	923	951	966	995	1,029	1,040	1,063
East Obligation + Reserves	8,352	8,572	8,781	9,074	9,339	9,490	9,769	10,077	10,190	10,418
East Position	558	1	(498)	(1,099)	(1,336)	(1,676)	(1,686)	(1,984)	(2,325)	(2,619)
East Reserve Margin	19%	12%	6%	(1%)	(4%)	(8%)	(7%)	(10%)	(13%)	(16%)
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydro	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
DSM	-	-	-	-	-	-	-	-	-	-
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
QF	120	120	120	120	120	120	120	120	120	120
Transfers	(1,152)	(953)	(603)	(422)	(442)	(228)	(489)	(504)	(263)	(415)
West Existing Resources	4,233	4,242	4,150	3,462	3,513	3,729	3,580	3,558	3,783	3,656
Load	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	3,892	3,912	3,780	3,845	3,896	3,980	3,927	3,932	4,001	4,086
Planning reserves	310	325	363	448	450	464	458	459	467	474
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	316	332	370	454	457	471	464	465	473	480
West Obligation + Reserves	4,208	4,243	4,149	4,299	4,353	4,451	4,391	4,397	4,474	4,566
West Position	25	(1)	0	(837)	(840)	(721)	(811)	(839)	(691)	(909)
West Reserve Margin	13%	12%	12%	(10%)	(10%)	(6%)	(9%)	(9%)	(5%)	(10%)
System										
Total Resources	13,143	12,815	12,433	11,437	11,515	11,543	11,662	11,651	11,648	11,456
Obligation	11,430	11,628	11,687	11,996	12,284	12,504	12,701	12,980	13,151	13,441
Reserves	1,131	1,187	1,243	1,377	1,407	1,437	1,459	1,494	1,513	1,543
Obligation + Reserves	12,561	12,815	12,931	13,373	13,692	13,940	14,160	14,474	14,664	14,984
System Position	583	(0)	(498)	(1,936)	(2,176)	(2,397)	(2,498)	(2,823)	(3,016)	(3,528)
Reserve Margin	17%	12%	8%	(4%)	(6%)	(7%)	(8%)	(10%)	(11%)	(14%)

Table 5.19 – System Capacity Loads and Resources (15% Target Reserve Margin)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
System										
Total Resources	13,143	12,815	12,433	11,437	11,515	11,543	11,662	11,651	11,648	11,456
Obligation	11,430	11,628	11,687	11,996	12,284	12,504	12,701	12,980	13,151	13,441
Reserves	1,395	1,464	1,535	1,703	1,740	1,776	1,805	1,848	1,872	1,910
Obligation + Reserves	12,824	13,092	13,222	13,698	14,024	14,280	14,505	14,828	15,023	15,351
System Position	319	(277)	(789)	(2,261)	(2,509)	(2,737)	(2,843)	(3,177)	(3,375)	(3,895)
Reserve Margin	18%	13%	8%	(4%)	(5%)	(7%)	(7%)	(9%)	(11%)	(14%)

Figure 5.3 – System Capacity Position Trend

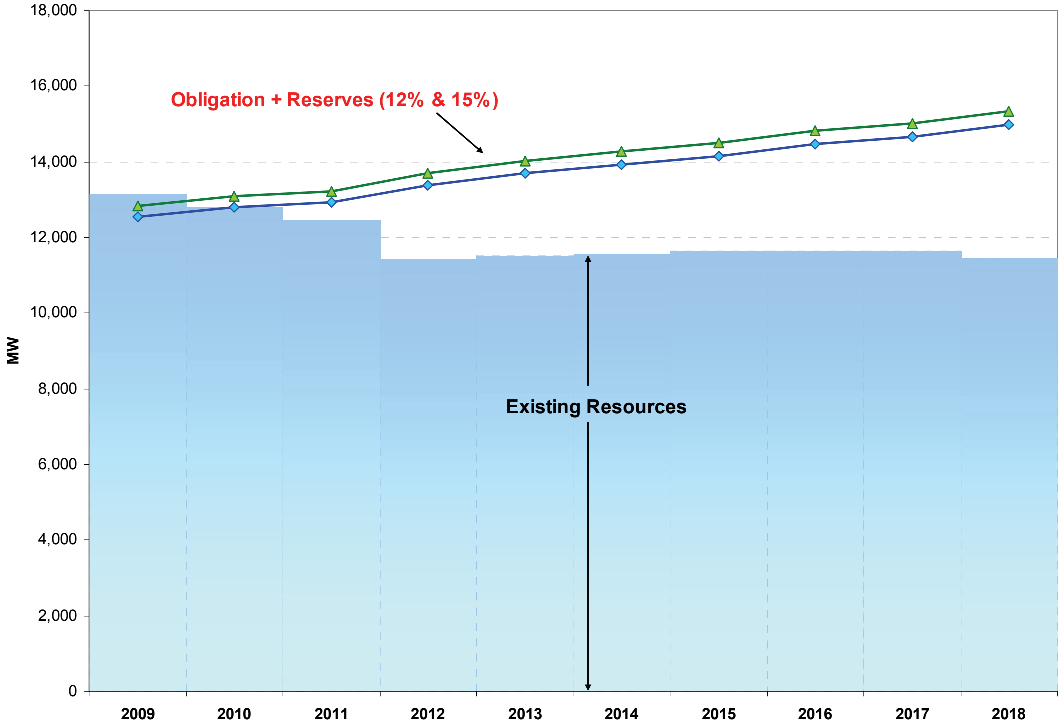


Figure 5.4 – West Capacity Position Trend

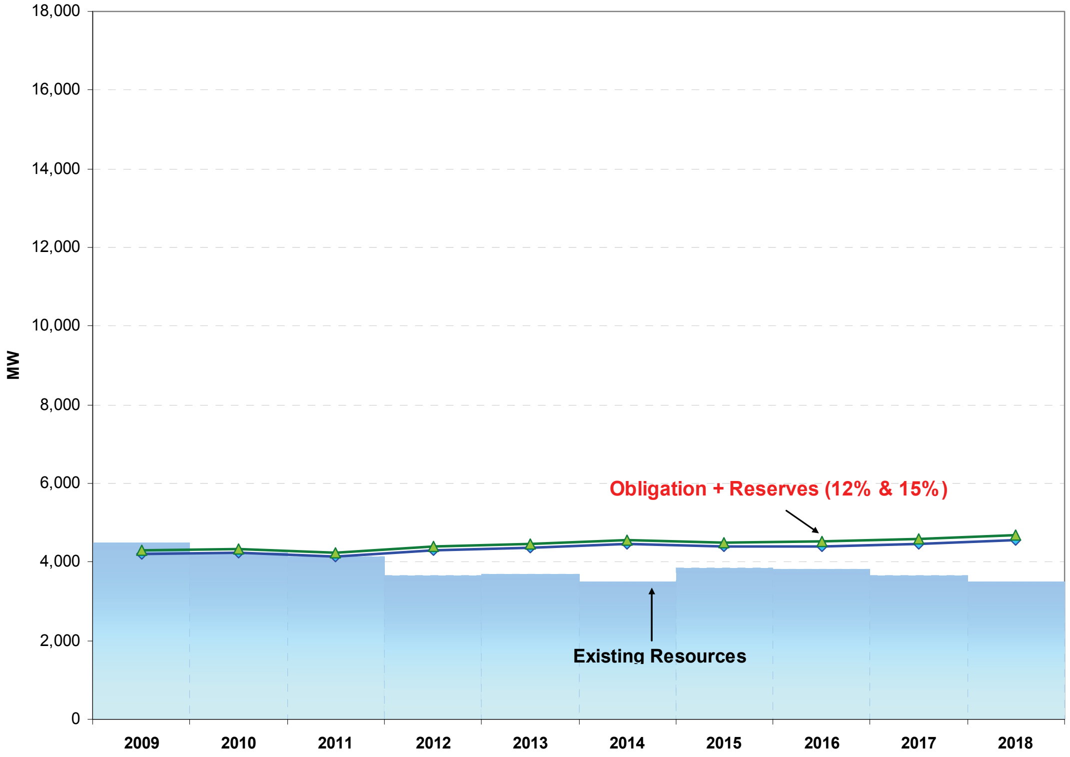
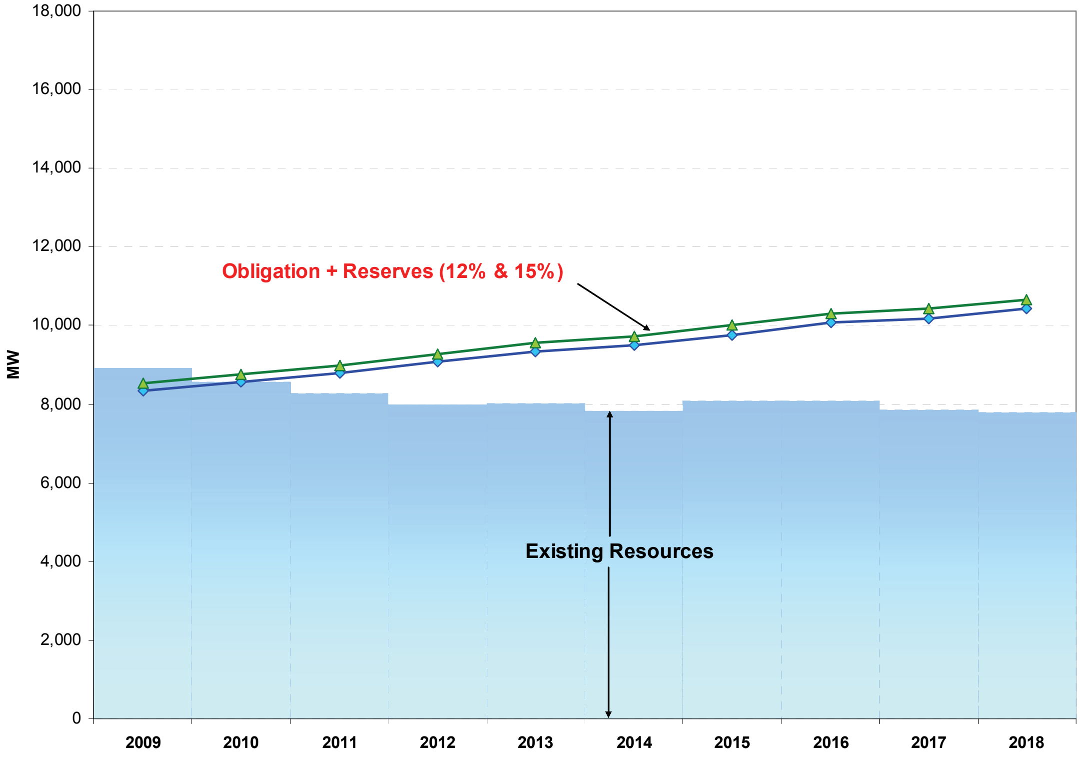


Figure 5.5 – East Capacity Position Trend



Energy Balance Determination

Methodology

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

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

The average obligation is computed using the following formula:

Obligation *= Load + Sales*

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

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

Energy Balance Results

Figures 5.6 through 5.8 show the energy balances for the system, west control area, and east control area, respectively. They indicate the energy balance on a monthly average basis across all hours, and also indicate the average annual energy position. The cross-over point, where the system starts to become energy deficient on a summer hour basis, is 2012, absent any economic considerations.

Figure 5.6 – System Average Monthly and Annual Energy Balances

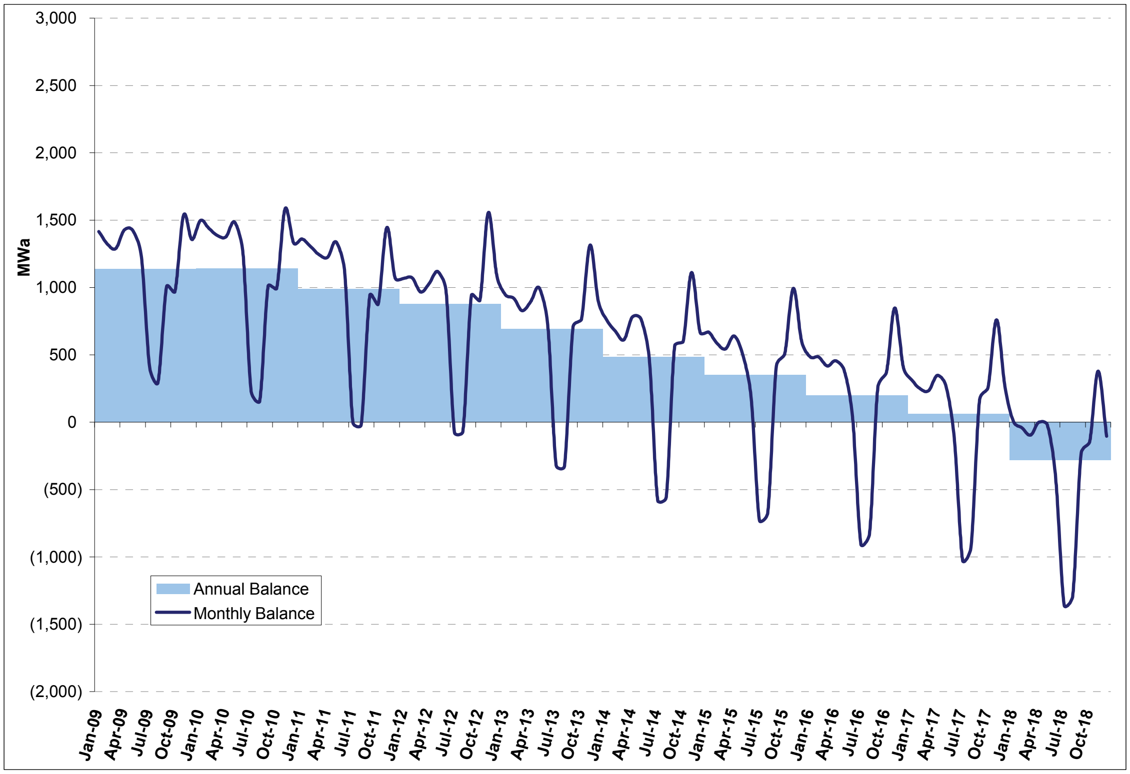


Figure 5.7 – West Average Monthly and Annual Energy Balances

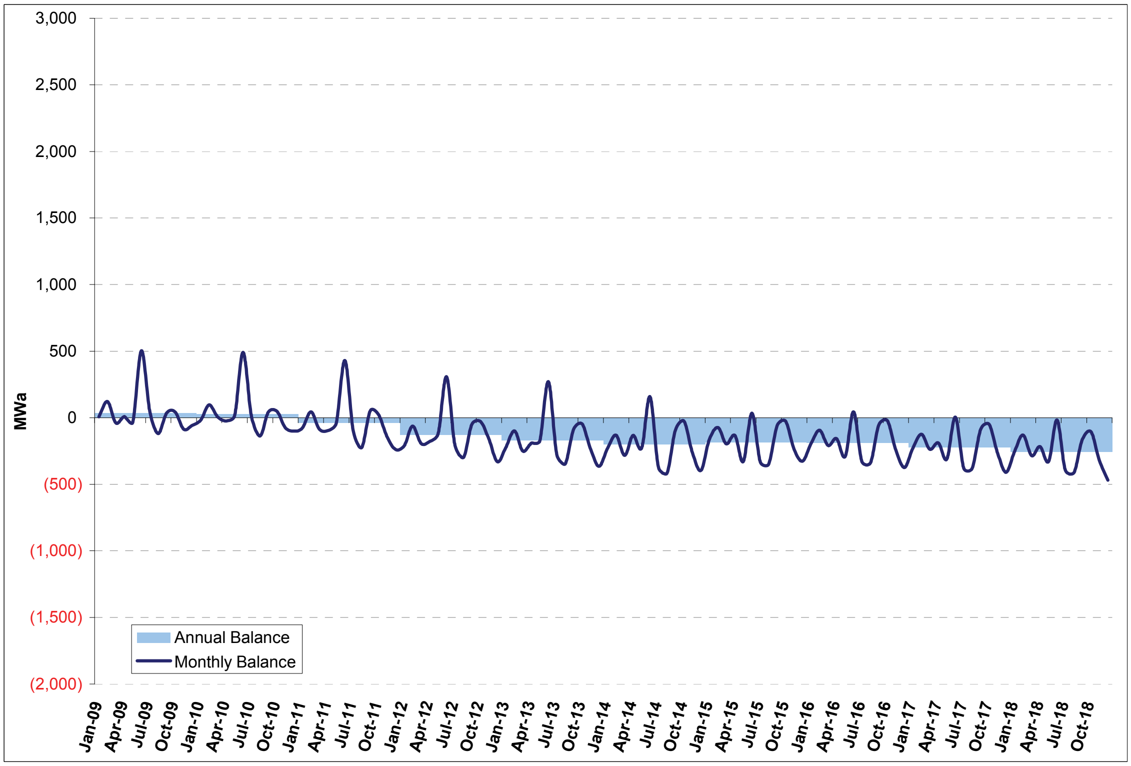
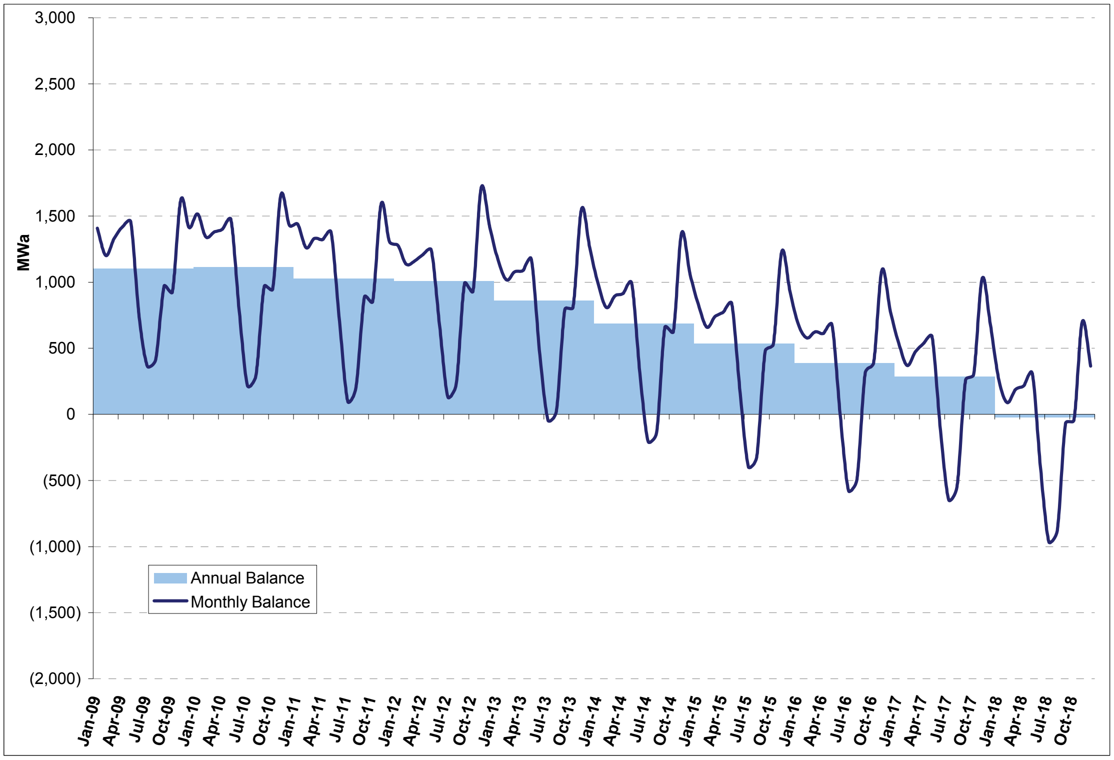


Figure 5.8 – East Average Monthly and Annual Energy Balances



Load and Resource Balance Conclusions

The Company projects a summer peak resource deficit for the PacifiCorp system beginning in 2010 to 2011, depending on the planning reserve margin assumed. The PacifiCorp deficits prior to 2012 will be met by additional renewables, demand-side programs, market purchases, and coal plant turbine upgrades. The Company will consider other options during this time frame if they are cost-effective and provide other system benefits. Then, beginning 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity deficit. The capacity balance at a 12 percent planning reserve margin indicates the start of a deficit beginning in 2011—the system is short by 498 MW. For 2012, the capacity deficit increases to 1,936 MW. By 2018, the deficit increases to 3,528 MW. The Company becomes deficit with respect to summer energy by 2012.

6. RESOURCE OPTIONS

INTRODUCTION

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

SUPPLY-SIDE RESOURCES

Resource Selection Criteria

The list of supply-side resource options has been modified in relation to previous IRP resource lists to reflect the realities evidenced through permitting, public meeting comments, and studies undertaken to better understand the details of available generation resources. For instance, coal options have been decreased with a greater emphasis on carbon capture and sequestration. Natural gas options have been expanded to include a dry-cooled combined cycle option and separate gas options were developed for Wyoming. Alternative energy resources have been given a greater emphasis. Specifically additional solar generation options and geothermal options have been included in the analysis compared to the previous IRP. Additional solar resources include utility-size (10 MWs or greater) concentrated photovoltaic as well as solar thermal with six hours of thermal storage. Energy storage systems continue to be of interest, and advanced large batteries (1 MW) have been reviewed as well as traditional pumped hydro and compressed air energy storage.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2007 IRP. This resource list was reviewed and modified to reflect public input and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. A number of information sources were used to identify parameters needed to model these resources. Supporting utility-scale resources were a number of engineering studies conducted by PacifiCorp to understand the cost of coal and gas resources in recent years. Additionally, experience with the construction of the 2x1 combined cycle plants at Currant Creek and Lake Side as well as other recent simple-cycle projects at Gadsby and West Valley provided PacifiCorp with a detailed understanding of the cost of new power generating facilities. Preparation of benchmark submittals for PacifiCorp's recent generation RFPs were also used to update actual project experience, while government studies were relied upon for characterizing future carbon capture costs.

Extensive new studies on the cost of the coal-fired options were not prepared in keeping with the reduced emphasis on these resources for new near-term generation.

The results of these estimating efforts were compared with other cost databases, such as the one supporting the IPM® market model developed by ICF International, which the Company now uses for national emissions policy impact analysis among other uses. The IPM® cost estimates were used when cost agreement was close.

The WorleyParsons Group was contracted to conduct a high-level renewable generation study specifically for solar, biomass and geothermal resources. The geothermal cost was adjusted to be consistent with estimated project costs for a third unit expansion at Blundell.

Wind costs are based on actual project experience in both the northwest and Wyoming, as well as current projections. Wind costs have been subject to increasing prices due to a lack of supply.[28] Nuclear costs are reflective of recent cost estimates associated with preliminary development activities as well as published estimates of new projects. Hydrokinetic, or wave power, has been added based on proposed projects in the Northwest. Other generation options, such as energy storage and fuel cells, were adopted from PacifiCorp's previous IRP. In some cases costs from the previous IRP were updated using cost increases for other studied resources.

New to PacifiCorp's IRP process is the addition of a variety of small-scale generation resources, consisting of distributed standby generators (DSG), combined heat and power (CHP), and onsite solar supply-side resource options. Together these small resources are referred to as distributed generation. Quantec LLC (now called the Cadmus Group, Inc.) originally provided the distributed generation costs and attributes as part of the DSM potential study conducted for PacifiCorp in 2007.[29] The DSM potential report identified the economic potential for distributed generation resources by state.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many of the proposed generation options is high. Various factors contribute to this uncertainty. Recent experience with lump-sum contracting indicates a greater risk premium is being used by bidders for the traditional turn-key contracts preferred by PacifiCorp for major projects. Shortage of skilled labor and volatile commodity prices are a large part of the increase in project costs for lump-sum contracting. For example, Figure 6.1 shows the trend in North American and world carbon steel prices for selected commodity products. This trend is expected to continue, although the economic slowdown could increase the competitiveness of future proposals as supply and demand reach a better balance.

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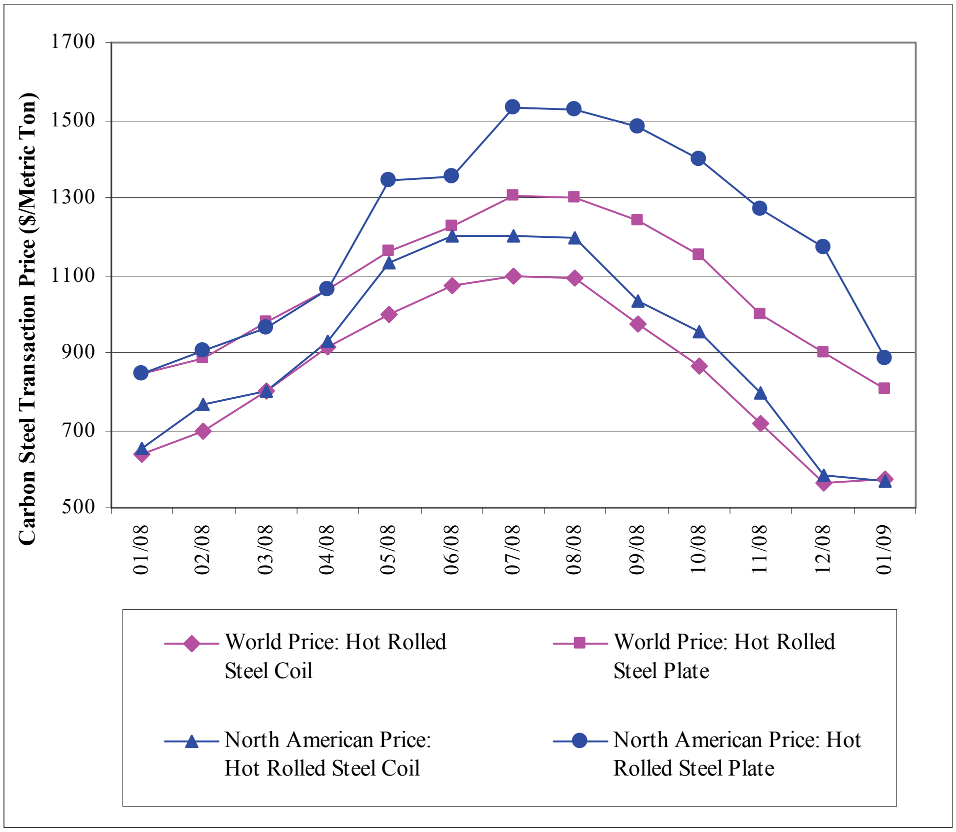
[28] For example, in April 2008, General Electric announced a wind turbine backlog worth $12 billion (CNet News.com, April 13, 2008). In 2008, Siemens Power Generation also announced a four-year backlog in turbine orders. For a review of turbine market trends, see, U.S. Department of Energy, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007 (May 2008).

[29] Quantec LLC, Assessment of Long-Term, System Wide Potential for Demand-Side and Other Supplemental Resources, July 2007.

Figure 6.1 – North American and World Carbon Steel Price Trends



Projects in high demand, such as wind turbines, have seen cost increases as much as 40 percent since the 2007 IRP was developed due to tight turbine supplies. The wind capital costs in the supply-side table were escalated at 5 percent for the years 2009 to 2011 to reflect a continuation of near-term real cost escalation as the backlog of turbine orders is reduced, then return to the nominal inflation rate of about 2 percent thereafter. Note that subsequent to completion of its 2008 IRP portfolio analysis in late 2008 and early 2009, the Company has witnessed price declines for wind turbines and other power plant equipment. These cost declines were not incorporated in portfolio cost estimates. Long-term resource pricing remains challenging to forecast.

Technologies, such as IGCC and some proposed renewable concepts like solar, have a greater uncertainty because only a few demonstration units have been built and operated. There is a potential for future relative cost decreases for these technologies. As these technologies mature and more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal and conventional natural gas-fired plants.

The supply-side resource options tables below do not consider the potential for such savings since the benefits are not expected to be realized until the next generation of new plants are built and operated for a period of time. Any such benefits are not expected to be available until after 2020, and future IRPs will be able to incorporate the benefit of such future cost reductions. A range of estimated capital costs is displayed in the supply-side resource tables. The capital cost range was created by adjusting the base-line estimates by 5 percent on the low end and 20 percent on the high end.

Introduction of many new distributed generation technologies designed to fill the needs of niche markets has helped spur reductions in capital and operating costs. In the DSM potential report, Quantec LLC provided installed cost reduction percentages reflecting these cost trends. Table 6.1 shows the percentage cost reductions by technology type. PacifiCorp applied these cost reductions to the resources included in the IRP models.

Table 6.1 – Distributed Generation Installed Cost Reduction

Technology	Installed Cost Reduction (%/year)
Reciprocating Engine	1%
Microturbine	3%
Fuel Cell	5%
Gas Turbine	1%
Anaerobic Digesters	3%
Industrial Biomass	0.5%

Resource Options and Attributes

Tables 6.2 and 6.3 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 6.4 through 6.7 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2008 dollars. The resource costs are presented for both the \$8 and \$45 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs.

As mentioned above, the attributes were mainly derived from PacifiCorp's recent cost studies and project experience with certain technologies adjusted to be more in line with the IPM database for ICF International. These options are included in PacifiCorp's IRP models but some duplicate gas technologies, such as the CCCT F 1x1 that were not selected in prior IRP's, were turned off to improve the System Optimizer model performance. Cost and performance values reflect analysis concluded by September 2008. Additional explanatory notes for the tables are as follows:

- Capital costs are intended to be all-inclusive, and account for Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Tables 6.2 and 6.3 reflect mid-2008 current dollars, and do not include escalation from the current year to the year of commercial operation.
- Wind sites are modeled with differing peak load carrying capability levels and capacity factors. These levels are reported for each wind site in the Wind Capacity Planning Contribution section of Appendix F.
- Certain resource names are listed as acronyms. These include:
  PC – pulverized coal
  IGCC – integrated gasification combined cycle

SCCT – simple cycle combustion turbine
CCCT – combined cycle combustion turbine
CHP – combined heat and power (cogeneration)
CCS – carbon capture and sequestration
REG – recovered energy generation

- PacifiCorp's October 2008 forward price curves were used to calculate the levelized fuel costs reported in Tables 6.4 through 6.6.
- The costs presented do not include any investment tax credits with the exception of utility solar projects that qualify for the 30% federal tax credit under the Emergency Economic Stabilization Act of 2008 signed into law in October 2008. The utility solar projects do not qualify for the federal production tax credit.
- Gas backup for solar with a heat rate of 11,750 Btu/kWh is less efficient than for a stand-alone CCCT.
- For the nuclear option, costs do not include fuel disposal but do include the cost of transmission.
- The capital cost columns in Tables 6.2 and 6.3 reports the low and high capital cost estimates. The average capital cost is reported in Tables 6.4 through 6.7.
- The capacity shown for retrofitting CCS on existing pulverized coal plants is a net change from current capacity (proportional to 500 MW). The heat rate is the total net plant heat rate based on a nominal 10,000 Btu/kWh without CCS.
- The wind resources entered in the table are representative resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources would be performed as part of the acquisition process. Also, the listed capacity factors are not intended to characterize wind quality for a particular region.
- Heat rates are not adjusted for degradation over time. PacifiCorp assumes that efficiency improvements will offset degradation impacts.

Table 6.2 – East Side Supply-Side Resource Options

	Location / Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation Location	Earliest In-Service Date Mid-Year	Average Capacity (MW)	Design Plant Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Low Estimate Capital Cost ($/kW)	High Estimate Capital Cost ($/kW)	Var. O&M ($/MWh)	Fixed O&M ($/kw-yr)	SO2 lbs/MMBTU	NOx lbs/MMBTU	Hg lbs/Tbtu	CO2 lbs/MMBTU
East Side Options (4500')															
Coal															
Utah PC without Carbon Capture & Sequestration	Utah	2020	600	40	9,106	5%	4%	2,788	3,521	$ 0.96	$ 38.80	0.100	0.070	0.40	205.35
Utah PC with Carbon Capture & Sequestration	Utah	2025	526	40	13,087	5%	5%	5,040	6,367	$ 6.71	$ 66.07	0.050	0.020	0.20	20.54
Utah IGCC with Carbon Capture & Sequestration	Utah	2025	466	40	10,823	7%	8%	4,880	6,164	$ 11.28	$ 53.24	0.050	0.011	0.04	20.54
Wyoming PC without Carbon Capture & Sequestration	Wyoming	2020	790	40	9,214	5%	4%	3,156	3,987	$ 1.27	$ 36.00	0.100	0.070	0.60	205.35
Wyoming PC with Carbon Capture & Sequestration	Wyoming	2025	692	40	13,242	5%	5%	5,707	7,209	$ 7.26	$ 61.37	0.050	0.020	0.30	20.54
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	2025	456	40	11,047	7%	8%	5,525	6,979	$ 13.52	$ 58.00	0.050	0.011	0.06	20.54
Existing PC with Carbon Capture & Sequestration (500 MW)	UT / WY	2025	(139)	20	14,372	5%	5%	1,253	1,583	$ 6.71	$ 66.07	0.050	0.011	0.30	20.54
Natural Gas															
Utility Cogeneration	Utah	2011	10	25	4,974	10%	8%	4,822	6,091	$ 23.29	$ 1.86	-	-	0.26	118.00
Fuel Cell - Large	Utah	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.40	0.001	-	0.26	118.00
SCCT Aero	Utah	2012	118	30	9,773	4%	3%	1,070	1,351	$ 5.63	$ 9.95	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Utah	2012	174	30	9,402	4%	3%	999	1,262	$ 2.71	$ 4.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Utah	2012	261	30	9,402	4%	3%	999	1,262	$ 2.71	$ 4.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Wyoming	2012	241	30	9,402	4%	3%	1,083	1,368	$ 2.94	$ 4.39	0.001	0.011	0.26	118.00
Internal Combustion Engines	Utah	2009	153	30	8,500	5%	1%	1,258	1,589	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Utah	2012	302	35	11,659	4%	3%	710	897	$ 4.47	$ 3.74	0.001	0.050	0.26	118.00
SCCT Frame (2 Frame "F")	Wyoming	2012	275	35	11,659	4%	3%	770	972	$ 4.85	$ 4.05	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Utah	2013	222	40	7,302	4%	3%	1,298	1,640	$ 2.94	$ 12.79	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Utah	2013	50	40	8,869	4%	3%	530	669	$ 0.39	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Utah	2013	506	40	7,098	4%	3%	1,182	1,493	$ 2.94	$ 7.77	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Utah	2013	64	40	8,557	4%	3%	596	753	$ 0.39	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Dry "F" 2x1)	Utah	2017	438	40	7,368	4%	3%	1,212	1,530	$ 3.35	$ 9.69	0.001	0.011	0.26	118.00
CCCT Duct Firing (Dry "F" 2x1)	Utah	2017	98	40	8,950	4%	3%	611	772	$ 0.11	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Utah	2013	333	40	6,884	4%	3%	1,227	1,550	$ 4.56	$ 6.75	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Utah	2013	72	40	9,021	4%	3%	520	656	$ 0.36	$ 1.63	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Utah	2018	400	40	6,760	4%	3%	1,355	1,712	$ 4.56	$ 6.75	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Utah	2018	75	40	9,021	4%	3%	665	840	$ 0.36	$ 1.63	0.001	0.011	0.26	118.00
Other - Renewables															
East (Wyoming) Wind (35% CF)	Wyoming	2010	100	25	n/a	n/a	n/a	2,215	2,954	-	$ 31.43	-	-	-	-
East Side Geothermal (Blundell)	Utah	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
East Side Geothermal (Green Field)	Utah	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
Battery Storage	Utah	2014	5	30	12,000	2%	5%	1,980	2,501	$ 10.00	$ 1.00	0.100	0.400	3.00	205.35
Pumped Storage	Nevada	2018	350	50	13,000	5%	5%	1,684	2,127	$ 4.30	$ 4.30	0.100	0.400	3.00	205.35
Compressed Air Energy Storage (CAES)	Wyoming	2015	350	30	11,980	4%	3%	1,483	1,873	$ 5.50	$ 3.80	0.001	0.011	0.26	118.00
Recovered Energy Generation (CHP)	UT / WY	2011	12	30	-	8%	8%	5,500	5,500	-	$ 91.92	-	-	-	-
Nuclear	Utah	2025	1,600	40	10,710	7%	8%	5,188	6,553	$ 1.63	$ 146.70	-	-	-	-
Solar Concentrating (PV) - 30% CF	Utah	2015	10	20	n/a	n/a	n/a	6,194	7,824	-	$ 180.00	-	-	-	-
Solar Concentrating (natural gas backup) - 25% solar	Utah	2015	250	20	n/a	n/a	n/a	3,943	4,980	-	$ 195.60	-	-	-	-
Solar Concentrating (thermal storage) - 30% solar	Utah	2012	250	30	n/a	n/a	n/a	4,418	5,580	-	$ 139.50	-	-	-	-

Table 6.3 – West Side Supply-Side Resource Options

	Location / Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation Location	Earliest In-Service Date Mid-Year	Average Capacity (MW)	Design Plant Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Low Estimate Capital Cost ($/kW)	High Estimate Capital Cost ($/kW)	Var. O&M ($/MWh)	Fixed O&M ($/kw-yr)	SO2 lbs/MMBTU	NOx lbs/MMBTU	Hg lbs/Tbtu	CO2 lbs/MMBTU
West Side Options (1500')															
Natural Gas															
Fuel Cell - Large	Northwest	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.40	0.001	-	0.26	118.00
SCCT Aero	Northwest	2012	130	30	9,773	4%	3%	972	1,228	$ 5.12	$ 9.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Northwest	2012	287	30	9,402	4%	3%	908	1,147	$ 2.46	$ 3.68	0.001	0.011	0.26	118.00
Internal Combustion Engines	Northwest	2012	168	30	8,500	5%	1%	1,143	1,444	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Northwest	2012	338	35	11,659	4%	3%	645	815	$ 4.07	$ 3.40	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Northwest	2013	244	40	7,302	4%	3%	1,180	1,491	$ 2.67	$ 11.62	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2013	55	40	8,869	4%	3%	482	608	$ 0.36	$ 1.45	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Northwest	2013	557	40	7,098	4%	3%	1,074	1,357	$ 2.67	$ 7.07	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2013	70	40	8,557	4%	3%	542	685	$ 0.36	$ 1.45	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Northwest	2013	367	40	6,884	4%	3%	1,116	1,409	$ 4.14	$ 6.13	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2013	80	40	9,021	4%	3%	472	597	$ 0.33	$ 1.48	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Northwest	2018	440	40	6,760	4%	3%	1,232	1,556	$ 4.14	$ 6.13	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Northwest	2018	83	40	9,021	4%	3%	605	764	$ 0.33	$ 1.48	0.001	0.011	0.26	118.00
Other - Renewables															
West Wind	Northwest	2010	50	25	n/a	n/a	n/a	2,350	3,134	-	$ 31.43	-	-	-	-
Biomass	Northwest	2015	50	30	10,979	5%	4%	3,179	4,016	$ 0.96	$ 38.80	0.100	0.350	0.40	205.39
West Side Geothermal (Green Field)	Northwest	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
Compressed Air Energy Storage (CAES)	Northwest	2015	385	30	11,980	4%	3%	1,483	1,873	$ 5.00	$ 3.45	0.001	0.011	0.26	118.00
Hydrokinetic (Wave) - 21% CF	Northwest	2015	100	20	n/a	n/a	n/a	5,700	7,200	-	$ 180.00	-	-	-	-
West Side Options (Sea Level)															
Natural Gas															
Fuel Cell - Large	Northwest	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.40	0.001	-	0.26	118.00
SCCT Aero	Northwest	2012	136	30	9,773	2%	3%	924	1,167	$ 4.87	$ 8.59	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Northwest	2012	302	30	9,402	4%	3%	863	1,090	$ 2.35	$ 3.49	0.001	0.011	0.26	118.00
Internal Combustion Engines	Northwest	2012	177	30	8,500	4%	1%	1,086	1,372	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Northwest	2012	356	35	11,659	5%	3%	613	774	$ 3.87	$ 3.23	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Northwest	2013	257	40	7,302	4%	3%	1,121	1,416	$ 2.55	$ 11.07	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2013	58	40	8,869	4%	3%	458	578	$ 0.34	$ 1.38	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Northwest	2013	586	40	7,098	4%	3%	1,020	1,289	$ 2.55	$ 6.73	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2013	74	40	8,557	4%	3%	515	650	$ 0.34	$ 1.38	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Northwest	2013	386	40	6,884	4%	3%	1,060	1,339	$ 3.94	$ 5.84	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2010	84	40	9,021	4%	3%	449	567	$ 0.31	$ 1.41	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Northwest	2018	463	40	6,760	4%	3%	1,170	1,479	$ 3.94	$ 5.84	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Northwest	2018	87	40	9,021	4%	3%	574	725	$ 0.31	$ 1.41	0.001	0.011	0.26	119.00

Table 6.4 – Total Resource Cost for East Side Supply-Side Resource Options, \$8 CO_2 Tax

	Capital Cost $/kW			**Fixed Cost**				**Convert to Mills**				**Variable Costs** mills/kWh				**Total Resource Cost**
				Fixed O&M $/kW-Yr						Levelized Fuel						
Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	**(Mills/kWh)**
East Side Options (4500')																
Coal																
Utah PC without Carbon Capture & Sequestration	2,934	8.40%	$ 246.57	$ 38.80	$ 6.00	$ 44.80	$ 291.37	91%	36.39	216.23	19.69	$ 0.96	-	-	5.10	62.14
Utah PC with Carbon Capture & Sequestration	5,306	8.25%	$ 437.60	$ 66.07	$ 6.00	$ 72.07	$ 509.68	90%	64.65	216.23	28.30	$ 6.71	-	-	0.78	100.43
Utah IGCC with Carbon Capture & Sequestration	5,136	8.01%	$ 411.32	$ 53.24	$ 6.00	$ 59.24	$ 470.56	85%	63.20	216.23	23.40	$ 11.28	-	-	0.64	98.52
Wyoming PC without Carbon Capture & Sequestration	3,322	8.40%	$ 279.19	$ 36.00	$ 6.00	$ 42.00	$ 321.19	91%	40.12	238.45	21.97	$ 1.27	-	-	5.16	68.52
Wyoming PC with Carbon Capture & Sequestration	6,007	8.25%	$ 495.50	$ 61.37	$ 6.00	$ 67.37	$ 562.86	90%	71.39	238.45	31.58	$ 7.26	-	-	0.79	111.02
Wyoming IGCC with Carbon Capture & Sequestration	5,816	8.01%	$ 465.74	$ 58.00	$ 6.00	$ 64.00	$ 529.74	85%	71.14	238.45	26.34	$ 13.52	-	-	0.66	111.66
Existing PC with Carbon Capture & Sequestration (500 MW)	1,319	10.71%	$ 141.23	$ 66.07	$ 6.00	$ 72.07	$ 213.30	90%	27.05	238.45	34.27	$ 6.71	-	-	0.86	68.89
Natural Gas																
Utility Cogeneration	5,076	10.12%	$ 513.46	$ 1.86	$ 0.50	$ 2.36	$ 515.82	82%	71.81	699.22	34.78	$ 23.29	4.17	-	1.58	135.63
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	699.22	50.78	$ 0.03	6.09	-	2.30	79.06
SCCT Aero	1,126	9.08%	$ 102.21	$ 9.95	$ 0.50	$ 10.45	$ 112.66	21%	61.24	699.22	68.34	$ 5.63	8.20	-	3.10	146.51
Intercooled Aero SCCT (Utah, 174MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	699.22	65.74	$ 2.71	7.89	-	2.98	133.68
Intercooled Aero SCCT (Utah, 261MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	699.22	65.74	$ 2.71	7.89	-	2.98	133.68
Intercooled Aero SCCT (Wyoming, 241MW)	1,140	9.08%	$ 103.50	$ 4.39	$ 0.50	$ 4.89	$ 108.38	21%	58.92	699.22	65.74	$ 2.94	6.83	-	2.98	137.41
Internal Combustion Engines	1,324	9.08%	$ 120.18	$ 12.80	$ 0.50	$ 13.30	$ 133.48	94%	16.21	699.22	59.43	$ 5.20	7.13	-	2.70	90.67
SCCT Frame (2 Frame "F")	747	8.62%	$ 64.39	$ 3.74	$ 0.50	$ 4.24	$ 68.62	21%	37.30	699.22	81.53	$ 4.47	9.78	-	3.70	136.78
SCCT Frame (2 Frame "F")	810	8.62%	$ 69.82	$ 4.05	$ 0.50	$ 4.55	$ 74.37	21%	40.43	699.22	81.53	$ 4.85	8.47	-	3.70	138.97
CCCT (Wet "F" 1x1)	1,366	8.59%	$ 117.32	$ 12.79	$ 0.50	$ 13.29	$ 130.61	56%	26.62	699.22	51.06	$ 2.94	6.13	-	2.32	89.07
CCCT Duct Firing (Wet "F" 1x1)	558	8.59%	$ 47.88	$ 1.60	$ 0.50	$ 2.10	$ 49.98	16%	35.66	699.22	62.01	$ 0.39	7.44	-	2.81	108.32
CCCT (Wet "F" 2x1)	1,244	8.59%	$ 106.79	$ 7.77	$ 0.50	$ 8.27	$ 115.06	56%	23.46	699.22	49.63	$ 2.94	5.96	-	2.25	84.24
CCCT Duct Firing (Wet "F" 2x1)	628	8.59%	$ 53.88	$ 1.60	$ 0.50	$ 2.10	$ 55.98	16%	39.94	699.22	59.84	$ 0.39	7.18	-	2.71	110.06
CCCT (Dry "F" 2x1)	1,275	8.59%	$ 109.50	$ 9.69	$ 0.50	$ 10.19	$ 119.70	56%	24.40	699.22	51.52	$ 3.35	6.18	-	2.34	87.79
CCCT Duct Firing (Dry "F" 2x1)	644	8.59%	$ 55.25	$ 1.60	$ 0.50	$ 2.10	$ 57.35	16%	40.91	699.22	62.58	$ 0.11	7.51	-	2.84	113.95
CCCT (Wet "G" 1x1)	1,292	8.59%	$ 110.93	$ 6.75	$ 0.50	$ 7.25	$ 118.18	56%	24.09	699.22	48.14	$ 4.56	5.78	-	2.18	84.74
CCCT Duct Firing (Wet "G" 1x1)	547	8.59%	$ 46.96	$ 1.63	$ 0.50	$ 2.13	$ 49.09	16%	35.03	699.22	63.08	$ 0.36	7.57	-	2.86	108.89
CCCT Advanced (Wet)	1,427	8.59%	$ 122.49	$ 6.75	$ 0.50	$ 7.25	$ 129.74	56%	26.45	699.22	47.27	$ 4.56	5.67	-	2.14	86.08
CCCT Advanced Duct Firing (Wet)	700	8.59%	$ 60.10	$ 1.63	$ 0.50	$ 2.13	$ 62.24	16%	44.40	699.22	63.08	$ 0.36	7.57	-	2.86	118.27
Other - Renewables																
East (Wyoming) Wind (35% CF)	2,566	8.72%	$ 223.58	$ 31.43	$ 0.50	$ 31.93	$ 255.51	35%	83.34	-	-	-	11.75	(20.70)	-	74.38
East Side Geothermal (Blundell)	6,087	7.42%	$ 451.64	$ 110.85	$ 0.50	$ 111.35	$ 562.99	90%	71.41	-	-	$ 5.94		(20.70)	-	56.64
East Side Geothermal (Green Field)	7,608	7.42%	$ 564.55	$ 221.70	$ 0.50	$ 222.20	$ 786.74	90%	99.79	-	-	$ 11.88		(20.70)	-	90.97
Battery Storage	2,084	8.29%	$ 172.77	$ 1.00	$ 0.50	$ 1.50	$ 174.27	21%	94.73	699.22	83.91	$ 10.00	10.07	-	6.73	205.43
Pumped Storage	1,773	8.19%	$ 145.14	$ 4.30	$ 1.35	$ 5.65	$ 150.79	20%	86.06	699.22	90.90	$ 4.30	10.91	-	7.29	199.46
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.80	$ 1.35	$ 5.15	$ 134.56	47%	32.89	699.22	83.77	$ 5.50	8.70	-	3.80	134.66
Recovered Energy Generation (CHP)	5,500	9.39%	$ 516.67	$ 91.92	-	$ 91.92	$ 608.59	84%	82.71	-	-	-	-	-	-	82.71
Nuclear	5,461	8.30%	$ 453.26	$ 146.70	$ 6.00	$ 152.70	$ 605.95	85%	81.38	113.98	12.21	$ 1.63	-	-	-	95.22
Solar Concentrating (PV) - 30% CF	6,520	6.48%	$ 422.43	$ 180.00	$ 6.00	$ 186.00	$ 608.43	30%	231.52	-	-	-	-	(1.59)	-	229.93
Solar Concentrating (natural gas backup) - 25% solar	4,150	6.48%	$ 268.88	$ 195.60	$ 6.00	$ 201.60	$ 470.48	33%	162.75	699.22	18.96	-	2.28	(1.59)	0.86	183.26
Solar Concentrating (thermal storage) - 30% solar	4,650	5.46%	$ 253.80	$ 139.50	$ 6.00	$ 145.50	$ 399.30	30%	151.94	-	-	-	-	(1.59)	-	150.35

Table 6.5 – Total Resource Cost for West Side Supply-Side Resource Options, $8 CO_2 Tax

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs mills/kWh				Total Resource Cost
				Fixed O&M $/kW-Yr						Levelized Fuel						
Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	(Mills/kWh)
West Side Options (1500')																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	814.00	59.11	$ 0.03	5.33	-	2.30	86.63
SCCT Aero	1,024	9.08%	$ 92.92	$ 9.04	$ 0.50	$ 9.54	$ 102.46	21%	55.70	814.00	79.55	$ 5.12	7.17	-	3.10	150.64
Intercooled Aero SCCT	956	9.08%	$ 86.77	$ 3.68	$ 0.50	$ 4.18	$ 90.95	21%	49.44	814.00	76.53	$ 2.46	6.90	-	2.98	138.32
Internal Combustion Engines	1,204	9.08%	$ 109.25	$ 12.80	$ 0.50	$ 13.30	$ 122.55	94%	14.88	814.00	69.19	$ 5.20	6.24	-	2.70	98.20
SCCT Frame (2 Frame "F")	679	8.62%	$ 58.53	$ 3.40	$ 0.50	$ 3.90	$ 62.43	21%	33.94	814.00	94.91	$ 4.07	8.56	-	3.70	145.16
CCCT (Wet "F" 1x1)	1,242	8.59%	$ 106.66	$ 11.62	$ 0.50	$ 12.12	$ 118.78	56%	24.21	814.00	59.44	$ 2.67	5.36	-	2.32	94.00
CCCT Duct Firing (Wet "F" 1x1)	507	8.59%	$ 43.53	$ 1.45	$ 0.50	$ 1.95	$ 45.48	16%	32.45	814.00	72.19	$ 0.36	6.51	-	2.81	114.32
CCCT (Wet "F" 2x1)	1,131	8.59%	$ 97.08	$ 7.07	$ 0.50	$ 7.57	$ 104.65	56%	21.33	814.00	57.78	$ 2.67	5.21	-	2.25	89.25
CCCT Duct Firing (Wet "F" 2x1)	570	8.59%	$ 48.98	$ 1.45	$ 0.50	$ 1.95	$ 50.93	16%	36.34	814.00	69.66	$ 0.36	6.28	-	2.71	115.35
CCCT (Wet "G" 1x1)	1,175	8.59%	$ 100.85	$ 6.13	$ 0.50	$ 6.63	$ 107.48	56%	21.91	814.00	56.04	$ 4.14	5.05	-	2.18	89.32
CCCT Duct Firing (Wet "G" 1x1)	497	8.59%	$ 42.69	$ 1.48	$ 0.50	$ 1.98	$ 44.68	16%	31.88	814.00	73.43	$ 0.33	6.62	-	2.86	115.12
CCCT Advanced (Wet)	1,297	8.59%	$ 111.36	$ 6.13	$ 0.50	$ 6.63	$ 117.99	56%	24.05	814.00	55.02	$ 4.14	4.96	-	2.14	90.32
CCCT Advanced Duct Firing (Wet)	636	8.59%	$ 54.64	$ 1.48	$ 0.50	$ 1.98	$ 56.62	16%	40.40	814.00	73.43	$ 0.33	6.62	-	2.86	123.64
Other - Renewables																
West Wind	2,612	8.72%	$ 227.59	$ 31.43	$ 27.74	$ 59.17	$ 286.76	29%	112.88	-	-	-	11.75	(20.70)	-	103.93
Biomass	3,347	8.10%	$ 271.22	$ 38.80	$ 0.50	$ 39.30	$ 310.52	91%	38.78	590.00	64.78	$ 0.96	-	(20.70)	6.15	89.97
West Side Geothermal (Green Field)	7,609	7.42%	$ 564.62	$ 221.70	$ 0.50	$ 222.20	$ 786.82	90%	99.80	-	-	$ 11.88	-	(20.70)	-	90.98
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.45	$ 1.35	$ 4.80	$ 134.21	47%	32.81	814.00	97.52	$ 5.00	8.79	-	3.80	147.91
Hydrokinetic (Wave) - 21% CF	6,000	9.69%	$ 581.58	$ 180.00	$ 6.00	$ 186.00	$ 767.58	21%	417.25	-	-	-	-	-	-	417.25
West Side Options (Sea Level)																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	814.00	59.11	$ 0.03	5.33	-	2.30	86.63
SCCT Aero	972	9.08%	$ 88.27	$ 8.59	$ 0.50	$ 9.09	$ 97.36	21%	52.93	814.00	79.55	$ 4.87	7.17	-	3.10	147.63
Intercooled Aero SCCT	908	9.08%	$ 82.43	$ 3.49	$ 0.50	$ 3.99	$ 86.43	21%	46.98	814.00	76.53	$ 2.35	6.90	-	2.98	135.74
Internal Combustion Engines	1,143	9.08%	$ 103.79	$ 12.80	$ 0.50	$ 13.30	$ 117.09	94%	14.22	814.00	69.19	$ 5.20	6.24	-	2.70	97.54
SCCT Frame (2 Frame "F")	645	8.62%	$ 55.61	$ 3.23	$ 0.50	$ 3.73	$ 59.34	21%	32.26	814.00	94.91	$ 3.87	8.56	-	3.70	143.29
CCCT (Wet "F" 1x1)	1,180	8.59%	$ 101.32	$ 11.07	$ 0.50	$ 11.57	$ 112.89	56%	23.01	814.00	59.44	$ 2.55	5.36	-	2.32	92.67
CCCT Duct Firing (Wet "F" 1x1)	482	8.59%	$ 41.35	$ 1.38	$ 0.50	$ 1.88	$ 43.23	16%	30.85	814.00	72.19	$ 0.34	6.51	-	2.81	112.70
CCCT (Wet "F" 2x1)	1,074	8.59%	$ 92.23	$ 6.73	$ 0.50	$ 7.23	$ 99.46	56%	20.27	814.00	57.78	$ 2.55	5.21	-	2.25	88.06
CCCT Duct Firing (Wet "F" 2x1)	542	8.59%	$ 46.53	$ 1.38	$ 0.50	$ 1.88	$ 48.42	16%	34.54	814.00	69.66	$ 0.34	6.28	-	2.71	113.53
CCCT (Wet "G" 1x1)	1,116	8.59%	$ 95.81	$ 5.84	$ 0.50	$ 6.34	$ 102.15	56%	20.82	814.00	56.04	$ 3.94	5.05	-	2.18	88.04
CCCT Duct Firing (Wet "G" 1x1)	472	8.59%	$ 40.56	$ 1.41	$ 0.50	$ 1.91	$ 42.47	16%	30.30	814.00	73.43	$ 0.31	6.62	-	2.86	113.53
CCCT Advanced (Wet)	1,232	8.59%	$ 105.79	$ 5.84	$ 0.50	$ 6.34	$ 112.13	56%	22.86	814.00	55.02	$ 3.94	4.96	-	2.14	88.93
CCCT Advanced Duct Firing (Wet)	605	8.59%	$ 51.91	$ 1.41	$ 0.50	$ 1.91	$ 53.82	16%	38.40	814.00	73.43	$ 0.31	6.62	-	2.89	121.65

Table 6.6 – Total Resource Cost for East Side Supply-Side Resource Options, $45 CO_2 Tax

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs mills/kWh				Total Resource Cost
				Fixed O&M $/kW-Yr												
	Total	Payment	Annual Payment				Total Fixed	Capacity Factor	Total Fixed	Levelized Fuel						
Description	Capital Cost	Factor	($/kW-Yr)	O&M	Other	Total	($/kW-Yr)		Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	**(Mills/kWh)**
East Side Options (4500')																
Coal																
Utah PC without Carbon Capture & Sequestration	2,934	8.40%	$ 246.57	$ 38.80	$ 6.00	$ 44.80	$ 291.37	91%	36.39	216.23	19.69	$ 0.96	-	-	28.32	85.36
Utah PC with Carbon Capture & Sequestration	5,306	8.25%	$ 437.60	$ 66.07	$ 6.00	$ 72.07	$ 509.68	90%	64.65	216.23	28.30	$ 6.71	-	-	4.11	103.76
Utah IGCC with Carbon Capture & Sequestration	5,136	8.01%	$ 411.32	$ 53.24	$ 6.00	$ 59.24	$ 470.56	85%	63.20	216.23	23.40	$ 11.28	-	-	3.40	101.28
Wyoming PC without Carbon Capture & Sequestration	3,322	8.40%	$ 279.19	$ 36.00	$ 6.00	$ 42.00	$ 321.19	91%	40.12	238.45	21.97	$ 1.27	-	-	28.66	92.02
Wyoming PC with Carbon Capture & Sequestration	6,007	8.25%	$ 495.50	$ 61.37	$ 6.00	$ 67.37	$ 562.86	90%	71.39	238.45	31.58	$ 7.26	-	-	4.16	114.39
Wyoming IGCC with Carbon Capture & Sequestration	5,816	8.01%	$ 465.74	$ 58.00	$ 6.00	$ 64.00	$ 529.74	85%	71.14	238.45	26.34	$ 13.52	-	-	3.47	114.47
Existing PC with Carbon Capture & Sequestration (500 MW)	1,319	10.71%	$ 141.23	$ 66.07	$ 6.00	$ 72.07	$ 213.30	90%	27.05	238.45	34.27	$ 6.71	-	-	4.51	72.54
Natural Gas																
Utility Cogeneration	5,076	10.12%	$ 513.46	$ 1.86	$ 0.50	$ 2.36	$ 515.82	82%	71.81	722.19	35.92	$ 23.29	4.17	-	8.87	144.06
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	722.19	52.44	$ 0.03	6.09	-	12.95	91.37
SCCT Aero	1,126	9.08%	$ 102.21	$ 9.95	$ 0.50	$ 10.45	$ 112.66	21%	61.24	722.19	70.58	$ 5.63	8.20	-	17.43	163.08
Intercooled Aero SCCT (Utah, 174MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	722.19	67.90	$ 2.71	7.89	-	16.77	149.62
Intercooled Aero SCCT (Utah, 261MW)	1,052	9.08%	$ 95.45	$ 4.04	$ 0.50	$ 4.54	$ 99.99	21%	54.36	722.19	67.90	$ 2.71	7.89	-	16.77	149.62
Intercooled Aero SCCT (Wyoming, 241MW)	1,140	9.08%	$ 103.50	$ 4.39	$ 0.50	$ 4.89	$ 108.38	21%	58.92	722.19	67.90	$ 2.94	6.83	-	16.77	153.36
Internal Combustion Engines	1,324	9.08%	$ 120.18	$ 12.80	$ 0.50	$ 13.30	$ 133.48	94%	16.21	722.19	61.38	$ 5.20	7.13	-	15.16	105.08
SCCT Frame (2 Frame "F")	747	8.62%	$ 64.39	$ 3.74	$ 0.50	$ 4.24	$ 68.62	21%	37.30	722.19	84.20	$ 4.47	9.78	-	20.79	156.55
SCCT Frame (2 Frame "F")	810	8.62%	$ 69.82	$ 4.05	$ 0.50	$ 4.55	$ 74.37	21%	40.43	722.19	84.20	$ 4.85	8.47	-	20.79	158.74
CCCT (Wet "F" 1x1)	1,366	8.59%	$ 117.32	$ 12.79	$ 0.50	$ 13.29	$ 130.61	56%	26.62	722.19	52.73	$ 2.94	6.13	-	13.02	101.45
CCCT Duct Firing (Wet "F" 1x1)	558	8.59%	$ 47.88	$ 1.60	$ 0.50	$ 2.10	$ 49.98	16%	35.66	722.19	64.05	$ 0.39	7.44	-	15.82	123.36
CCCT (Wet "F" 2x1)	1,244	8.59%	$ 106.79	$ 7.77	$ 0.50	$ 8.27	$ 115.06	56%	23.46	722.19	51.26	$ 2.94	5.96	-	12.66	96.27
CCCT Duct Firing (Wet "F" 2x1)	628	8.59%	$ 53.88	$ 1.60	$ 0.50	$ 2.10	$ 55.98	16%	39.94	722.19	61.80	$ 0.39	7.18	-	15.26	124.57
CCCT (Dry "F" 2x1)	1,275	8.59%	$ 109.50	$ 9.69	$ 0.50	$ 10.19	$ 119.70	56%	24.40	722.19	53.21	$ 3.35	6.18	-	13.14	100.28
CCCT Duct Firing (Dry "F" 2x1)	644	8.59%	$ 55.25	$ 1.60	$ 0.50	$ 2.10	$ 57.35	16%	40.91	722.19	64.63	$ 0.11	7.51	-	15.96	129.13
CCCT (Wet "G" 1x1)	1,292	8.59%	$ 110.93	$ 6.75	$ 0.50	$ 7.25	$ 118.18	56%	24.09	722.19	49.72	$ 4.56	5.78	-	12.28	96.42
CCCT Duct Firing (Wet "G" 1x1)	547	8.59%	$ 46.96	$ 1.63	$ 0.50	$ 2.13	$ 49.09	16%	35.03	722.19	65.15	$ 0.36	7.57	-	16.09	124.19
CCCT Advanced (Wet)	1,427	8.59%	$ 122.49	$ 6.75	$ 0.50	$ 7.25	$ 129.74	56%	26.45	722.19	48.82	$ 4.56	5.67	-	12.06	97.55
CCCT Advanced Duct Firing (Wet)	700	8.59%	$ 60.10	$ 1.63	$ 0.50	$ 2.13	$ 62.24	16%	44.40	722.19	65.15	$ 0.36	7.57	-	16.09	133.57
Other Renewables																
East (Wyoming) Wind (35% CF)	2,566	8.72%	$ 223.58	$ 31.43	$ 0.50	$ 31.93	$ 255.51	35%	83.34	-	-	-	11.75	(20.70)	-	74.38
East Side Geothermal (Blundell)	6,087	7.42%	$ 451.64	$ 110.85	$ 0.50	$ 111.35	$ 562.99	90%	71.41	-	-	$ 5.94		(20.70)	-	56.64
East Side Geothermal (Green Field)	7,608	7.42%	$ 564.55	$ 221.70	$ 0.50	$ 222.20	$ 786.74	90%	99.79	-	-	$ 11.88		(20.70)	-	90.97
Battery Storage	2,084	8.29%	$ 172.77	$ 1.00	$ 0.50	$ 1.50	$ 174.27	21%	94.73	722.19	86.66	$ 10.00	10.07	-	37.33	238.79
Pumped Storage	1,773	8.19%	$ 145.14	$ 4.30	$ 1.35	$ 5.65	$ 150.79	20%	86.06	722.19	93.88	$ 4.30	10.91	-	40.44	235.60
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.80	$ 1.35	$ 5.15	$ 134.56	47%	32.89	722.19	86.52	$ 5.50	8.70	-	21.37	154.98
Recovered Energy Generation (CHP)	5,500	9.39%	$ 516.67	$ 91.92	-	$ 91.92	$ 608.59	84%	82.71	-	-	-	-	-	-	82.71
Nuclear	5,461	8.30%	$ 453.26	$ 146.70	$ 6.00	$ 152.70	$ 605.95	85%	81.38	113.98	12.21	$ 1.63	-	-	-	95.22
Solar Concentrating (PV) - 30% CF	6,520	6.48%	$ 422.43	$ 180.00	$ 6.00	$ 186.00	$ 608.43	30%	231.52	-	-	-	-	(1.59)	-	229.93
Solar Concentrating (natural gas backup) - 25% solar	4,150	6.48%	$ 268.88	$ 195.60	$ 6.00	$ 201.60	$ 470.48	33%	162.75	722.19	19.59	-	2.28	(1.59)	4.84	187.86
Solar Concentrating (thermal storage) - 30% solar	4,650	5.46%	$ 253.80	$ 139.50	$ 6.00	$ 145.50	$ 399.30	30%	151.94	-	-	-	-	(1.59)	-	150.35

Table 6.7 – Total Resource Cost for West Side Supply-Side Resource Options, $45 CO_2 Tax

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs				Total
			Annual	Fixed O&M $/kW-Yr								mills/kWh				Resource
	Total	Payment	Payment				Total Fixed	Capacity Factor	Total Fixed	Levelized Fuel						Cost
Description	Capital Cost	Factor	($/kW-Yr)	O&M	Other	Total	($/kW-Yr)		Mills/kWh	¢/mmBtu	Mills/kWh	O&M ($/MWh)	Gas Transportation/ Wind Integration	Tax Credits	Environmental	(Mills/kWh)
West Side Options (1500')																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	869.90	63.17	$ 0.03	5.33	-	12.95	101.33
SCCT Aero	1,024	9.08%	$ 92.92	$ 9.04	$ 0.50	$ 9.54	$ 102.46	21%	55.70	869.90	85.02	$ 5.12	7.17	-	17.43	170.43
Intercooled Aero SCCT	956	9.08%	$ 86.77	$ 3.68	$ 0.50	$ 4.18	$ 90.95	21%	49.44	869.90	81.79	$ 2.46	6.90	-	16.77	157.36
Internal Combustion Engines	1,204	9.08%	$ 109.25	$ 12.80	$ 0.50	$ 13.30	$ 122.55	94%	14.88	869.90	73.94	$ 5.20	6.24	-	15.16	115.42
SCCT Frame (2 Frame "F")	679	8.62%	$ 58.53	$ 3.40	$ 0.50	$ 3.90	$ 62.43	21%	33.94	869.90	101.43	$ 4.07	8.56	-	20.79	168.78
CCCT (Wet "F" 1x1)	1,242	8.59%	$ 106.66	$ 11.62	$ 0.50	$ 12.12	$ 118.78	56%	24.21	869.90	63.52	$ 2.67	5.36	-	13.02	108.79
CCCT Duct Firing (Wet "F" 1x1)	507	8.59%	$ 43.53	$ 1.45	$ 0.50	$ 1.95	$ 45.48	16%	32.45	869.90	77.15	$ 0.36	6.51	-	15.82	132.28
CCCT (Wet "F" 2x1)	1,131	8.59%	$ 97.08	$ 7.07	$ 0.50	$ 7.57	$ 104.65	56%	21.33	869.90	61.75	$ 2.67	5.21	-	12.66	103.62
CCCT Duct Firing (Wet "F" 2x1)	570	8.59%	$ 48.98	$ 1.45	$ 0.50	$ 1.95	$ 50.93	16%	36.34	869.90	74.44	$ 0.36	6.28	-	15.26	132.68
CCCT (Wet "G" 1x1)	1,175	8.59%	$ 100.85	$ 6.13	$ 0.50	$ 6.63	$ 107.48	56%	21.91	869.90	59.89	$ 4.14	5.05	-	12.28	103.27
CCCT Duct Firing (Wet "G" 1x1)	497	8.59%	$ 42.69	$ 1.48	$ 0.50	$ 1.98	$ 44.68	16%	31.88	869.90	78.48	$ 0.33	6.62	-	16.09	133.39
CCCT Advanced (Wet)	1,297	8.59%	$ 111.36	$ 6.13	$ 0.50	$ 6.63	$ 117.99	56%	24.05	869.90	58.80	$ 4.14	4.96	-	12.06	104.01
CCCT Advanced Duct Firing (Wet)	636	8.59%	$ 54.64	$ 1.48	$ 0.50	$ 1.98	$ 56.62	16%	40.40	869.90	78.48	$ 0.33	6.62	-	16.09	141.91
Other - Renewables																
West Wind	2,612	8.72%	$ 227.59	$ 31.43	$ 27.74	$ 59.17	$ 286.76	29%	112.88	-	-	-	11.75	(20.70)	-	103.93
Biomass	3,347	8.10%	$ 271.22	$ 38.80	$ 0.50	$ 39.30	$ 310.52	91%	38.78	590.00	64.78	$ 0.96	-	(20.70)	34.16	117.97
West Side Geothermal (Green Field)	7,609	7.42%	$ 564.62	$ 221.70	$ 0.50	$ 222.20	$ 786.82	90%	99.80	-	-	$ 11.88	-	(20.70)	-	90.98
Compressed Air Energy Storage (CAES)	1,561	8.29%	$ 129.41	$ 3.45	$ 1.35	$ 4.80	$ 134.21	47%	32.81	869.90	104.21	$ 5.00	8.79	-	21.37	172.18
Hydrokinetic (Wave) - 21% CF	6,000	9.69%	$ 581.58	$ 180.00	$ 6.00	$ 186.00	$ 767.58	21%	417.25	-	-	-	-	-	-	417.25
West Side Options (Sea Level)																
Natural Gas																
Fuel Cell - Large	1,794	8.72%	$ 156.34	$ 8.40	$ 0.50	$ 8.90	$ 165.24	95%	19.86	869.90	63.17	$ 0.03	5.33	-	12.95	101.33
SCCT Aero	972	9.08%	$ 88.27	$ 8.59	$ 0.50	$ 9.09	$ 97.36	21%	52.93	869.90	85.02	$ 4.87	7.17	-	17.43	167.42
Intercooled Aero SCCT	908	9.08%	$ 82.43	$ 3.49	$ 0.50	$ 3.99	$ 86.43	21%	46.98	869.90	81.79	$ 2.35	6.90	-	16.77	154.78
Internal Combustion Engines	1,143	9.08%	$ 103.79	$ 12.80	$ 0.50	$ 13.30	$ 117.09	94%	14.22	869.90	73.94	$ 5.20	6.24	-	15.16	114.75
SCCT Frame (2 Frame "F")	645	8.62%	$ 55.61	$ 3.23	$ 0.50	$ 3.73	$ 59.34	21%	32.26	869.90	101.43	$ 3.87	8.56	-	20.79	166.90
CCCT (Wet "F" 1x1)	1,180	8.59%	$ 101.32	$ 11.07	$ 0.50	$ 11.57	$ 112.89	56%	23.01	869.90	63.52	$ 2.55	5.36	-	13.02	107.46
CCCT Duct Firing (Wet "F" 1x1)	482	8.59%	$ 41.35	$ 1.38	$ 0.50	$ 1.88	$ 43.23	16%	30.85	869.90	77.15	$ 0.34	6.51	-	15.82	130.66
CCCT (Wet "F" 2x1)	1,074	8.59%	$ 92.23	$ 6.73	$ 0.50	$ 7.23	$ 99.46	56%	20.27	869.90	61.75	$ 2.55	5.21	-	12.66	102.44
CCCT Duct Firing (Wet "F" 2x1)	542	8.59%	$ 46.53	$ 1.38	$ 0.50	$ 1.88	$ 48.42	16%	34.54	869.90	74.44	$ 0.34	6.28	-	15.26	130.87
CCCT (Wet "G" 1x1)	1,116	8.59%	$ 95.81	$ 5.84	$ 0.50	$ 6.34	$ 102.15	56%	20.82	869.90	59.89	$ 3.94	5.05	-	12.28	101.98
CCCT Duct Firing (Wet "G" 1x1)	472	8.59%	$ 40.56	$ 1.41	$ 0.50	$ 1.91	$ 42.47	16%	30.30	869.90	78.48	$ 0.31	6.62	-	16.09	131.80
CCCT Advanced (Wet)	1,232	8.59%	$ 105.79	$ 5.84	$ 0.50	$ 6.34	$ 112.13	56%	22.86	869.90	58.80	$ 3.94	4.96	-	12.06	102.62
CCCT Advanced Duct Firing (Wet)	605	8.59%	$ 51.91	$ 1.41	$ 0.50	$ 1.91	$ 53.82	16%	38.40	869.90	78.48	$ 0.31	6.62	-	16.22	140.03

Distributed Generation

Table 6.8 reports cost and performance attributes for small distributed standby generation, combined heat and power, and on-site solar supply-side resource options. Tables 6.9 and 6.10 present the total resource cost attributes for these resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2008 dollars. The resource costs are presented for both the \$8 and \$45 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs. Certain technologies were adjusted to reflect benefits that were identified outside of the Quantec DSM potential study and cost of emissions. Maintenance and forced outage data were taken from comparable technologies in the supply-side table. Additional explanatory notes for the tables are as follows:

- A 15-percent administrative cost (for fixed operation and maintenance) is included in the overall cost of the resources.
- The avoided transmission and distribution credit of \$23/kW-year is included in the resource costs to reflect a rough estimate of savings by avoiding transmission and distribution investments.
- Federal tax benefits are included for microturbines at \$200/kW capacity, while fuel cells receive \$500 per 0.05 kW of capacity.
- Installation costs for on-site (“micro”) solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. However, capital costs are adjusted downward to reflect federal and state tax benefits. The percentages applied included an 80 percent reduction to capital cost for Oregon, 31 percent for Utah, and 25 percent for all other states. The Quantec DSM potential study included the following benefits for commercial and residential customers:
  - Utah
    - *Commercial Credits:* The federal credit is 30 percent of the investment; the state credit is 1 percent of investment
    - *Residential Credits:* The federal credit is 30 percent of the investment up to \$2,000 for Residential Energy Efficiency; Utah receives up to \$2,000
  - Oregon
    - *Commercial Credits:* The federal credit is 30 percent of the investment; the state Business Credit is 50 percent of investment up to \$20 million received over 5 years; The Energy Trust of Oregon credit is \$1.25 per watt
    - *Residential Credits:* The federal credit is 30 percent of the investment up to \$2,000 for Residential Energy Efficiency; the state credit is 5 percent of investment; the Energy Trust of Oregon credit is \$2 per watt
  - Other States
    - *Commercial Credits:* The federal credit is 30 percent of the investment
    - *Residential Credits*: The federal credit is 30 percent of the investment up to \$2,000 for Residential Energy Efficiency

- The resource cost for Industrial Biomass reflects the Company’s recent avoided cost, which reflects the minimum price the Company would pay. Factoring in the income tax benefits would lower the resource cost below the Company’s avoided cost.

Table 6.8 – Distributed Generation Resource Options

(2008 Dollars)

Description	Installation Location	1st Year Avail.	Unit Size MW Average Cap. (MW)	Fuel	Design Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Capital Cost $/kW	Var. O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emissions			
												SO2	NOx	Hg	CO2
												lbs/MMBTU (Hg: lbs/Tbtu)			
Small Combined Heat & Power															
Reciprocating Engine	Utah	2008	0.6	Natural Gas	20	5,005	2%	3%	$ 1,969	-	$ 79.00	0.001	0.101	0.255	118.00
Reciprocating Engine	Wyoming	2008	0.6	Natural Gas	20	5,005	2%	3%	$ 1,969	-	$ 79.00	0.001	0.101	0.255	118.00
Reciprocating Engine	Oregon	2008	0.6	Natural Gas	20	5,005	2%	3%	$ 1,969	-	$ 79.00	0.001	0.101	0.255	118.00
Gas Turbine	Utah	2008	3.2	Natural Gas	20	6,600	2%	3%	$ 1,838	-	$ 58.00	0.001	0.050	0.255	118.00
Gas Turbine	Wyoming	2008	3.2	Natural Gas	20	6,600	2%	3%	$ 1,838	-	$ 58.00	0.001	0.050	0.255	118.00
Gas Turbine	Oregon	2008	3.2	Natural Gas	20	6,600	2%	3%	$ 1,838	-	$ 58.00	0.001	0.050	0.255	118.00
Microturbine	Utah	2008	0.2	Natural Gas	15	7,454	2%	3%	$ 2,831	-	$ 71.00	0.001	0.101	0.255	118.00
Microturbine	Wyoming	2008	0.2	Natural Gas	15	7,454	2%	3%	$ 2,831	-	$ 71.00	0.001	0.101	0.255	118.00
Microturbine	Oregon	2008	0.2	Natural Gas	15	7,454	2%	3%	$ 2,831	-	$ 71.00	0.001	0.101	0.255	118.00
Fuel Cell	Utah	2008	0.5	Natural Gas	10	5,706	2%	3%	$ 5,697	-	$ 17.00	0.001	0.003	0.255	118.00
Fuel Cell	Wyoming	2008	0.5	Natural Gas	10	5,706	2%	3%	$ 5,697	-	$ 17.00	0.001	0.003	0.255	118.00
Fuel Cell	Oregon	2008	0.5	Natural Gas	10	5,706	2%	3%	$ 5,697	-	$ 17.00	0.001	0.003	0.255	118.00
Commercial Biomass, Anaerobic Digester	Utah	2008	0.4	Biomass	15	-	10%	10%	$ 3,219	-	$ 67.00	-	-	-	-
Commercial Biomass, Anaerobic Digester	Wyoming	2008	0.4	Biomass	15	-	10%	10%	$ 3,219	-	$ 67.00	-	-	-	-
Commercial Biomass, Anaerobic Digester	Oregon	2008	0.4	Biomass	15	-	10%	10%	$ 3,219	-	$ 67.00	-	-	-	-
Industrial Biomass, Waste	Utah	2008	4.8	Biomass	15	-	5%	5%	$ 1,800	-	$ 39.00	-	-	-	-
Industrial Biomass, Waste	Wyoming	2008	4.8	Biomass	15	-	5%	5%	$ 1,800	-	$ 39.00	-	-	-	-
Industrial Biomass, Waste	Oregon	2008	4.8	Biomass	15	-	5%	5%	$ 1,800	-	$ 39.00	-	-	-	-
Solar															
Rooftop Photovoltaic	Utah	2008	0.005	Solar	25	-			$ 9,000	-	$ 100.00	-	-	-	-
Rooftop Photovoltaic	Wyoming	2008	0.005	Solar	25	-			$ 9,000	-	$ 100.00	-	-	-	-
Rooftop Photovoltaic	Oregon	2008	0.005	Solar	25	-			$ 9,000	-	$ 100.00	-	-	-	-
Water Heaters	Utah	2008	0.002	Solar	15	-			$ 3,500	-	-	-	-	-	-
Water Heaters	Wyoming	2008	0.002	Solar	15	-			$ 3,500	-	-	-	-	-	-
Water Heaters	Oregon	2008	0.002	Solar	15	-			$ 3,500	-	-	-	-	-	-
Attic Fans	Utah	2008	0.000010	Solar	10	-			$ 54,000	-	-	-	-	-	-
Attic Fans	Wyoming	2008	0.000010	Solar	10	-			$ 54,000	-	-	-	-	-	-
Attic Fans	Oregon	2008	0.000010	Solar	10	-			$ 54,000	-	-	-	-	-	-
Dispatchible Generators															
Dispatchible Standby Generators Existing	Utah	2008	1.0	Diesel	20	9,975			$ 250	-	$ 7.50	0.030	0.101	0.255	118.00
Dispatchible Standby Generators Existing	Wyoming	2008	1.0	Diesel	20	9,975			$ 250	-	$ 7.50	0.030	0.101	0.255	118.00
Dispatchible Standby Generators Existing	Oregon	2008	1.0	Diesel	20	9,975			$ 250	-	$ 7.50	0.030	0.101	0.255	118.00
Dispatchible Standby Generators New	Utah	2008	1.0	Diesel	20	9,975			$ 175	-	$ 5.00	0.030	0.101	0.255	118.00
Dispatchible Standby Generators New	Wyoming	2008	1.0	Diesel	20	9,975			$ 175	-	$ 5.00	0.030	0.101	0.255	118.00
Dispatchible Standby Generators New	Oregon	2008	1.0	Diesel	20	9,975			$ 175	-	$ 5.00	0.030	0.101	0.255	118.00

Table 6.9 – Distributed Generation Total Resource Costs, $8 CO_2 tax

(2008 Dollars)

	Capital Cost $/kW							Fixed Cost				Convert to Mills				Variable Costs			Total
						Payment	Annual Pmt	Fixed O&M $/kW-Yr			Total Fixed	Capacity	Ttl Fixed	Levelized Fuel		mills/kWh			Resource Cost
Description	Cap Cost	Tax Benefits	Transmission & Distribution Credit	Administrative	Net Capital Costs	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Factor	Mills/kWh	¢/mmBtu	Mills/kWh	O&M	Avoided Cost	Environmental	(Mills/kWh)
Small Combined Heat & Power																			
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	699.22	35.00	-	-	1.59	$ 76.04
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	699.22	35.00	-	-	1.59	$ 76.04
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	814.00	40.74	-	-	1.59	$ 81.79
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	699.22	46.15	-	-	2.09	$ 81.06
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	699.22	46.15	-	-	2.09	$ 81.06
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	814.00	53.72	-	-	2.09	$ 88.63
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	699.22	52.12	-	-	2.36	$ 104.78
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	699.22	52.12	-	-	2.36	$ 104.78
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	814.00	60.68	-	-	2.36	$ 113.33
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	699.22	39.90	-	-	1.81	$ 140.81
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	699.22	39.90	-	-	1.81	$ 140.81
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	814.00	46.45	-	-	1.81	$ 147.36
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	46.30	-	$ 46.30
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	58.37	-	$ 58.37
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	62.33	-	$ 62.33
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	46.30	-	$ 46.30
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	58.37	-	$ 58.37
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	62.33	-	$ 62.33
Solar																			
Rooftop Photovoltaic	$ 9,000	$ (2,790)	$ (264)	$ 1,350	$ 7,296	8.72%	$ 635.85	$ 100.00	-	$ 100.00	$ 735.85	14%	600.01	-	-	-	-	-	$ 600.01
Rooftop Photovoltaic	$ 9,000	$ (2,250)	$ (264)	$ 1,350	$ 7,836	8.72%	$ 682.92	$ 100.00	-	$ 100.00	$ 782.92	14%	638.38	-	-	-	-	-	$ 638.38
Rooftop Photovoltaic	$ 9,000	$ (7,200)	$ (264)	$ 1,350	$ 2,886	8.72%	$ 251.52	$ 100.00	-	$ 100.00	$ 351.52	13%	308.68	-	-	-	-	-	$ 308.68
Water Heaters	$ 3,500	$ (980)	$ (202)	$ 525	$ 2,843	11.41%	$ 324.31	-	-	-	$ 324.31	14%	264.44	-	-	-	-	-	$ 264.44
Water Heaters	$ 3,500	$ (875)	$ (202)	$ 525	$ 2,948	11.41%	$ 336.29	-	-	-	$ 336.29	14%	274.21	-	-	-	-	-	$ 274.21
Water Heaters	$ 3,500	$ (1,330)	$ (202)	$ 525	$ 2,493	11.41%	$ 284.39	-	-	-	$ 284.39	13%	249.73	-	-	-	-	-	$ 249.73
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$9,269.64	13%	8139.83	-	-	-	-	-	$ 8,139.83
Dispatchible Generators																			
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	3.19	$ 471.26
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	3.19	$ 471.26
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	3.19	$ 471.26
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	3.19	$ 318.01
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	3.19	$ 318.01
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	3.19	$ 318.01

Table 6.10 – Distributed Generation Total Resource Cost, $45 CO_2 Tax

(2008 Dollars)

	Capital Cost $/kW							Fixed Cost				Convert to Mills				Variable Costs			Total
						Payment	Annual Pmt	Fixed O&M $/kW-Yr			Total Fixed	Capacity	Ttl Fixed	Levelized Fuel		mills/kWh			Resource Cost
Description	Cap Cost	Tax Benefits	Transmission & Distribution Credit	Administrative	Net Capital Costs	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Factor	Mills/kWh	¢/mmBtu	Mills/kWh	O&M	Avoided Cost	Environmental	(Mills/kWh)
Small Combined Heat & Power																			
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	722.19	36.15	-	-	8.93	$ 84.53
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	722.19	36.15	-	-	8.93	$ 84.53
Reciprocating Engine	$ 1,969	$ -	$ (204)	$ 295	$ 2,060	11.27%	$ 232.08	$ 79.00	-	$ 79.00	$ 311.08	90%	39.46	869.90	43.54	-	-	8.93	$ 91.92
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	722.19	47.66	-	-	11.77	$ 92.25
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	722.19	47.66	-	-	11.77	$ 92.25
Gas Turbine	$ 1,838	$ -	$ (204)	$ 276	$ 1,910	11.27%	$ 215.11	$ 58.00	-	$ 58.00	$ 273.11	95%	32.82	869.90	57.41	-	-	11.77	$ 102.00
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	722.19	53.83	-	-	13.29	$ 117.42
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	722.19	53.83	-	-	13.29	$ 117.42
Microturbine	$ 2,831	$ (200)	$ (202)	$ 425	$ 2,854	11.41%	$ 325.53	$ 71.00	-	$ 71.00	$ 396.53	90%	50.30	869.90	64.84	-	-	13.29	$ 128.43
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	722.19	41.21	-	-	10.18	$ 150.49
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	722.19	41.21	-	-	10.18	$ 150.49
Fuel Cell	$ 5,697	$ (1,000)	$ (154)	$ 855	$ 5,398	14.96%	$ 807.73	$ 17.00	-	$ 17.00	$ 824.73	95%	99.10	869.90	49.64	-	-	10.18	$ 158.92
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	46.30	-	$ 46.30
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	58.37	-	$ 58.37
Commercial Biomass, Anaerobic Digester	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	80%	0.00	-	-	-	62.33	-	$ 62.33
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	46.30	-	$ 46.30
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	58.37	-	$ 58.37
Industrial Biomass, Waste	$ -	$ -	$ -	$ -	$ -	11.41%	-	-	-	-	-	90%	0.00	-	-	-	62.33	-	$ 62.33
Solar																			
Rooftop Photovoltaic	$ 9,000	$ (2,790)	$ (264)	$ 1,350	$ 7,296	8.72%	$ 635.85	$ 100.00	-	$ 100.00	$ 735.85	14%	600.01	-	-	-	-	-	$ 600.01
Rooftop Photovoltaic	$ 9,000	$ (2,250)	$ (264)	$ 1,350	$ 7,836	8.72%	$ 682.92	$ 100.00	-	$ 100.00	$ 782.92	14%	638.38	-	-	-	-	-	$ 638.38
Rooftop Photovoltaic	$ 9,000	$ (7,200)	$ (264)	$ 1,350	$ 2,886	8.72%	$ 251.52	$ 100.00	-	$ 100.00	$ 351.52	13%	308.68	-	-	-	-	-	$ 308.68
Water Heaters	$ 3,500	$ (980)	$ (202)	$ 525	$ 2,843	11.41%	$ 324.31	-	-	-	$ 324.31	14%	264.44	-	-	-	-	-	$ 264.44
Water Heaters	$ 3,500	$ (875)	$ (202)	$ 525	$ 2,948	11.41%	$ 336.29	-	-	-	$ 336.29	14%	274.21	-	-	-	-	-	$ 274.21
Water Heaters	$ 3,500	$ (1,330)	$ (202)	$ 525	$ 2,493	11.41%	$ 284.39	-	-	-	$ 284.39	13%	249.73	-	-	-	-	-	$ 249.73
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$ 9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$ 9,269.64	14%	7558.42	-	-	-	-	-	$ 7,558.42
Attic Fans	$ 54,000	$ -	$ (154)	$ 8,100	$ 61,946	14.96%	$9,269.64	-	-	-	$ 9,269.64	13%	8139.83	-	-	-	-	-	$ 8,139.83
Dispatchible Generators																			
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	17.81	$ 485.88
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	17.81	$ 485.88
Dispatchible Standby Generators Existing	$ 250	$ -	$ (211)	$ 38	$ 76	10.88%	$ 8.28	$ 7.50	$ 1.13	$ 8.63	$ 16.91	0.9%	211.35	2574	256.72	-	-	17.81	$ 485.88
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	17.81	$ 332.63
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	17.81	$ 332.63
Dispatchible Standby Generators New	$ 175	$ -	$ (211)	$ 26	$ (10)	10.88%	$ (1.10)	$ 5.00	$ 0.75	$ 5.75	$ 4.65	0.9%	58.10	2574	256.72	-	-	17.81	$ 332.63

Resource Option Description

Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical pulverized coal boilers (PC) and integrated gasification combined cycles (IGCC) in Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have risen by approximately 50% to 60% due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. Additionally the uncertainty of future carbon regulations and a difficulty in obtaining construction and environmental permits for coal based generation alternatives has encouraged the Company to postpone the selection of coal as a resource before 2020.

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

Carbon dioxide capture and sequestration technology represents a potential cost for new and existing coal plants if future regulations require it. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from the flue gas of conventional boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would bury the CO_2 underground for long-term storage and monitoring.

PacifiCorp and its parent Company MEHC are monitoring CO_2 capture technologies for possible retrofit opportunities at its existing coal-fired fleet, as well as applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO_2 removal becomes necessary in the future. An option to capture CO_2 at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a couple of large-scale sequestration projects in operation around the world and a number of these are in conjunction with enhanced oil recovery. Carbon capture and sequestration (CCS) is not considered a viable option before 2025 due to risk issues associated with technological maturity and underground sequestration liability.

An alternative to supercritical pulverized-coal technology for coal-based generation would be the use of IGCC technology. A significant advantage for IGCC when compared to conventional pulverized coal with amine-based carbon capture is the reduced cost of capturing carbon dioxide from the process. Gasification plants have been built and demonstrated around the world, primarily as a means of producing chemicals from coal. Only a limited number of IGCC plants have been constructed specifically for power generation. In the United States, these facilities have been demonstration projects and cost significantly more than conventional coal plants in both capital and operating costs. These projects have been constructed with significant funding from the federal government. A number of IGCC technology suppliers have teamed up with large constructor to form consortia who are now offering to build IGCC plants. A few years ago, these consortia were willing to provide IGCC plants on a lump-sum, turn-key basis. However, in today's market, the willingness of these consortia to design and construct IGCC plants on lump-sum turn key basis is in question. The costs presented in the supply-side resource options tables reflect recent studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp was selected by the Wyoming Infrastructure Authority (WIA) to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal was to develop a Section 413 project under the 2005 Energy Policy Act. PacifiCorp commissioned and managed feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Based on the results of initial feasibility studies, PacifiCorp declined to submit a proposal to the federal agencies involved in the Section 413 solicitation.

PacifiCorp is a member of the Gasification User's Association. In addition, PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables. Over the last two years PacifiCorp has help a series of public meetings as a part of an IGCC Working Group to help provide a broader level of understanding for this technology.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants (which are manifest in lower plant heat rates) are realized by (1) emphasizing continuous improvement in operations, and (2) upgrading components if economically justified. Such fuel efficiency improvements can result in a smaller emission footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units degrades gradually as components wear out over time. During operation, controllable process parameters are adjusted to optimize unit output and efficiency. Typical overhaul work that contributes to improved efficiency includes (1) steam turbine overhauls, (2) cleaning and repairing condensers, feed water heaters, and cooling towers and (3) cleaning boiler heat transfer surfaces.

When economically justified, efficiency improvements are obtained through major component upgrades. Examples include turbine upgrades using new blade and sealing technology, improved seals and heat exchange elements for boiler air heaters, cooling tower fill upgrades, and the addition of cooling tower cells. Such upgrade opportunities are analyzed on a case by case basis, and it is difficult to plan far in advance since decisions are tied to the existence of commercially-proven technology advancements available during a plant's next major overhaul cycle. PacifiCorp is taking advantage of improved upgrade technology through its "dense pack" coal plant turbine upgrade initiative. This initiative, to be completed by 2016, is factored into the 2008 IRP via a 170 MW coal plant capacity gain without a corresponding increase in fuel consumption, heat input, or emissions. Capacity expansion modeling to support the 2008 business plan indicated that this upgrade initiative was cost-effective. This resource is included in the current IRP models as a result.

Natural Gas

Natural gas generation options are numerous and a limited number of representative technologies are included in the supply-side resource options table. Simple cycle and combined cycle combustion turbines are included. A dry cooled combined cycle has been included. As with other generation technologies, the cost of natural gas generation has increased substantially from previous IRPs. Costs for gas generation have increased by 40% to 70%, depending on the option, due not only to general utility cost issues mentioned earlier, but also due to the decrease in coal-based projects thereby putting an increased demand on natural gas options that can be more easily permitted.

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

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

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of 14 machines at 10.9 megawatts. These machines are spark-ignited and have the advantages of a relatively attractive heat rate, a low emissions profile, and a high level of availability and reliability due to the number of machines. At present, fuel cells hold less promise due to high capital cost, partly attributable to the lack of production capability and continued development. Fuel cells are not ready for large scale deployment and are not considered available as a supply-side option until after 2013.

Combined cycle power plants options have been limited to 1x1 and 2x1 applications of "F" style combustion turbines and a "G" 1x1 facility. The "F" style machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the portfolio planning. Similarly, the "G" machine has been added to take advantage of the improved heat rate available from these more advanced gas turbines. The "G" machine is only presented as a 1x1 option to keep the size of the facility reasonable for selection as a portfolio option. These natural gas technologies are considered mature and installation lead times and capital costs are well known. The capital cost pressure currently being observed with constructing large coal-based generation plants is also being experienced with natural gas-fired plants.

Wind

Representation of wind projects was accomplished by developing a set of proxy wind sites composed of 100-MW blocks that could be selected as distinct resource options in the System Optimizer model. (Note that the 100-megawatt size reflects a suitable average size for modeling purposes, and does not imply that acquisitions are of this size.) Table 6.11 shows the regions in which wind resources are located and the representative capacity factors and quantity limits available to the System Optimizer model for selection. Note that these are aggregate limits for the entire modeling simulation period.

Table 6.11 – Proxy Wind Sites and Characteristics

Transmission Bubble	Location	Capacity Factor (%)	Maximum Capacity (MW)
Southwest Wyoming	Southwest Wyoming	24	1,400
		29	1,300
		35	1,300
Northeast Wyoming	Northeast Wyoming	24	1,400
		29	1,300
		35	1,300
Wyoming (Aeolus substation)	Southwest Wyoming	24	500
		29	500
		35	500
Goshen	Southeast Idaho	24	300
		29	300
Walla Walla	Southeast Washington	24	200
		29	300
		35	300
Yakima	South Central Washington	24	300
		29	200
West Main	Central Oregon	24	700
		29	500
		35	100
Mid-Columbia	Southwest Washington	24	100
		29	100
		35	100
Utah	Northern Utah	24	200
		29	200

For other wind resource attributes, the Company used multiple sources to derive attributes. Capital costs were derived from recent PacifiCorp projects and offers by developers. The EPRI TAG database was also used for certain cost figures, such as operation and maintenance costs. These costs were adjusted for current market conditions. Wheeling costs, applicable for wind projects cited in the west, and average incremental transmission costs for east-side resources needed beyond local interconnection and 230 kV step-up were included in the resources as appropriate.

Other Renewable Resources

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

Geothermal

The geothermal resources in Tables 6.2 and 6.3 represent a dual flash design with a wet cooling tower. The 35 MW values per project are suggested by engineering studies associated with a third unit at the Blundell site using technology similar to the Company's existing geothermal resources. The expansion of the Blundell site represents the best cost for geothermal energy currently available to the Company. Speculative risks associated with steam field development, as well as recent escalation in drilling costs, are not captured in the geothermal cost characterization.

The Company chose 100 MW as a reasonable upper bound for geothermal resource additions based on its experience with locating sizable quantities of geothermal generation either under development or suitable for development. Considerations included the Company's current view of realistic commercial resource opportunities given issues with project locations (development in sensitive areas and local opposition) and well performance related to temperature and resource adequacy as reported in recent geologic studies. Using the 35-MW representative size for a geothermal project yields a total of three geothermal projects as resource options, for a total of 105 MW. The Company has not yet conducted a geothermal commercial potential study looking at long-term prospects for geothermal energy utilizing both Blundell technology and other alternative geothermal technologies. One of the fundamental barriers to geothermal development is the difficulty in characterizing the type, quality, and conditions of a particular geothermal resource. This characterization requires a significant investment for well drilling and testing in order to develop a reliable and provable assessment.

Biomass and Solar

The biomass project would involve the combustion of whole trees that would be grown in a plantation setting, presumably in the Pacific Northwest. Three solar resources were defined. A concentrating photovoltaic (PV) system represents a utility scale PV resource. Optimistic performance and cost figures were used equivalent to the best reported PV efficiencies. Solar thermal projects are represented by both a solar concentrating design (trough system with natural gas backup) and a solar concentrating design (thermal tower arrangement with 6 hours of thermal storage). The system parameters for these systems were suggested by the WorleyParsons Group study and reflect current proposed projects in the desert southwest.

Energy Storage

The storage of energy is represented in the supply-side resource options table with three systems. The three systems are advanced battery applications, pumped hydro and compressed air energy storage. These technologies convert off-peak capacity to on-peak energy and thereby reduce the quantity of required overall capacity installed for peaking needs. Battery applications are typically smaller systems (less than 10 megawatts) that can have the most benefit in a smaller local area. Utility-scale demonstrations are just beginning to be conducted. Advanced battery applications are not available for selection in the modeling before 2014.

Pumped hydro is dependent on a good site combined with the ability to permit the facility, a process that can take many years to accomplish. PacifiCorp does not have any specific pumped hydro projects under development and does not consider this a viable resource before 2018 because of the necessary study and permitting issues.

Compressed air energy storage (CAES) can be an attractive means of utilizing intermittent energy. In a CAES plant, off-peak energy is used to pressurize an underground cavern. The pressurized air would then feed the power turbine portion of a combustion turbine saving the energy normally used in combustion turbine to compress air. CAES plants operate on a simple cycle basis and therefore displace peaking resources. A CAES plant could be built in conjunction with wind resources to level the production for such an intermittent resource. A CAES plant, whether associated with wind or not, would have to stand on its own for cost-effectiveness. Only two CAES plants have been built in the world. CAES is not considered practical for PacifiCorp until 2015.

Combined Heat and Power and Other Distributed Generation Alternatives

CHP are a small (ten megawatts or less) gas compressor heat recovery system using a binary cycle. These projects would be contracted at the customer site. They are labeled as Recovered Energy Generation (CHP) and utility cogeneration in the supply-side table.

A large CHP (40 to 120 megawatts) combustion turbine with significant steam based heat recovery from the flue gas has not been included in PacifiCorp's supply side table for the eastern service territory due to a lack of large potential industrial applications. These CHP opportunities are site-specific, and the generic options presented in the supply-side resource options table are not intended to represent any particular project or opportunity.

Small distributed generation resources are unique in that they reside at the customer load. The generation can either be used to reduce the customer load, such as net metering, or sold to the utility. Distributed standby generation provides peak load reductions over a contracted number of hours from on-site generators owned by the customer but managed by the utility. Small CHP resources generate electricity and utilize waste heat for space and water heating requirements. Fuel is either natural gas or renewable biogas. On-site solar resources, also referred to as "micro solar", include electric generation and energy-efficiency measures that use solar energy. The DG resources are up to 4.8 MW in size.

Table 6.12 shows the megawatt economic potential for distributed standby generation cited in the DSM potential study and the amount of the resource included in the IRP models. Due to the small potential in PacifiCorp's California, Yakima, Walla Walla, and Idaho service territories, these resources were excluded as model options. For distributed CHP, Tables 6.13 and 6.14 show the economic potential and amounts included in the IRP models, respectively. PacifiCorp used screening thresholds of 5 MW by state and 8 MW by technology to exclude resources from the IRP models. Such screening for small distributed generation resources was necessary to accommodate the large number of other resource options included in the IRP models. The size screening eliminated all but the West Main (Oregon and northern California) rooftop photovoltaic system.[30]

Table 6.12 – Standby Generation Economic Potential and Modeled Capacity

Year	Distributed Standby Generation (MW)					
	Cumulative Economic Potential			IRP Model Option		
	Existing	New	Total	Existing	New	Total
2009	6.9	9.9	16.8	5.7	9.5	15.2
2010	9.3	14.9	24.2	8.0	14.2	22.2
2011	11.8	19.9	31.6	10.3	18.9	29.2
2012	16.6	24.8	41.5	14.9	23.6	38.5
2013	21.5	29.8	51.3	19.4	28.4	47.8
2014	28.8	34.8	63.6	26.3	33.1	59.4
2015	36.1	39.7	75.9	33.1	37.8	71.0
2016	43.5	44.7	88.2	40.0	42.5	82.6
2017	50.8	49.7	100.5	46.9	47.3	94.1
2018	50.8	54.6	105.4	46.9	52.0	98.9
2019	50.8	59.6	110.4	46.9	56.7	103.6
2020	50.8	64.6	115.4	46.9	61.5	108.3
2021	50.8	69.5	120.3	46.9	66.2	113.0
2022	50.8	74.5	125.3	46.9	70.9	117.8
2023	50.8	79.5	130.3	46.9	75.6	122.5
2024	50.8	84.4	135.2	46.9	80.4	127.2
2025	50.8	89.4	140.2	46.9	85.1	132.0
2026	50.8	94.4	145.2	46.9	89.8	136.7
2027	50.8	99.3	150.1	46.9	94.6	141.4
2028	50.8	99.3	150.1	46.9	99.5	146.4

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[30] As a sensitivity test, the Company allowed its capacity expansion model to select from the entire set of micro-solar resources given the input assumptions from which the 2008 IRP preferred portfolio was derived. The model did not choose any micro-solar resources. This result is due to the higher fixed costs and lower availability relative to small competing resources such as CHP and DSM.

Table 6.13 – Distributed CHP Economic Potential (MW)

Year	Economic Potential (MW)									
	Combined Heat & Power (CHP)						On-Site Solar			Total
	Reciprocating Engine	MicroTurbine	Fuel Cell	Gas Turbine	Industrial Biomass	Anaerobic Digesters	Photovoltaic (PV)	Solar Water Heaters	Solar Attic Fans	
2009	0.3	0.0	0.0	0.0	0.4	0.0	0.2	0.0	0.0	1.1
2010	1.4	0.2	0.1	0.1	1.9	0.1	0.8	0.1	0.0	4.7
2011	3.0	0.4	0.2	0.2	4.1	0.3	1.6	0.2	0.1	10.0
2012	6.2	0.8	0.4	0.4	8.3	0.5	2.9	0.3	0.1	20.0
2013	10.5	1.3	0.7	0.7	14.2	0.9	4.3	0.4	0.2	33.2
2014	14.8	1.8	1.0	1.0	20.0	1.3	5.9	0.5	0.2	46.5
2015	19.1	2.4	1.3	1.3	25.8	1.6	7.4	0.7	0.3	59.9
2016	23.5	2.9	1.6	1.6	31.6	2.0	9.1	0.8	0.3	73.4
2017	27.8	3.4	1.9	1.9	37.5	2.4	10.7	0.9	0.3	86.8
2018	32.1	4.0	2.2	2.2	43.3	2.7	12.3	1.0	0.4	100.2
2019	36.4	4.5	2.5	2.5	49.1	3.1	13.6	1.1	0.4	113.3
2020	40.7	5.0	2.8	2.8	55.0	3.4	14.7	1.2	0.4	126.1
2021	45.1	5.6	3.1	3.1	60.8	3.8	15.7	1.2	0.5	138.8
2022	49.4	6.1	3.4	3.4	66.6	4.2	16.4	1.3	0.5	151.2
2023	53.1	6.5	3.7	3.6	71.6	4.5	17.0	1.3	0.5	161.9
2024	56.2	6.9	3.9	3.8	75.8	4.8	17.6	1.3	0.5	170.8
2025	58.0	7.2	4.0	3.9	78.3	4.9	18.0	1.3	0.5	176.2
2026	59.9	7.4	4.2	4.1	80.8	5.1	18.4	1.4	0.5	181.6
2027	61.7	7.6	4.3	4.2	83.3	5.2	18.8	1.4	0.5	187.1
2028	63.6	7.8	4.4	4.3	85.9	5.4	19.2	1.4	0.5	192.6

Table 6.14 – Distributed CHP Resources Included as IRP Model Options

Year	IRP Model Options (MW)			
	Combined Heat & Power (CHP)		On-Site ("Micro") Solar	Total
	Reciprocating Engine	Industrial Biomass	Photovoltaic (PV)	
2009	0.3	0.3	0.2	0.8
2010	1.2	1.5	0.7	3.4
2011	2.7	3.2	1.4	7.2
2012	5.4	6.6	2.5	14.5
2013	9.2	11.1	3.7	24.1
2014	13.0	15.7	5.0	33.8
2015	16.8	20.3	6.4	43.6
2016	20.6	24.9	7.9	53.4
2017	24.4	29.5	9.2	63.2
2018	28.2	34.1	10.6	73.0
2019	32.1	38.7	11.8	82.5
2020	35.9	43.3	12.7	91.8
2021	39.7	47.8	13.5	101.0
2022	43.5	52.4	14.2	110.1
2023	46.7	56.4	14.7	117.8
2024	49.4	59.6	15.2	124.3
2025	51.1	61.6	15.5	128.2
2026	52.7	63.6	15.9	132.2
2027	54.3	65.5	16.3	136.1
2028	56.0	67.6	16.6	140.2

Nuclear

An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based recent internal studies, press reports and information from a paper prepared by the Uranium Information Centre Ltd., "The Economics of Nuclear Power," May 2008. A 1,600 MW plant is characterized utilizing advanced nuclear plant designs. Nuclear power is not considered a viable option in the PacifiCorp service territory before 2025.

DEMAND-SIDE RESOURCES

Resource Options and Attributes

Source of Demand-side Management Resource Data

Demand-side resource opportunity estimates used in the development of the 2008 IRP were derived from data provided from the "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in June 2007 (DSM potential study). Preliminary results from the DSM potential study were initially incorporated in the 2007 IRP Update. However, these estimates were not modeled under the prescribed supply-curve methodology until the development of the 2008 IRP. The DSM potential study provided a broad estimate of the size, type, location and cost of demand-side resources. The demand-side resource information was converted into supply-curves by type of DSM; e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves

Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and costs of resources. Supply curves incorporate a linear relationship between quantities and costs (at least up to the maximum quantity available) to help identify at any particular cost how much of a particular resource can be acquired. Resource modeling utilizing supply curves allows utilities to sort out and select the least-cost resources (products and quantities) based on each resource's cost versus quantity in comparison against the supply curves of alternative and competing resource types.

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to demand-side supply curves include:

- Resource quantities available in year one—either megawatts or megawatt-hours— recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year
- Resource quantities available over time; for example, Class 2 energy-based resource measure lives
- Seasonal availability and hours available (Class 1 and Class 3 capacity resources)
- The shape or hourly contribution of the resource (load shape of the Class 2 energy resource)
- Levelized resource costs (dollars per megawatt per year for Class 1 and 3 capacity resources, or dollars per megawatt-hour for Class 2 energy resources)

Once developed, demand-side resource supply curves are treated like any other discrete supply-side resource in the IRP modeling environment. A complicating factor for modeling is that the DSM supply curves must be configured to meet the input specifications for two models: the System Optimizer capacity expansion optimization model, and the Planning and Risk production cost simulation model.

Class 1 DSM Capacity Supply Curves

Supply curves were created for four discrete Class 1 DSM products: residential air conditioning load control, irrigation load control, dispatchable commercial curtailment, and commercial and industrial thermal energy storage. The potentials and costs for each product were provided at the state level resulting in four products across six states, or twenty-four supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of forty Class 1 DSM supply curves were used in the 2008 IRP modeling process.

The starting point for supply curve development was DSM product information originally used for PacifiCorp's 2007 IRP. This information was further refined based on the following:

- Updated costs
- Customer surveys and acceptance data from the DSM potential study information
- Adjustments to DSM potential study results based on amended assumptions
- Another years experience delivering Class 1 DSM products
- The 2007 IRP modeling results.

In developing information on the four products and creation of supply curves, assumption changes (from those used in the DSM potential study) were made to two of the four products. The net potential for irrigation load control in the east was increased, as was the cost, to recognize the percentage of customers expected to select a dispatchable control option over a scheduled firm control option. In a second case, a new Class 1 product was created in order to incorporate the potential from a Class 3 product, commercial curtailment, for base resource consideration. The product recognizes how the Company intends to pursue, through program design, available commercial control opportunities (e.g. leverage controllable commercial loads using customer energy management systems combined with contracts for utility dispatched operation of customer distributed standby generators.)

The potential and cost of the Class 3 commercial curtailment product was used to create the new Class 1 product for three reasons. First, the potential captured in the Class 3 product was assumed to come from customer control of end-use equipment, not from any distributed standby generation capabilities. Second, the potential for distributed standby generation was included in the IRP model as a supply-side resource option. (It is already captured as a model resource). Third, the levelized cost for the Class 3 commercial curtailment product is in the same range as the levelized cost for distributed standby generation; approximately $50-$60 per kilowatt per year.

Other product price differences between west and east control areas were driven by resource differences in each market, such as irrigation pump sizes, types of pumping, and product performance differences (for example, residential air conditioning load control in the west is nearly twice the cost of east-side programs due to climatic differences that lead to less control per installed switch.) Pricing is also impacted by resource opportunity differences. The DSM potential study assumed the same fixed costs regardless of quantify of a particular product available. Therefore, the weighted average cost per control area for products with less opportunity in a particular state have a higher cost per kilowatt-year for that product.

The combination residential air conditioning and electric water heating dispatchable load control product was not provided to the System Optimizer model as a resource option for either control area. In the west, electric water heating control wasn't included as it adds little additional load for the cost, and electric water heating market share continues to decline each year as a result of conversions to gas. In the east, electric water heating control wasn't included because (1) the market potential is very small. (It is predominantly a gas water heating market), (2) an established program already exists that doesn't include a water heater control component, and (3) the potential identified is assumed to be located in areas where gas is not available; such as more rural and mountainous areas where direct load control paging signals are less reliable.

Tables 6.15 and 6.16 show the summary level Class 1 DSM program information, by control area, used in the development of the Class 1 resources supply curves. As previously noted, each of the products were further broken down by quantity available by state and load area in order to provide the model with location-specific details.

Table 6.15 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential Air Conditioning	Yes, with combo AC & water heating	Summer 40, not to exceed 6 hours per day	June 1 to Sept. 15	11	$165	2009
Irrigation (50% dispatchable and 50% scheduled firm)	No	Summer 40, not to exceed 6 hours per day	June 1 to Sept. 15	20	$50	2009
Commercial Curtailment (combination dispatchable product, excludes DSG in potential but will include in program to design)	Yes, with C&I Direct Load Control, Thermal Energy Storage, demand buyback, critical peak pricing, real-time pricing, and distributed standby generation	Summer and winter 40, 80 hours total. Not to exceed 6 hours per day	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	5	$61	2009
Commercial Thermal Energy Storage		Summer 40	June 1 to Sept. 15	2	$150	2009

[1] These costs are before a credit of $23/KW-year is applied for avoided transmission and distribution investment costs.

Table 6.16 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential Air Conditioning	Yes, with combo AC & WH	Summer 40, not to exceed 6 hours per day	Jun 1 to Sept. 15	47	$93	2009
Irrigation (50% dispatchable and 50% scheduled firm)	No	Summer 40, not to exceed 6 hours per day	June 1 to Sept. 15	45	$57	2009
Commercial Curtailment (combination dispatchable product, excludes DSG in potential but will include in program to design)	Yes, with C&I Direct Load Control, Thermal Energy Storage, demand buyback, critical peak pricing, real-time pricing, and distributed standby generation	Summer and winter 40, 80 hours total. Not to exceed 6 hours per day	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	38	$59	2009
Commercial Thermal Energy Storage		Summer 40	June 1 to Sept. 15	7	$153	2009

[1] These costs are before a credit of $23/KW-year is applied for avoided transmission and distribution investment costs.

To configure the supply curves for use in the System Optimizer model, there are a number of data conversions and resource attributes that are required by the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in $/kW-month. A credit of $23/kW-year for avoided transmission and distribution investment costs is also applied against the cost.[31] The following are the primary model attributes required by the model:

- The Capacity Planning Factor (CPF): This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Class 1 and 3 DSM programs, this parameter is set to 1 (100 percent).
- Additional reserves: This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.
- Daily and annual energy limits: These parameters, expressed in gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.

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[31] The Northwest Power and Conservation Council (NWPCC) and the Energy Trust of Oregon (ETO) use this value for their DSM avoided cost calculations.

- Nameplate capacity (MW) and service life (years)
- Maximum Annual Units: This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- First year and month available/last year available
- Fractional Units First Year: This parameter tells the model the first year in which a fractional quantity of the resource (as opposed to an integer quantity) can be selected. Year 2008 is entered in order to make these DSM resource options fractionally available in all years.

After the model has selected DSM resources, a program converts the resource attributes and quantities into a data format suitable for direct import into the Planning and Risk model.

Class 3 DSM Capacity Supply Curves

This DSM resource type consists of 50 distinct supply curves, reflecting a combination of products, states, and load areas. The Class 3 DSM programs modeled include the following:

- Residential time-of-use rates (Res RTP)
- Residential critical peak pricing (CPP)
- Commercial and industrial critical peak pricing (C&I CPP)
- Commercial and industrial real-time pricing (C&I RTP)
- Commercial and industrial demand buyback (C&I DBB)

In providing the data for the construction of Class 3 DSM supply curves, the Company did not net-out one product's resource potential against a competing product. As Class 3 DSM resource selections are not included as base resources for planning purposes, not taking product interactions into consideration poised no risk of over-reliance (or double counting the potential) of these resources in the final resource plan. For instance, in the development of the supply curves for residential time-of-use the program's market potential was not adjusted by the market potential or quantity available of a lesser-cost alternative, residential critical peak pricing.

Market potentials and costs for each of the five Class 3 DSM programs modeled were taken from the estimates provided in the DSM potential study and evaluated independently as if it were the only resource available targeting a particular customer segment.

Product price differences between west and east control areas were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in which it is offered regardless of quantify available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year for that product.

Tables 6.17 and 6.18 show the summary level Class 3 DSM program information, by control area, used in the development of the Class 3 resources supply curves. As previously noted, each of the products were further broken down by quantify available by state and load bubble in order to provide the model with location specific information.

Table 6.17 – Class 3 DSM Program Attributes West Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential TOU	Yes, with Res CPP and Res A/C DLC	N/A	Year around	8	$173	2009
Residential CPP	Yes, with Res TOU and Res A/C DLC	Summer 40	June 1- Sept. 15	22	$91	2009
Commercial and Industrial CPP	Yes, with C&I RTP, DBB and commercial curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	9	$33	2009
Commercial and Industrial RTP	Yes, with C&I CPP, DBB and C&I curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	1	$8	2009
Commercial and Industrial DBB	Yes, with C&I CPP and RTP and C&I curtailment	Summer and winter 25, 50 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	10	$18	2009

[1] These costs are before a credit of $23/kW-year is applied for avoided transmission and distribution investment costs.

Table 6.18 – Class 3 DSM Program Attributes East Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)[1]	Year Available
Residential TOU	Yes, with Res CPP and Res A/C DLC	N/A	Year around	11	$166	2009
Residential CPP	Yes, with Res TOU and Res A/C DLC	Summer 40	June 1- Sept. 15	30	$88	2009
Commercial and Industrial CPP	Yes, with C&I RTP, DBB and commercial curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	61	$12	2009
Commercial and Industrial RTP	Yes, with C&I CPP, DBB and C&I curtailment	Summer and winter 40, 80 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	14	$6	2009
Commercial and Industrial DBB	Yes, with C&I CPP and RTP and C&I curtailment	Summer and winter 25, 50 hours total	June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29)	27	$18	2009

[1] These costs are before a credit of $23/kW-year is applied for avoided transmission and distribution investment costs.

System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs. The data export program converts the Class 3 DSM programs selected by the model into a data format for import into the Planning and Risk model.

Class 2 DSM, Capacity Supply Curves

The 2008 IRP represents the first time the Company has utilized the supply curve methodology in the evaluation and selection of Class 2 DSM energy products. The DSM potential study provided the information to fully assess the contribution of Class 2 DSM resources over IRP planning horizons. Class 2 DSM resource data was provided by state down to the individual measure and facility levels; e.g., specific appliances, motors, air compressors for residential buildings, small offices, etc. In all, the DSM potential study provided Class 2 DSM resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming
- **Measure:**
  - Sixty-two residential measures
  - Seventy-eight commercial measures
  - Thirteen industrial measures
  - Three irrigation measures
- **Facility type:**
  - Six residential facility types
  - Twenty four commercial facility types
  - Twenty eight industrial facility types
  - Two irrigation facility types

The DSM potential study also provided total resource costs, which included both measure cost and a 15 percent adder for administrative costs levelized over measure life at PacifiCorp's cost of capital, consistent with the treatment of supply-side resource costs.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 9.9 million MWh. The technical potential represents the total universe of possible savings before adjustments for what is cost-effective to pursue (economic), likely to be realized (achievable), and impacts of emerging codes and standards such as the 2007 Energy Policy Act, whose impact full wasn't known at the time the DSM potential study was completed.

Despite the granularity of Class 2 DSM resource information available, it was impractical to use this much information in the development of Class 2 DSM resource supply curves. The combination of measures by facility type and state resulted in 12,500 distinct measures that could be modeled using the supply curve methodology.[32] This many supply curves is impossible to handle with PacifiCorp's IRP models. To reduce the resource options for consideration, while not losing the overall resource quantity available, the decision was made to consolidate like meas-

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[32] Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

ures (by weighted-average load shapes and lives) and costs of sets of measures into bundles to reduce the number of combinations to a more manageable number.

The bundles were developed based on Class 2 DSM potential study technical potentials (all economic screens were removed). The achievable assumption was adjusted from that estimated in the DSM potential study to eighty-five percent of the technical potential to account for the practical limits on acquiring all resources in all years. The assumption is consistent with regional planning assumptions in the Northwest. Five cost bundles, across five states, over twenty years equates to 500 supply curves before allocating across the Company load areas shown in Table 6.19.

Table 6.19 – Load Area Energy Distribution by State

State	Goshen	Utah	Walla Walla	West Main	Wyoming	Yakima
CA				100%		
OR			4%	96%		
ID	42%	58%				
UT		100%				
WA			25%			75%
WY		18%			82%	

After the load areas are accounted for (with some states served in more than one load area as noted in table 6.20), the number of supply curves grew to 800, excluding Oregon.

Table 6.20 shows the Class 2 DSM cost bundles used in the 2008 IRP and the associated bundle price. The bundle price can be interpreted as the marginal levelized cost for the group of measures. These prices, adjusted for the $23/kW-year transmission/distribution investment deferral benefit, represent the Class 2 DSM price inputs for the IRP models.

Table 6.20 – Class 2 DSM Cost Bundles and Bundle Prices

Class 2 DSM Cost Bundle	Resource Cost Range	Bundle Price ($/MWh)
Cost Bundle 1	$0.01/kWh to $0.07/kWh	$70
Cost Bundle 2	$0.07/kWh to $0.09/kWh	$90
Cost Bundle 3	$0.09/kWh to $0.11/kWh	$110
Cost Bundle 4	$0.11/kWh to $0.13/kWh	$130
Cost Bundle 5	$0.13/kWh to $0.15/kWh	$150
Cost Bundle 6	$0.15/kWh to $0.18/kWh	$180

Class 2 DSM resources in Oregon are acquired on behalf of the Company through Energy Trust of Oregon programs. To avoid duplicative potential assessment efforts the scope of PacifiCorp's DSM potential study excluded the analysis and evaluation of Class 2 resource potentials in Oregon. As a result, the Company relied on resource potential information provided by the Energy Trust of Oregon. The ETO economically screened their Oregon Class 2 DSM supply curves by using values compiled from regional and utility-specific valuation data.

The ETO provided the Company one cost bundle, weighted and shaped by the end-use measure potential for each year over a twenty-year horizon. Allocating these resources over two load areas in Oregon for consistency with other modeling efforts generated an additional 40 Class 2 supply curves (one cost bundle multiplied by two load areas multiplied by twenty years).

Table 6.21 shows the peak megawatt capacity represented by the supply curves for each state.

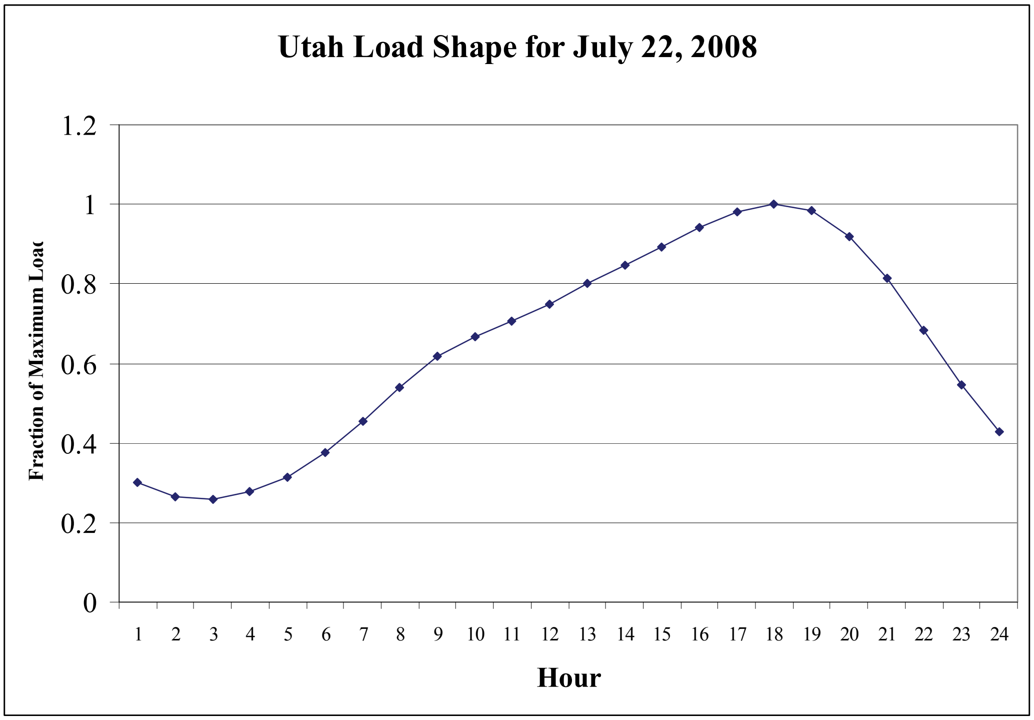
Table 6.21 – Class 2 DSM Supply Curve Capacities by State

State	Capacity (MW)
California	47
Idaho	143
Oregon	472
Utah	1,718
Washington	255
Wyoming	290
Total	2,916

In addition to the program attributes described for the Class 1 and 3 DSM resources, the Class 2 DSM supply curves also have load shapes describing the available energy savings on an hourly basis. For System Optimizer, each supply curve is associated with an annual hourly (“8760”) load shape configured to the 2008 calendar year. These load shapes are used by the model for each simulation year. In contrast, the Planning and Risk model requires for each supply curve a load shape that covers all 20 years of the simulation.

The load shape is composed of fractional values that represent each hour’s demand divided by the maximum demand in any hour for that shape. For example, the hour with maximum demand would have a value of 1.00 (100%), while an hour with half the maximum demand would have a value of 0.50 (50%). Summing the fractional values for all of the hours, and then multiplying this result by peak-hour demand, produces the annual energy savings represented by the supply curve. Figure 6.2 shows the Utah load shape for a representative day: July 22, 2008.

Figure 6.2 – Utah Load Shape



TRANSMISSION RESOURCES

While the Energy Gateway Transmission project was treated as part of the base topology for the IRP models, PacifiCorp included three transmission options that the System Optimizer could select. These options were recommended by PacifiCorp's Transmission Department as additional potential investments to supplement the Gateway project. The first option was an incremental addition to the Energy Gateway West project. This expansion option consisted of a 750 MW capacity increase from Path C in Idaho/northern Utah to the West Main load area, representing Oregon and northern California. This option was available beginning in 2015. The other two options, not associated with the Energy Gateway project, consisted of incremental 200 MW and 400 MW capacities for a Walla Walla to West Main transmission project available beginning in 2014.

MARKET PURCHASES

Resource Option Selection Criteria

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions. Table 6.22 shows the front office transaction resources included in the IRP models. Note that the Table distinguishes FOT resource assumptions made in February 2009 to support additional portfolio analysis based on termination of the 2012 Lake Side II CCCT construction contract. East-side FOT assumption changes were prompted by additional transmission availability from Mona to Utah for which the Company recently became aware.

Table 6.22 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub or Load Area	Product Type	Maximum Available Capacity (MW)	Availability
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	400	2009-2028
California Oregon Border (COB)	3rd Quarter Heavy Load Hour or Flat Annual	400	2009-2028
West Main	3rd Quarter Heavy Load Hour	50	2009-2028
Mead	3rd Quarter Heavy Load Hour	600	2017-2028
Mona	3rd Quarter Heavy Load Hour	200	2009-2028
Utah	3rd Quarter Heavy Load Hour	50	2009-2028
Modifications to Support 2012 Gas Resource Deferral Strategy			
Nevada Utah Border (NUB)	3rd Quarter Heavy Load Hour	164 1/	2012
Nevada Utah Border (NUB)	3rd Quarter Heavy Load Hour	579 2/	2013
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	400	2009-2012
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	775 (400 + 375 with 10% price premium)	2012-2013
Mid-Columbia	3rd Quarter Heavy Load Hour or Flat Annual	400	2014-2028

1/ Supported by completion of reactive compensation installation at Camp Williams substation in Utah, and anticipated 300 MW of additional firm transmission from Mead to NUB provided by Nevada Power.

2/ Supported by completion of the Mona to Oquirrh transmission line by the end of 2012, and anticipated 300 MW of additional firm transmission from Mead to NUB provided by Nevada Power.

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

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

The temporary increase in Mid-Columbia FOT market depth, from 400 MW to 775 MW in both 2012 and 2013, is accompanied by an assumed 10 percent price premium.

PacifiCorp examined the recent Mid-Columbia transaction history for forward third-quarter heavy load hour (HLH) products to support this short-term increase.[33] For example, according to the Intercontinental Exchange (ICE), 2008 transaction volumes reached 3,725 MW for third-quarter HLH products delivered in 2009.

Resource Options and Attributes

Two front office transaction types were included for portfolio analysis: an annual flat product, and a HLH 3rd quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, 6 days per week from July through September. Because these products are assumed to be firm for this IRP, the capacity contribution of front office transactions is grossed up for purposes of meeting the planning reserve margin. For example, a 100 MW front office transaction is treated as a 112 MW contribution to meeting PacifiCorp's load obligation plus a 12 percent planning reserve margin, with the selling counterparty holding the reserves necessary to make the product firm.

Prices for front office transaction purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[34] In formulating market purchase options for the IRP models, the Company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the 2008 All-Source RFP, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP.

Resource Description

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

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[33] HLH is the daily time block, hour-ending 7 am – 10 pm, for Monday through Saturday, excluding NERC-observed holidays.

[34] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.

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

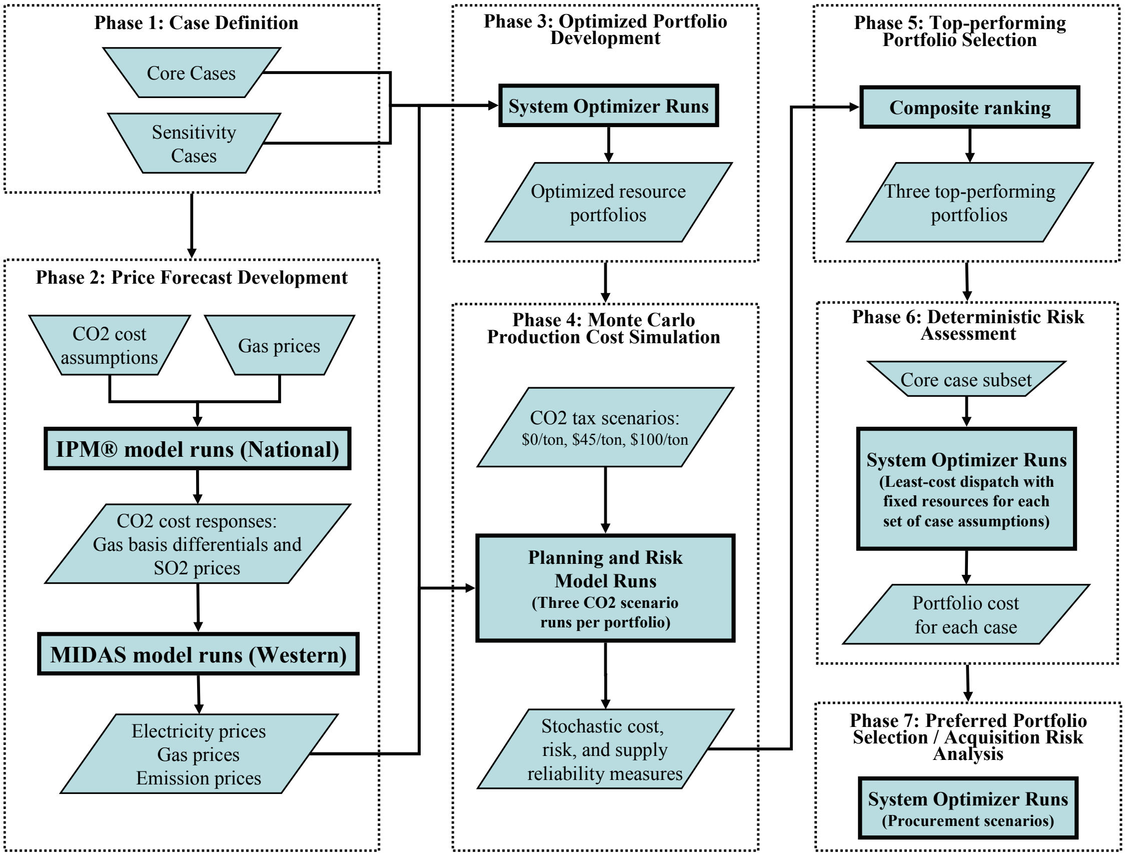
7. MODELING AND PORTFOLIO EVALUATION APPROACH

INTRODUCTION

The IRP modeling effort seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported portfolio performance evaluation. The information drawn from this process, summarized in Chapter 8, was used to help determine PacifiCorp's preferred portfolio and support the analysis of near-term resource acquisition risks.

The 2008 IRP modeling effort consists of seven phases: (1) define input scenarios—referred to as *cases*—characterized by alternative carbon dioxide costs, commodity gas prices, wholesale electricity prices, load growth trends, and other cost drivers, (2) case-specific price forecast development, (3) optimized portfolio development for each case using PacifiCorp's System Optimizer capacity expansion model, (4) Monte Carlo production cost simulation of each optimized portfolio to support stochastic risk analysis, (5) selection of top-performing portfolios using a composite ranking scheme that incorporates stochastic portfolio cost and risk assessment measures, (6) deterministic risk analysis using the System Optimizer, and (7) preferred portfolio selection, followed by acquisition risk analysis of preferred portfolio resources. Figure 7.1 presents the seven phases in flow chart form, showing the main process steps, data flows, and models involved for each phase. General modeling assumptions and price inputs are covered first in this chapter, followed by a profile of each modeling phase.

Figure 7.1 – Modeling and Risk Analysis Process



GENERAL ASSUMPTIONS AND PRICE INPUTS

Study Period and Date Conventions

PacifiCorp executes its IRP models for a 20-year period beginning January 1, 2009 and ending December 31, 2028. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year. The System Optimizer model requires in-service dates designated as the first day of a given month, while the Planning and Risk production cost simulation model allows any date.

Escalation Rates and Other Financial Parameters

Inflation Rates

Integrated resource planning model simulations and price forecasts reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. For the System Optimizer model, a single escalation rate value is used. This value, 1.9 percent, is estimated as the average of the annual corporate inflation rates for the period 2009 to 2030, using PacifiCorp's June 2008 inflation curve. For the Planning and Risk model, the full series of annual values from 2009 through 2028 is used.

Discount Factor

The rate used for discounting in financial calculations is PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2008 IRP is 7.4 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[35]

Federal and State Renewable Resource Tax Incentives

In October 2008, the U.S. Congress provided a one-year extension of the renewable Production Tax Credit (PTC) through December 31, 2009. In February 2009, Congress granted another extension through December 31, 2012. The current tax credit of $21/MWh, which applies to the first 10 years of commercial operation, is converted to a levelized net present value and added to the resource capital cost for entry into the System Optimizer model. The renewable PTC, or an equivalent federal financial incentive, is assumed to be available for all years in the study period.

The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) allows utilities to claim the 30-percent investment tax credit for solar facilities placed in service by January 1, 2017. This tax credit is factored into the capital cost for solar resource options in the System Optimizer model.

A number of state incentive programs are also included into the renewable resource capital costs for eligible facilities. These programs include the following

- **Utah** – The current production tax credit for wind, geothermal, and solar facilities located in Utah is $3.5/MWh over 4 years. There is no sunset provision for this tax credit.

- **Oregon** – Oregon's Business Energy Tax Credit (BETC) provides for an investment tax credit of 50 percent of qualifying costs for projects sited in Oregon up to $20 million for a total credit of $10 million. Projects receive up to $2 million per year over 5 years. Qualifying

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[35] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

projects include wind, solar, hydro, geothermal, and biomass. Projects are on a first come first served basis up to the Oregon's annual allocated dollars of tax benefits. There is no sunset provision for this credit, but the cap is likely to change from time to time.

- **Idaho** – 3% Investment Tax Credit (ITC) provision on tangible personal property. Credit is available to all construction projects and not unique to renewable projects.

Asset Lives

Table 7.1 lists the generation resource asset book lives assumed for levelized fixed charge calculations.

Table 7.1 – Resource Book Lives

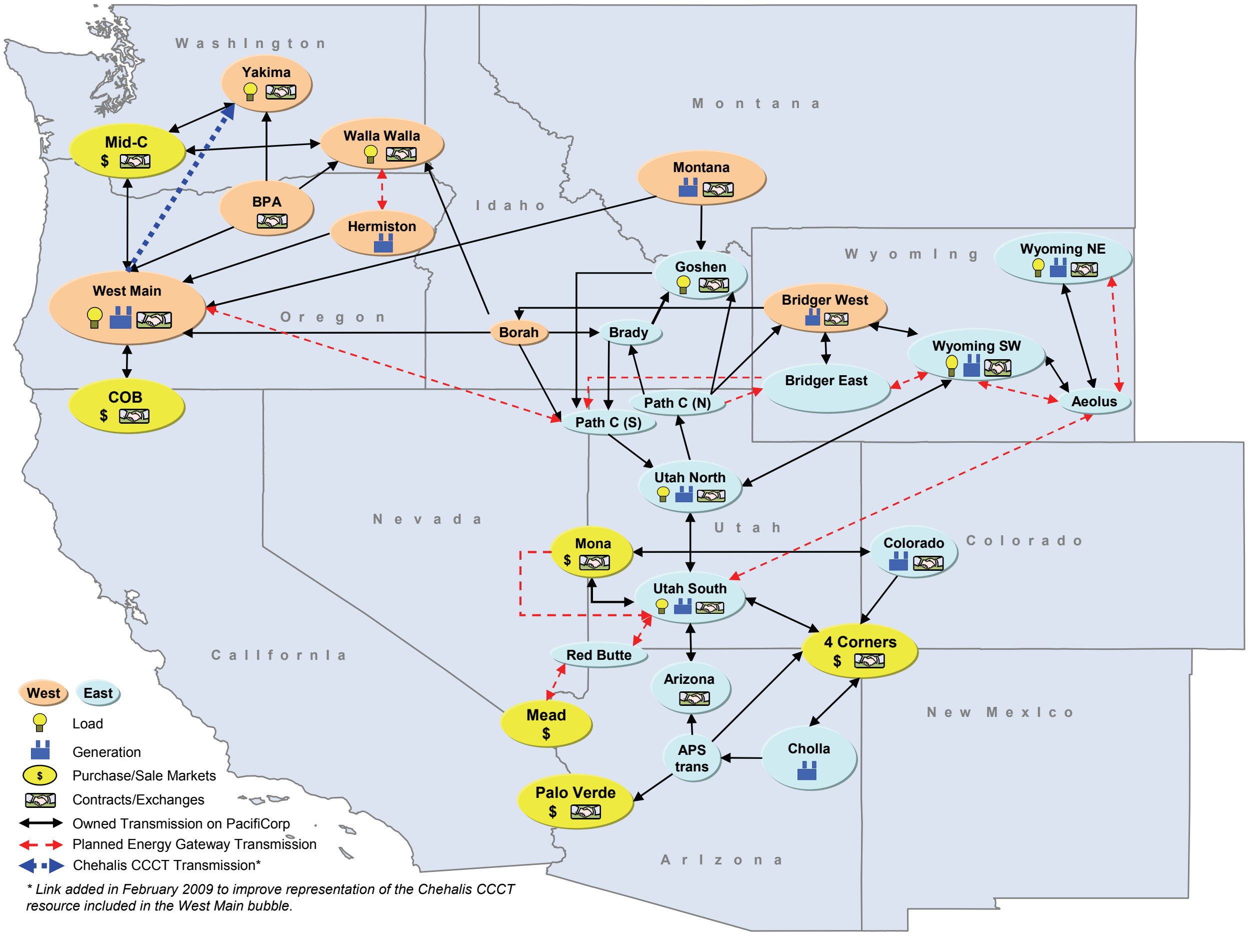
Resource	Book Life (Years)
Supercritical pulverized coal/Integrated Gasification Combined-Cycle	40
Coal plant retrofit with carbon capture and sequestration	20
Combined Cycle Combustion Turbine	40
Pumped Storage	50
Simple Cycle Combustion Turbine (SCCT) Frame	35
Geothermal	40
Solar Photovoltaic	20
Solar Thermal	30
Compressed Air Energy Storage	30
Single Cycle Combustion Turbine (SCCT) Frame	30
Intercooled Aeroderivative SCCT	30
Internal Combustion Engine	30
Fuel Cells	25
Utility-Scale Combined Heat & Power (CHP)	25
Wind	25
Battery Storage	30
Biomass	30
Hydrokinetic, Wave - Floating Buoy	20
Nuclear Plant	40
CHP-Reciprocating Engine	20
CHP - Gas Turbine	20
CHP - Microturbine	15
CHP - Fuel Cell	10
CHP - Commercial Biomass, Anaerobic Digester	15
CHP - Industrial Biomass Waste	15
Solar - Rooftop Photovoltaic	25
Solar - Water Heaters	15
Solar - Attic Fans	10
Dispatchable Standby Generators	20
Recovered Energy Generation	30
Microturbine	15

Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its Eastern Control Area and 10 bubbles in its Western Control Area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant function's current firm rights on the transmission lines. This topology is defined for both the System Optimizer and Planning and Risk models, and was also used for IRP modeling support for PacifiCorp's 2009 business plan.

Figure 7.2 shows the IRP transmission system model topology. Segments of the planned Energy Gateway Transmission Project are indicated with red dashed lines.

Figure 7.2 – Transmission System Model Topology



** Link added in February 2009 to improve representation of the Chehalis CCCT resource included in the West Main bubble.*

The most significant change to the model topology from the one used for the 2007 IRP Update is the expansion of the single Wyoming bubble into three bubbles: Wyoming Southwest, Wyoming Northeast, and Aeolus (substation). This disaggregation supports a more refined view of potential Wyoming resource siting in consideration of transmission constraints—represented as the TOT 4A cut plane—as well as the addition of the planned Aeolus substation that supports Energy Gateway Transmission expansion.

The other major change to the model topology is the addition of the Hermiston bubble in the Western Control Area, which supports the representation of the Walla Walla to McNary segment of the Gateway project.

In February 2009, additional changes were made to the system topology to improve representation of long-term transmission rights for the Chehalis, Washington combined-cycle plant included in the West Main bubble. One of the changes involved the addition of a uni-directional path from the West Main to Yakima bubble. This path addition is shown as a blue dashed line in Figure 7.2. Additionally, the Energy Gateway segment C path (uni-directional, Mona to Oquirrh) was added to facilitate additional market transfer capability from the Mona bubble to Utah South.

CASE DEFINITION

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations in inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values to ensure that a reasonably wide range in potential outcomes is captured.

PacifiCorp defined two types of cases: core cases and sensitivity cases. Core cases focus on broad comparability of portfolio performance results for three key variables. These variables include (1) the level of a per-ton carbon dioxide tax, (2) natural gas and wholesale electricity prices based on PacifiCorp's forward price curves and adjusted as necessary to reflect CO_2 tax impacts, and (3) retail load growth. The Company developed 29 core cases based on a combination of input variable levels.

In contrast, sensitivity cases focus on changes to resource-specific assumptions, alternative CO_2/renewable energy regulatory policies, and planning assumptions. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 17 sensitivity cases reflecting alternative CO_2 compliance strategies, clean base load technology availability, an alternative planning reserve margin level, and inclusion of price-responsive demand-side management programs (Class 3 DSM) as resource options. Also included in the sensitivity case group are two "reference" cases reflecting the 2009 business plan resources for 2009 through 2018, resulting in a total of 19 sensitivity cases.

In developing these cases, PacifiCorp kept to a target range in terms of the total number (40 to 50) in light of the data processing and model run-time requirements involved. To keep the number of cases within this range, PacifiCorp excluded some core cases with improbable combinations of certain input levels, such as a \$100 CO_2 tax and high load growth. (With a high CO_2 tax, a significant amount of demand reduction is expected to occur in the form of conservation, energy efficiency improvements, and utility load control programs.)

PacifiCorp also relied heavily on feedback from public stakeholders. The Company assembled and refined an initial set of cases during April through June 2008, and held three public meetings during May and June to solicit recommendations on their design. The focus of comments was on the number of cases that should be modeled and the appropriateness of the CO_2 tax levels selected. Additional case modifications took place from July through November, reflecting additional stakeholder feedback and input assumption updates made to support the 2009 business plan. For example, PacifiCorp augmented the cases defined with the June 2008 forward price curves as the base forecast with additional ones that used the October price curves. This expansion of cases reflected the desire to account in the IRP analysis the rapid and large price decreases experienced during the last half of 2008.

Case Specifications

Tables 7.2 and 7.3 profile the core and sensitivity/business plan case specifications, respectively. Descriptions of the case variables and explanatory remarks on specific cases follow the tables.

Table 7.2 – Core Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Core Cases										
1	CO2 tax	$0	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
2	CO2 tax	$0	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
3	CO2 tax	$0	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
4	CO2 tax	$45	Low	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
5	CO2 tax	$45	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
6	CO2 tax	$45	Low	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
7	CO2 tax	$45	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
8	CO2 tax	$45	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
9	CO2 tax	$45	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
10	CO2 tax	$45	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
11	CO2 tax	$45	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
12	CO2 tax	$45	Medium	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
13	CO2 tax	$45	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
14	CO2 tax	$45	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
15	CO2 tax	$45	High	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
16	CO2 tax	$70	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
17	CO2 tax	$70	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
18	CO2 tax	$70	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
19	CO2 tax	$70	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
20	CO2 tax	$70	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
21	CO2 tax	$70	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
22	CO2 tax	$70	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
23	CO2 tax	$100	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
24	CO2 tax	$100	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
25	CO2 tax	$100	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
26	CO2 tax	$100	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
27	CO2 tax	$100	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
28	CO2 tax	$100	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
29	CO2 tax	$100	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded

Table 7.3 – Sensitivity and Business Plan Reference Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Real CO2 Cost Escalation with Changing Load Growth										
30	CO2 tax	$45 (2013) to $163 (2028)	Medium	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
31	CO2 tax	$45 (2013) to $163 (2028)	High	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
National CO2 Cap-and-Trade Policy: Lieberman-Warner "Climate Security Act of 2008" (SB 3036, introduced May 20, 2008)										
32	Cap-and-Trade	Market	Medium	Oct-08	Medium	Base	Base	Base	12%	Excluded
High-Cost Outcome										
33	CO2 tax	$100	High	Jun-08	High	Base	Late	High	12%	Excluded
Clean Base-Load Generation Availability										
34	CO2 tax	$45	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
35	CO2 tax	$45	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
36	CO2 tax	$70	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
37	CO2 tax	$70	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
High Plant Construction Costs										
38	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	High	12%	Excluded
39	CO2 tax	$45	High	Jun-08	Medium	Base	Base	High	12%	Excluded
Oregon CO2 Reduction Targets (from HB 3543) Applied as System-wide Hard Caps										
40	Hard Cap	N/A	Medium	Jun-08	Medium	Base	Base	Base	12%	Excluded
Alternative Planning Reserve Margin Level (15%)										
41	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
42	CO2 tax	$70	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
43	CO2 tax	$100	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
Alternative renewable policy assumptions										
44	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	High	Base	Base	12%	Excluded
45	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Base/PTC expires	Base	Base	12%	Excluded
Business Plan Reference Cases										
46	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Fixed RPS-compliant wind schedule	Base	Base	12%	Excluded
47	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Optimized RPS-compliant renewables	Base	Base	12%	Excluded
Class 3 DSM For Peak Load Reduction										
48	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	12%	Included

Carbon Dioxide Compliance Strategy and Costs

Given that no single CO_2 reduction compliance approach has emerged as a consistent front-runner for adoption, the long-term planning effort undertaken through this IRP considers a wide range of carbon cost outcomes that are assessed as a direct tax on emissions (each short ton of CO_2 emitted). As mentioned above, a CO_2 tax is modeled for all the core cases. The CO_2 tax has an assumed 2013 implementation date, and increases at PacifiCorp's assumed inflation rate.

The tax is treated as a variable cost in both the System Optimizer and PaR models. In System Optimizer, the tax is accounted for in both resource investment decisions as well as the model dispatch solution. For the PaR model, the tax is accounted for in the model's unit commitment/dispatch solution.

The core cases have been specified with four tax levels: no tax, \$45/ton, \$70/ton, and \$100/ton. The \$0 tax serves to create reference portfolios from which the incremental cost of CO_2 regulations can be determined. The \$45 tax represents a reasonable intermediate value and starting point at which significant changes in resource mix over the long term can be expected to occur. This value—along with the \$70 value—are also in line with the Electric Power Research Institute's finding that for its reference CO_2 price impact modeling case for western electricity markets, "...it takes a CO_2 price of roughly \$50/ton to flatten the growth of emissions over time, and closer to \$70/ton to effect a significant reduction over time."[36] The \$100 tax then reflects a reasonable high-end value associated with an aggressive Federal emission reduction policy.

For sensitivity cases 30 and 31, PacifiCorp developed a CO_2 tax trajectory with a real cost escalation, and also assumed that the associated demand response would result in a lower load growth trend beginning in 2021. The CO_2 tax values for these cases are shown in Table 7.4.

Table 7.4 – CO_2 Tax Values

Year	CO2 Tax Level, 2008 Dollars per Ton			
	\$45	**\$70**	**\$100**	**\$45, Real Escalation**
2013	49.44	\$76.91	\$109.87	45.00
2014	50.33	\$78.29	\$111.84	52.86
2015	51.29	\$79.78	\$113.97	60.71
2016	52.31	\$81.37	\$116.25	68.57
2017	53.36	\$83.00	\$118.57	76.43
2018	54.43	\$84.66	\$120.95	84.29
2019	55.51	\$86.36	\$123.36	92.14
2020	56.62	\$88.08	\$125.83	100.00
2021	57.70	\$89.76	\$128.22	107.86
2022	58.80	\$91.46	\$130.66	115.71
2023	59.91	\$93.20	\$133.14	123.57
2024	61.05	\$94.97	\$135.67	131.43
2025	62.15	\$96.68	\$138.11	139.29
2026	63.27	\$98.42	\$140.60	147.14
2027	64.47	\$100.29	\$143.27	155.00
2028	65.70	\$102.19	\$145.99	162.86

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[36] Electric Power Research Institute, Slide Presentation, Collaborative EPRI Analysis of CO_2 Price Impacts on Western Power Markets, page 18, June 2008.

For sensitivity case 32, The CO_2 costs are in the form of allowance market prices resulting from implementation of a federal cap-and-trade program such as the Lieberman-Warner Climate Security Act of 2008. (This proposed legislation specified a final CO_2 emissions target of 71 percent below 2005 levels in 2050.) Due to the complexity of developing the inputs for this sensitivity case, PacifiCorp did not have time to perform this analysis before this IRP was prepared. PacifiCorp will make the results available to IRP stakeholders once the study has been completed.

Sensitivity case 40 assumes that PacifiCorp is subject to a system-wide hard CO_2 cap. A hard cap is a physical emission limit that cannot be exceeded, and is typically expressed as a declining annual value. This sensitivity case is intended to support the following Public Utility Commission of Oregon's 2007 IRP acknowledgment order requirement:

> For the 2007 IRP update and next planning cycle, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.[37]

Oregon's HB 3543 targets are to achieve greenhouse gas emission levels 10 percent below 1990 levels by 2020, and by 2050, achieve reductions of a least 75 percent below 1990 levels. With a 2012 emissions base of 56.1 million tons, these targets translate into 41.4 million tons by 2020 and 33.4 million tons by 2028. Because PacifiCorp plans on a system basis, and its IRP models are not currently capable of representing Oregon-only emission constraints in the context of such system planning, Oregon's hard cap is applied on a system level.

The CO_2 compliance strategy and cost assumptions for sensitivity cases 46 and 47 reflect those used for PacifiCorp's 2009 business plan, which is based on a Federal cap-and-trade compliance mechanism. Cap-and-trade assumptions include the following:

- Emissions peaking in 2012 (56.1 million tons) and declining to 2007 emission levels (56.5 million tons by 2025), assuming straight-line annual decreases for modeling purposes
- Straight-line annual emissions decreasing to 1990 levels by 2030
- An initial CO_2 allowance price of $8.79/ton starting in 2013 (in 2008 dollars), and increasing at PacifiCorp's annual inflation rates
- No auctioning or banking of allowances

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[37] Public Utility Commission of Oregon, Order No. 08-232, Docket LC 42, April 24, 2008, p. 36.

Table 7.5 – CO_2 Prices for the Business Plan Reference Cases

Year	CO2 Price 2008 Dollars per Ton
2013	8.79
2014	8.95
2015	9.12
2016	9.30
2017	9.49
2018	9.68
2019	9.87
2020	10.07
2021	10.26
2022	10.45
2023	10.65
2024	10.85
2025	11.05
2026	11.25
2027	11.46
2028	11.68

Natural Gas and Electricity Prices

Due to the strong correlation between natural gas and wholesale electricity prices, these variables were linked together as low, medium, or high values for a case. Two sets of gas/electricity price scenario values were used for defining cases. The June 2008 forward price curves served as the initial base forecast for IRP modeling support for the 2009 business plan and development of IRP scenario price curves reflecting CO_2 price responses. Due to the large decline in gas prices following the spring/summer spike, PacifiCorp adopted the October 2008 forward price curves for the final business plan modeling, and incorporated these forecasts as additional cases in the IRP (cases 9, 10, 11, 18, 19, 20, 25, 26, and 27). The price forecasting methodology and resulting scenario price forecasts are presented later in this chapter.

Retail Load Growth

The low and high load growth forecasts reflect a respective one-percentage-point average annual growth rate decrease and increase relative to the growth rate for the medium (1-in-2) forecast. For cases 30 and 31, PacifiCorp combined the medium forecast for 2009 to 2020, and the low forecast for 2021 to 2028, using a smoothing algorithm to determine the data elements around the breakpoint. Figures 7.3 and 7.4 show the annual peak load and energy forecast values used for the case definitions.

Figure 7.3 – Peak Load Growth Scenarios

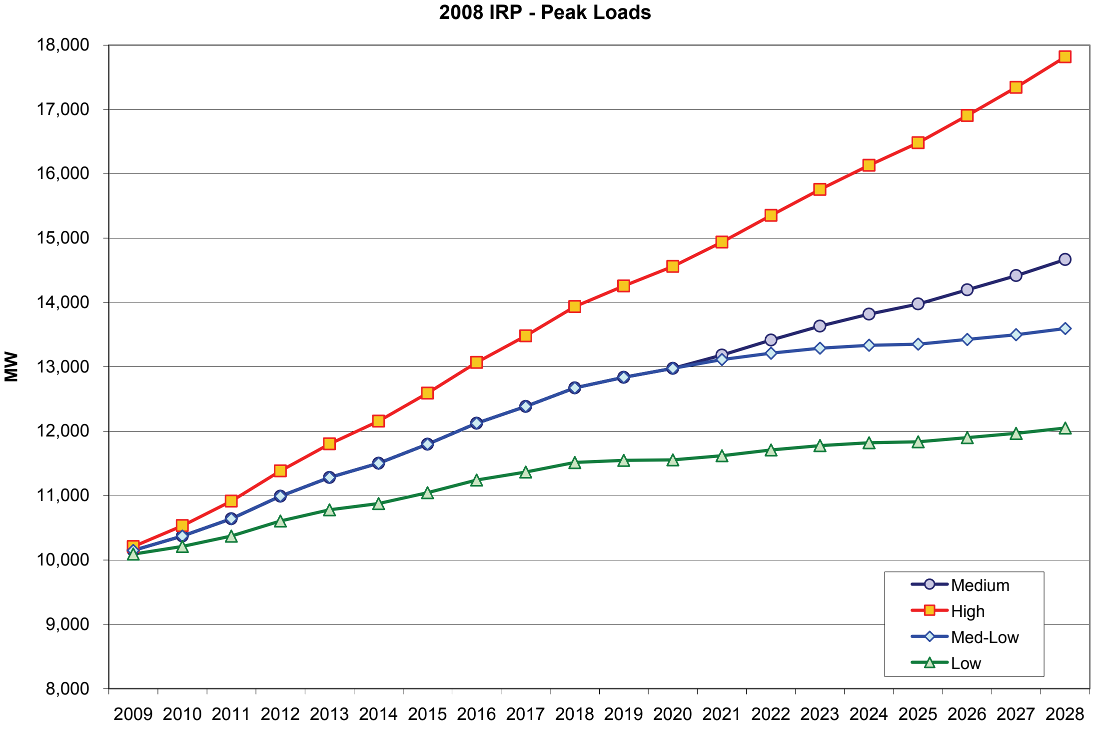
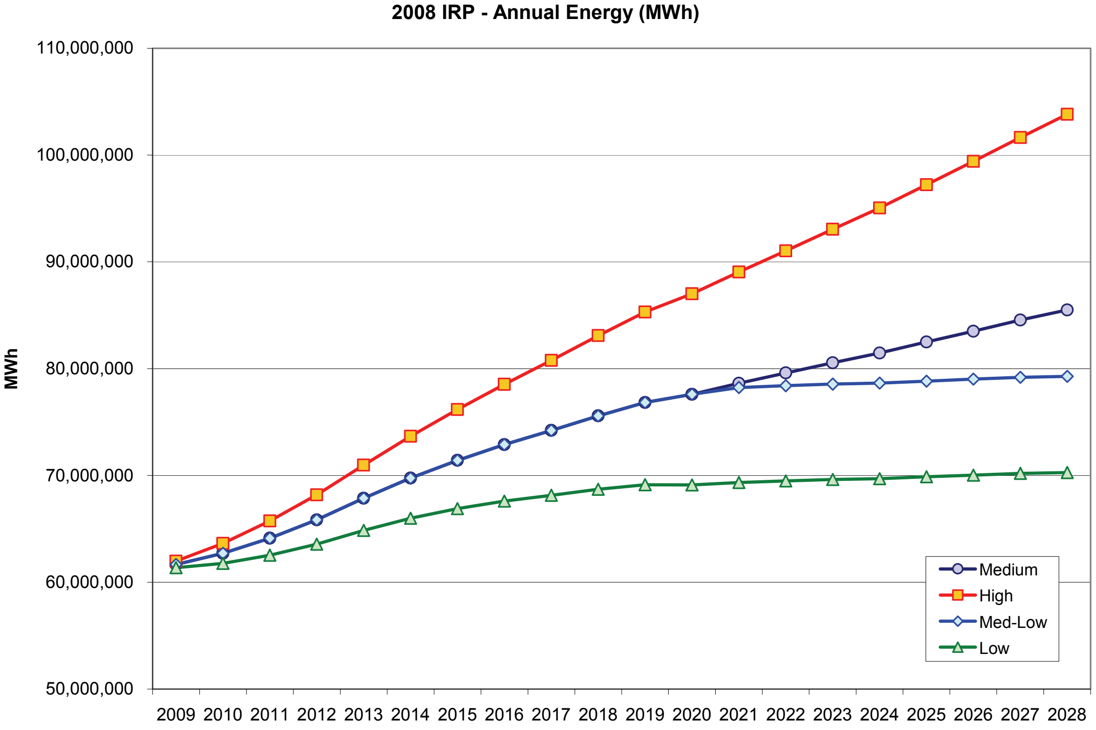


Figure 7.4 – Energy Load Growth Scenarios



Renewable Portfolio Standards

In addition to the base renewable portfolio standards modeled, sensitivity case 44 tests a scenario for which the renewable generation requirement is higher, reflecting imposition of a Federal standard or more aggressive state standards. (Modeling of renewable portfolio standards is discussed in the section on optimized portfolio development.)

For the high RPS generation requirement, PacifiCorp assumed that the current Revised Protocol under the Multi-state Process remains in place, requiring the Company to acquire sufficient system resources to meet Oregon's cost allocation share based on their RPS targets. This assumption translates into a 25-percent RPS generation requirement with respect to the forecasted system load by 2026.

Renewables Production Tax Credit Expiration

Sensitivity case 45 is intended to study how the loss of the PTC affects the timing and magnitude of renewable resource additions. For this sensitivity, the renewables PTC is assumed to fully expire in 2013.

Clean Base Load Plant Availability

Sensitivity cases 34 through 37 evaluate whether clean base load plants—IGCC and new/existing pulverized coal plant retrofits with carbon capture and sequestration—are cost-effective enough to build as early as 2020 given the $45/ton and $70/ton CO_2 tax levels and variation in gas prices. The assumed earliest availability for these plants is 2025.

High Plant Construction Costs

Sensitivity cases 38 and 39 are intended to determine the resource selection impact of increasing capital costs for all resources by 20 percent above their base values under medium and high gas price conditions. Capital-intensive resources will be disadvantaged under this assumption, so these sensitivities test the extent that such resources are deferred or eliminated from portfolios despite higher gas prices.

Capacity Planning Reserve Margin

Cases 41 42, and 43 are intended for development of portfolios built to meet or exceed a 15-percent capacity planning reserve margin. The resulting portfolios are compared with their counterpart portfolios built to a 12-percent planning reserve margin (cases 8, 17, and 24). These comparisons are intended to determine the resource mix impact of higher CO2 tax levels.

Business Plan Reference Cases

Cases 46 and 47 represent portfolios that have the major 2009 business plan resources fixed in the model. They were optimized with business plan assumptions, including the $8/ton cap-and-trade program assumptions and October 2008 price forecasts. System Optimizer was allowed to select DSM and distributed generation resources up to 2018, and allowed to select any resource from 2019 onward subject to the annual quantity constraints outlined in Chapter 6. (Business plan resources only cover the period 2009 through 2018.) The difference between the two cases is that the renewable resources were fixed in case 46 for 2009-2018—reflecting the wind acquisition schedule determined by PacifiCorp's wind development team for the business plan[38]—whereas for case 47, the model was allowed to optimize the amount and timing of renewables subject to the annual quantity constraints.

Class 3 Demand-side Management Programs for Peak Load Reductions

For sensitivity case 48, System Optimizer is allowed to select price-responsive DSM programs. These programs, outlined in Chapter 6, include real-time pricing (for commercial and industrial customers), demand buyback, curtailment, and critical peak pricing.

SCENARIO PRICE FORECAST DEVELOPMENT

On a central tendency basis, commodity markets tend to respond to the evolution of supply and demand fundamentals over time. Due to a complex web of cross-commodity interactions, price movements in response to supply and demand fundamentals for one commodity can have implications for the supply and demand dynamics and price of other commodities. This interaction routinely occurs in markets common to the electric sector as evidenced by a strong positive correlation between natural gas prices and electricity prices.

Some relationships among commodity prices have a long historical record that have been studied extensively, and consequently, are often forecasted to persist with reasonable confidence. However, robust forecasting techniques are required to capture the effects of secondary or even tertiary conditions that have historically supported such cross-commodity relationships. For example, the strong correlation between natural gas prices and electricity prices is intrinsically tied to the increased use of natural gas-fired capacity to produce electricity. If for some reason in the future natural gas-fired capacity diminishes in favor of an alternative technology, the linkage between gas prices and electricity prices would almost certainly weaken.

PacifiCorp deploys a variety of forecasting tools and methods to capture cross-commodity interactions when projecting prices for those markets most critical to this IRP – natural gas prices, electricity prices, and emission prices. Figure 7.5 depicts a simplified representation of the framework used by PacifiCorp to develop the price forecasts for these different commodities. At the highest level, the commodity price forecast approach begins at a global scale with an assessment of natural gas market fundamentals. This global assessment of the natural gas market yields a price forecast that feeds into a national model where the influence of emission and renewable energy policies is captured. Finally, outcomes from the national model feed into a regional model where the up-stream gas prices and emission prices drive a forecast of wholesale electricity prices. In this fashion, we are able to produce an internally consistent set of price forecasts across a range of potential future outcomes at the pricing points that interface with PacifiCorp's system.

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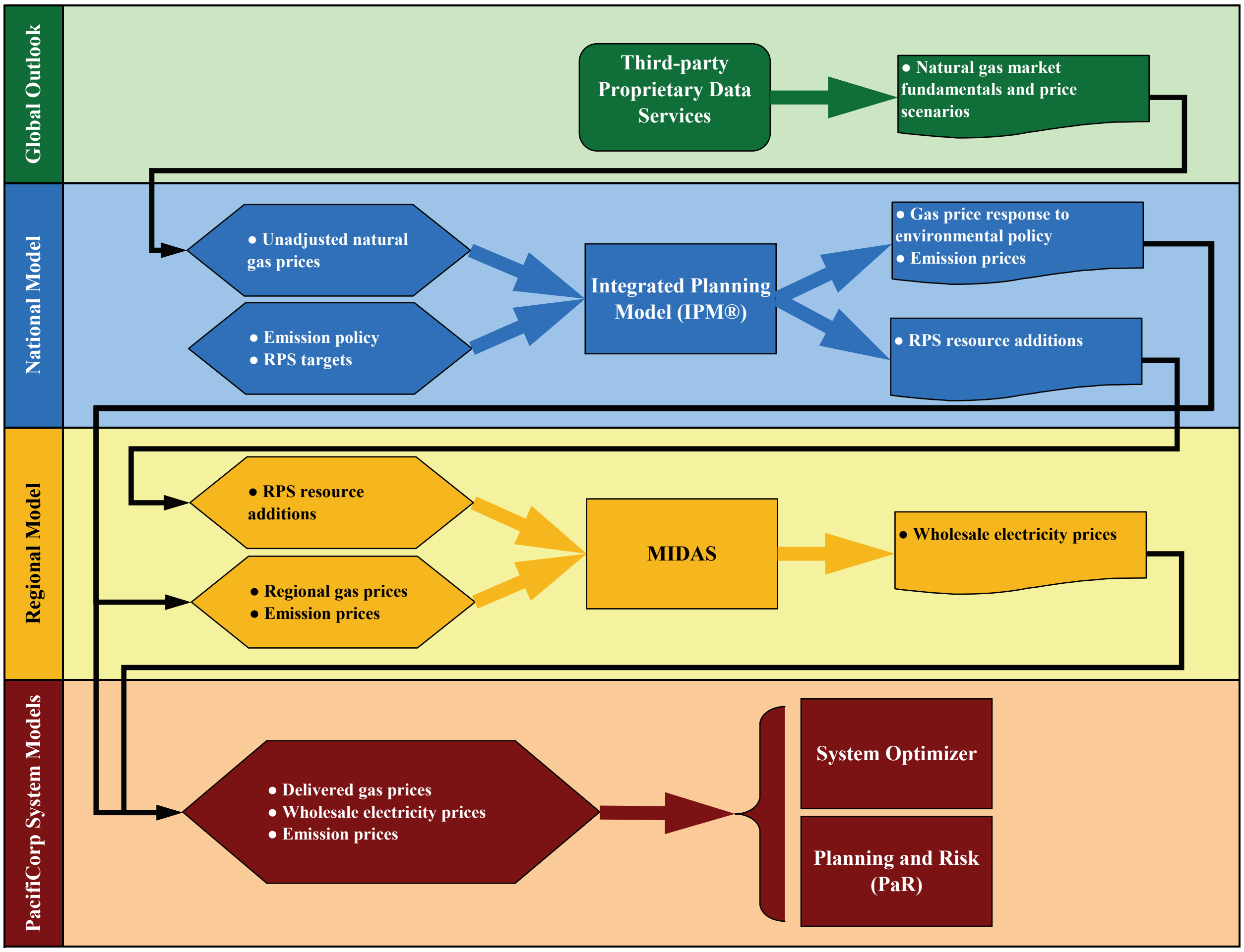
[38] This wind acquisition schedule reflects an assessment of RPS requirements, capital budget impacts, current and prospective commercial opportunities, transmission constraints and expansion considerations (i.e., the Energy Gateway Transmission Project), operational and system integration issues, locational diversity, state procurement rules, and the MEHC renewables acquisition commitment.

Figure 7.5 – Modeling Framework for Commodity Price Forecasts



The process begins with an assessment of global gas market fundamentals and an associated forecast of North American natural gas prices. In this step, PacifiCorp relies upon a number of third-party proprietary data and forecasting services to establish a range of gas price scenarios. Each price scenario reflects a specific view of how the North American natural gas market will balance supply and demand. Given the emergence of liquefied natural gas (LNG) in the global marketplace, the linkage of global gas prices to global oil prices, and the potential need for LNG imports to balance supply with domestic demand, any price forecast for the North American market requires a view of global fundamentals.

Once a natural gas price forecast is established, the integrated planning model (IPM®) is used to simulate the entire North American power system. IPM®, a linear program, determines the least cost means of meeting electric energy and capacity requirements over time, and in its quest to lower costs, ensures that all assumed emission policies and renewable portfolio standard (RPS) policies are met. Concurrently, IPM® can be configured with a dynamic natural gas price supply curve that allows natural gas prices to respond to changes in demand triggered by environmental compliance. Additional outputs from IPM® include a forecast of resource additions consistent with all specified RPS targets, electric energy and capacity prices, coal prices, electric sector fuel consumption, and emission prices for policies administered in a cap-and-trade framework.

Once emission prices and the associated gas price response are forecasted with IPM®, results are used in a regional model named Midas, to produce an accompanying wholesales electricity price forecast. Midas is an hourly chronological dispatch model configured to simulate the Western Interconnection and offers a more refined representation of western wholesale electricity markets than is possible with IPM®. Consequently, we are able to produce a more granular price projection that covers all of the markets required for the PacifiCorp system models used in the IRP. The gas, wholesale electricity, and emission price forecasts developed under this framework and used in the cases for this IRP are summarized in the sections that follow.

Gas and Electricity Price Forecasts

A total of five underlying natural gas price forecasts are used to develop the 28 unique gas price projections for the cases analyzed in this IRP. A range of fundamental assumptions affecting how the North American market will balance supply and demand defines the five underlying price forecasts. Table 7.6 shows representative prices at the Henry Hub benchmark for the five underlying natural gas price forecasts. The five forecasts serve as a point of reference and are adjusted to account for changes in natural gas demand driven by a range of environmental policy and technology assumptions specific to each IRP case.

Table 7.6 – Underlying Henry Hub Price Forecast Summary (nominal $/MMBtu)

Forecast Name	2010	2015	2020	2025	2030
High - June 2008	$18.06	$18.71	$21.21	$23.28	$25.55
High - October 2008	$11.57	$14.68	$19.98	$21.93	$24.07
Medium - June 2008	$11.23	$9.90	$12.31	$13.51	$14.83
Medium - October 2008	$7.83	$8.58	$11.07	$12.85	$14.11
Low - June 2008[39]	$5.83	$6.29	$7.09	$7.78	$8.54

Price Projections Tied to the High June 2008 Forecast

The underlying June 2008 high gas price forecast is defined by high oil prices and low LNG imports, reduced production from mature natural gas fields, disappointments in new production from frontier gas fields, and policies that hold back new coal and nuclear additions, which supports electric sector natural gas demand despite high prices. Figure 7.6 summarizes prices at the Henry Hub benchmark and Figure 7.7 summarizes the accompanying electricity prices for the forecasts developed around the high June 2008 gas price projection.

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[39] This underlying forecast serves as the reference case for development of the “low - October 2008” price forecast scenario.

Figure 7.6 – Henry Hub Natural Gas Prices from the High June 2008 Underlying Forecast

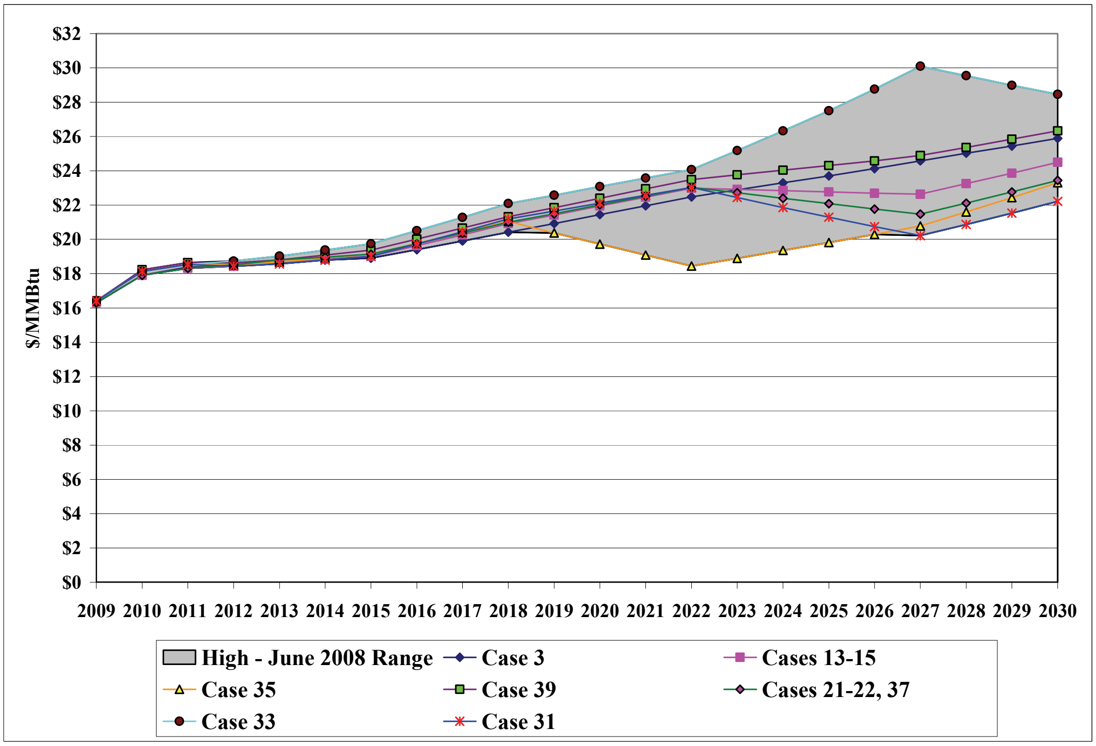
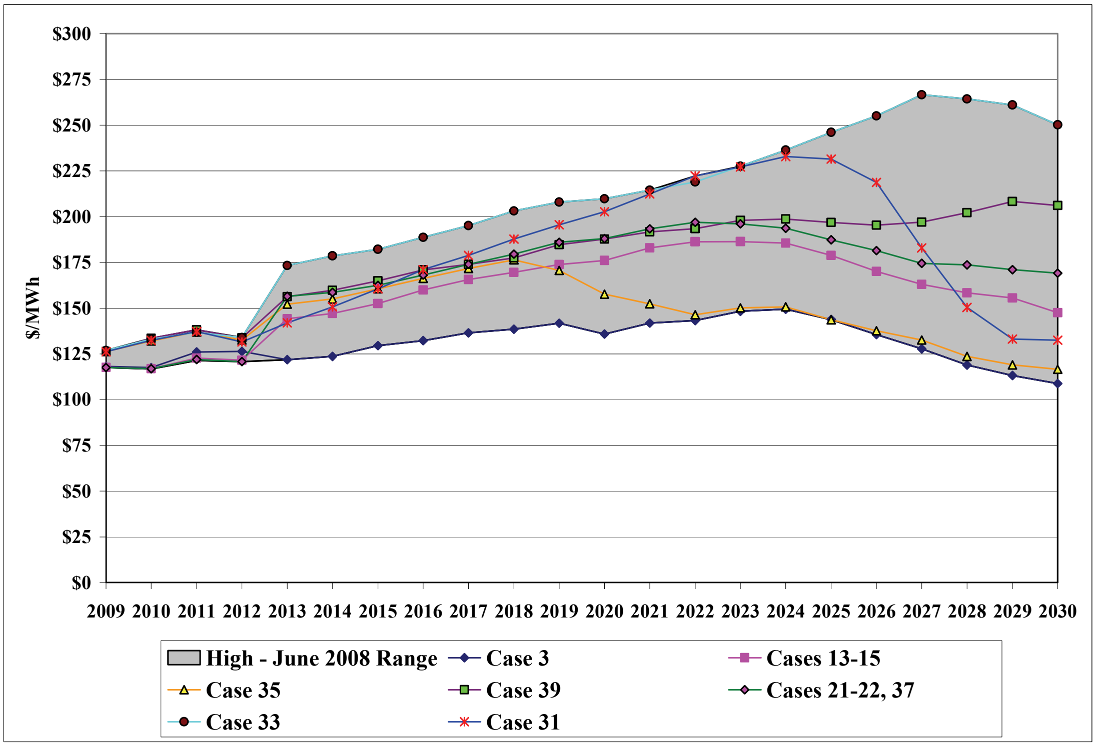


Figure 7.7 – Western Electricity Prices from the High June 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the High October 2008 Forecast

A second high gas price forecast was added in October 2008 in response to economic developments, which lowers the near-term price trajectory in response to lagging demand. Longer-term, the October 2008 high gas price forecast is lower than the June 2008 forecast due to a more optimistic outlook for domestic unconventional natural gas production. Figure 7.8 depicts Henry Hub benchmark prices and Figure 7.9 summarizes the accompanying electricity prices for the forecasts developed around the high October 2008 gas price projection.

Figure 7.8 – Henry Hub Natural Gas Prices from the High October 2008 Underlying Forecast

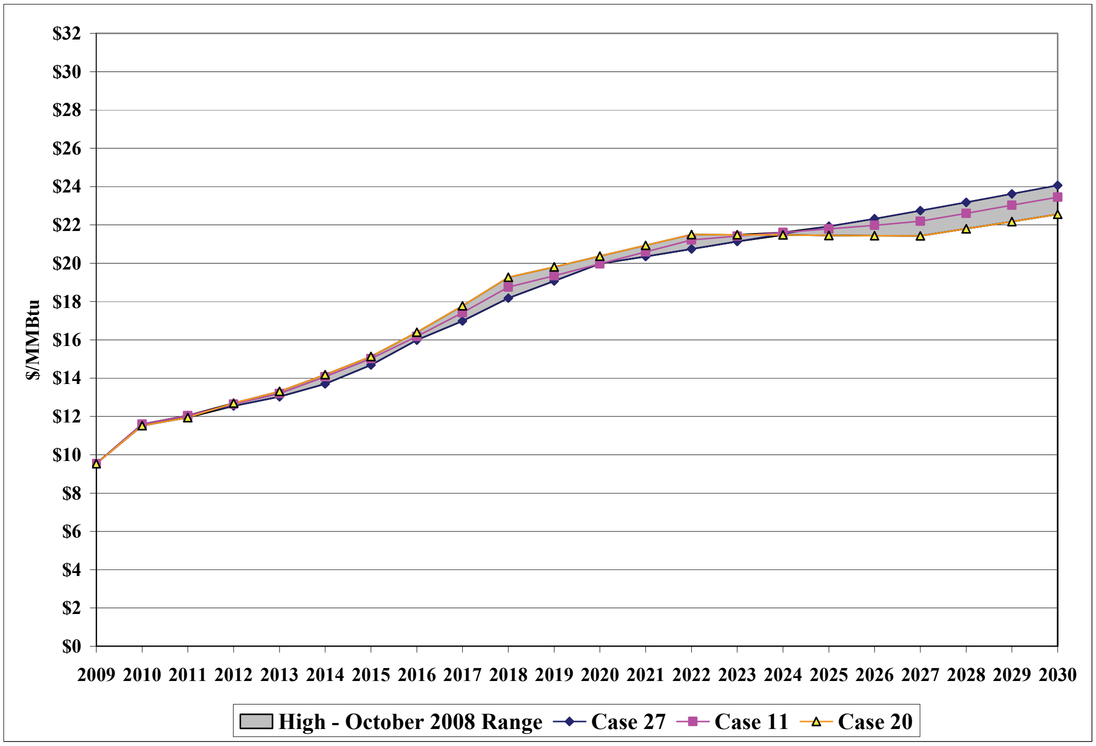
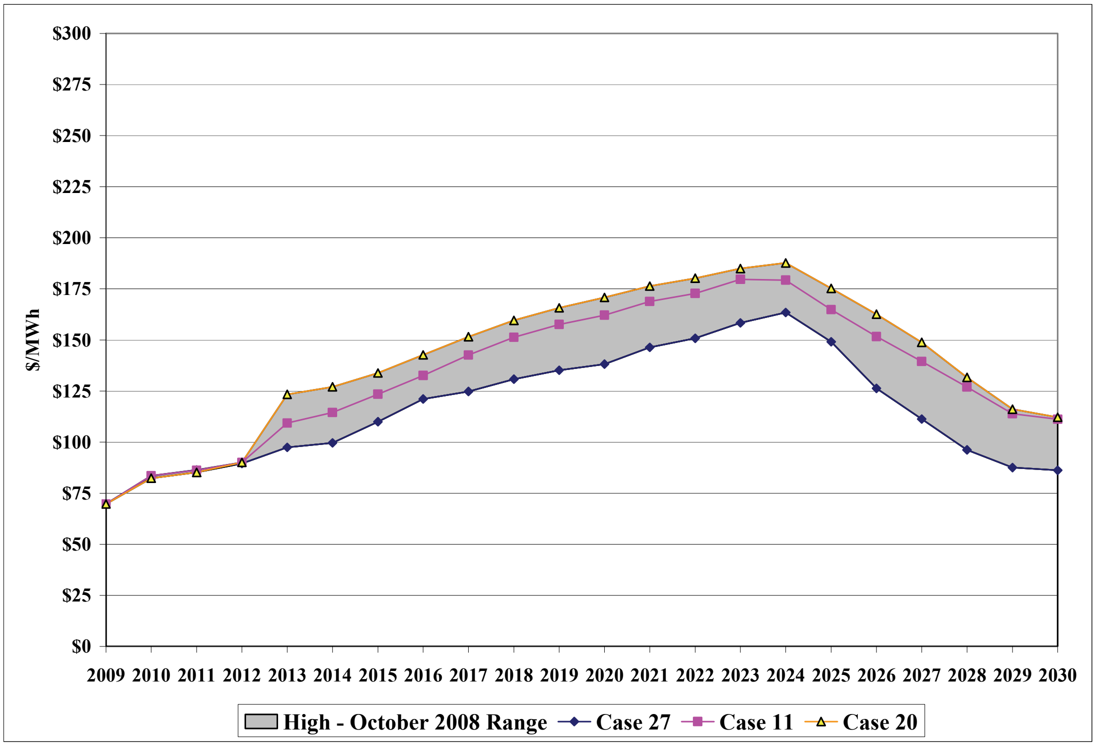


Figure 7.9 – Western Electricity Prices from the High October 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Medium June 2008 Forecast

The underlying June 2008 medium gas price forecast relies upon market forwards for the first six years and a fundamentals-based projection thereafter. For the market portion of the forecast, prices are based upon forwards as of market close on June 30, 2008. The fundamentals-based part of the forecast depicts a future in which declining LNG imports coincide with strong demand from the electric sector driven by resistance to new coal-fired and nuclear capacity. It is assumed that unconventional production will largely be able to keep pace with growing demand, but production costs are projected to be higher than what has been exhibited in the recent expansion of unconventional fields in the Rocky Mountain region and in the Barnett Shale formation. Further, global oil prices are anticipated to remain much higher than historical averages. As with the high price forecasts, a second medium price forecast was added in October 2008 in response to economic developments. Figure 7.10 shows Henry Hub benchmark prices and Figure 7.11 includes the accompanying electricity prices for the forecasts developed around the medium June 2008 gas price projection.

Figure 7.10 – Henry Hub Natural Gas Prices from the Medium June 2008 Underlying Forecast

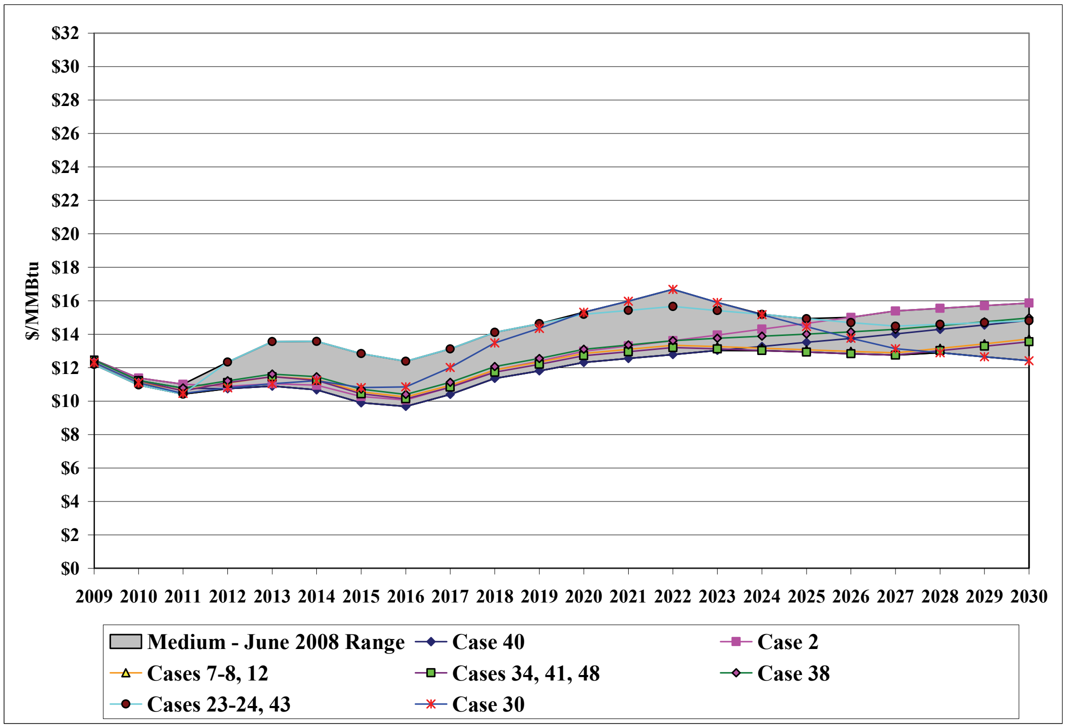
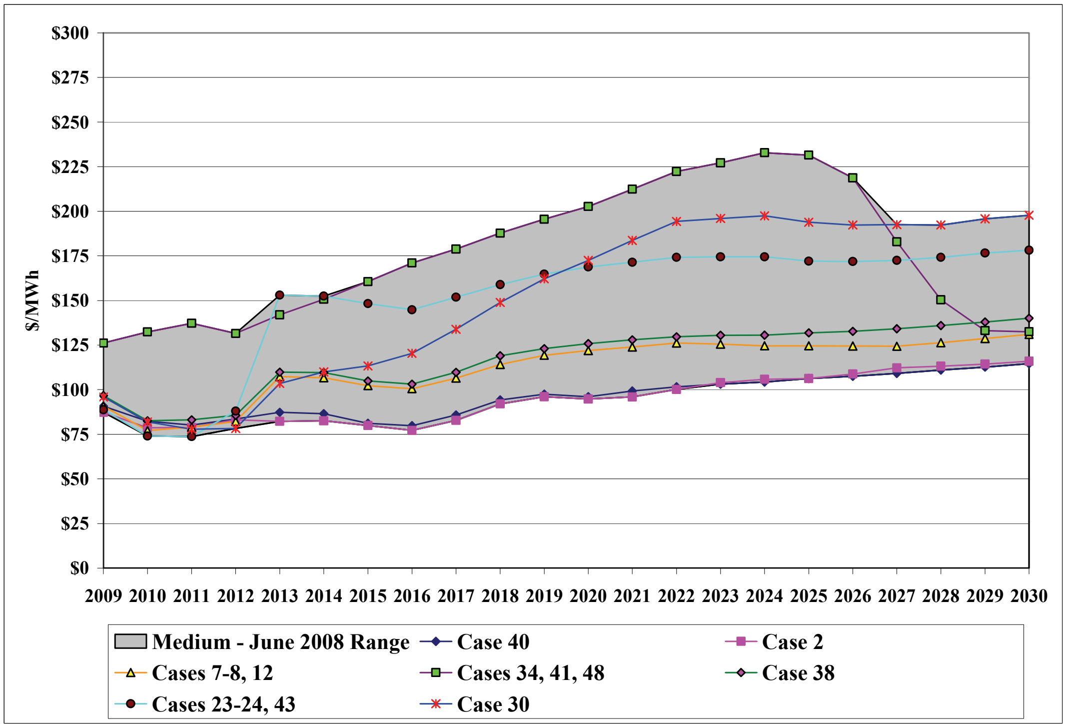


Figure 7.11 – Western Electricity Prices from the Medium June 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Medium October 2008 Forecast

As with the high price forecasts, a second underlying medium gas price forecast was added in October 2008 in response to economic developments. In this second medium price forecast, the market portion of the curve is replaced with forwards as of market close on October 20, 2008. The longer-term forecast is slightly lower than the June 2008 medium forecast, which reflects a lower long-term oil price outlook and a more optimistic view of new supply out of Alaska. Figure 7.12 shows Henry Hub benchmark prices and Figure 7.13 includes the accompanying electricity prices for the forecasts developed around the medium October 2008 gas price projection.

Figure 7.12 – Henry Hub Natural Gas Prices from the Medium October 2008 Underlying Forecast

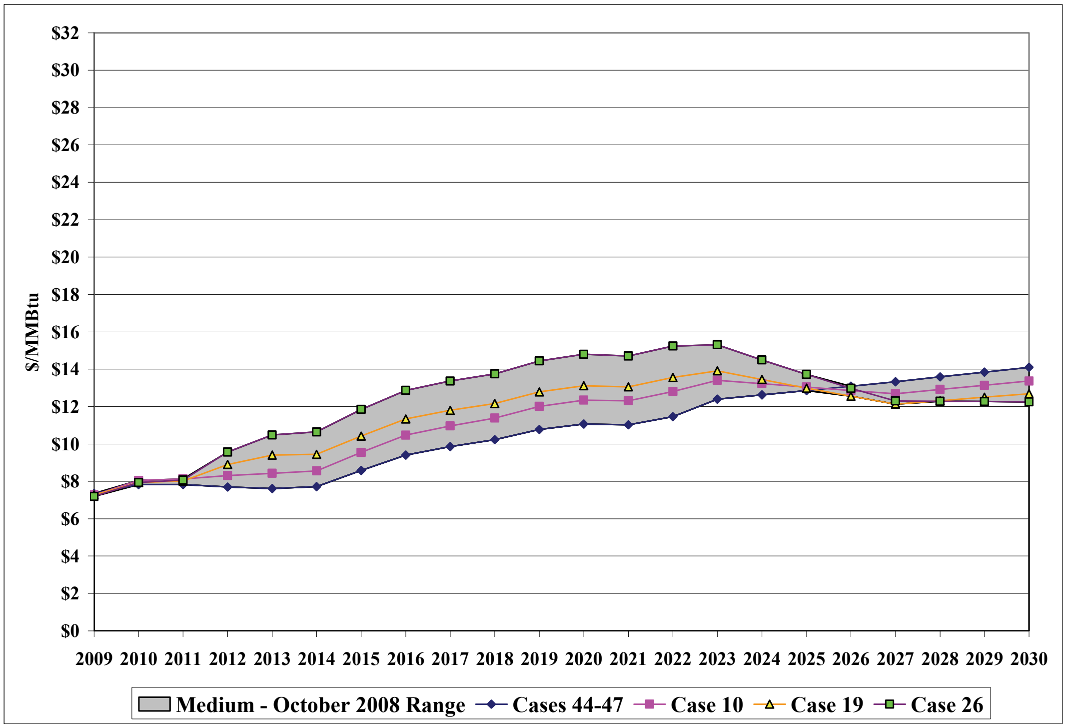
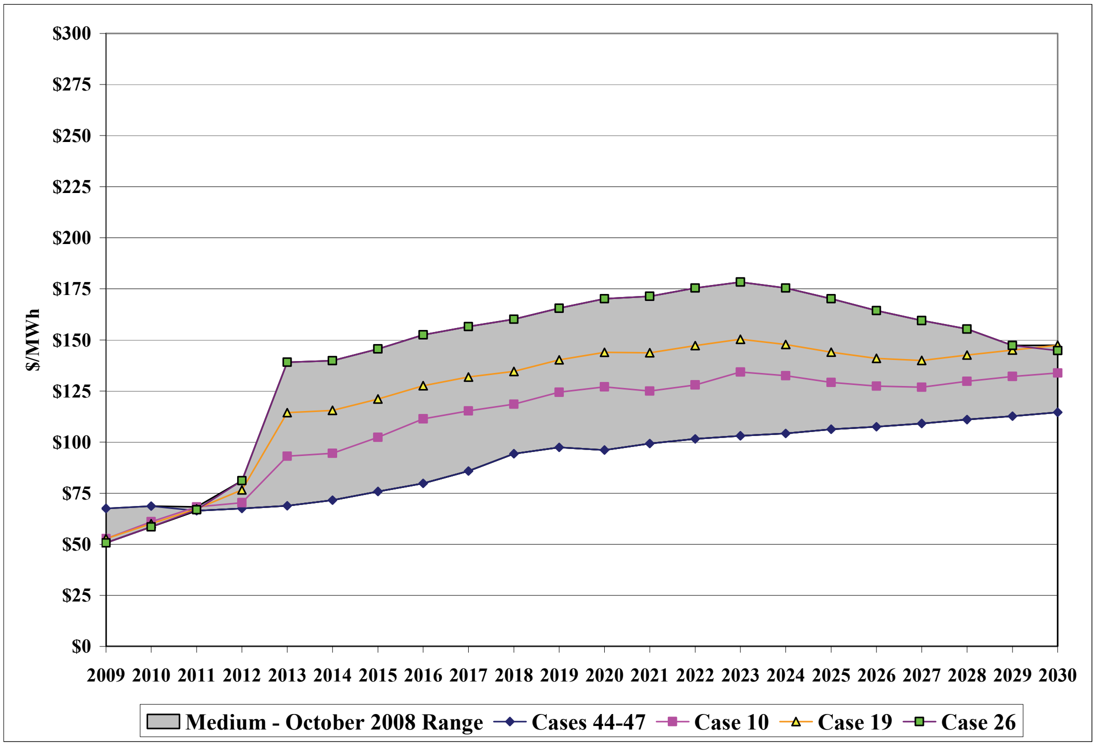


Figure 7.13 – Western Electricity Prices from the Medium June 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Price Projections Tied to the Low June 2008 Forecast

The underlying June 2008 low gas price forecast is defined by low oil prices and an extended period of growth from unconventional natural gas fields. Through this period of growth in unconventional production, it is assumed that knowledge transfer and technological advancements keep production costs on the decline. Concurrently, global LNG projects continue to come online while Asian markets experience growth in pipeline gas from China and India. Consequently, despite strong domestic growth from unconventional gas fields, LNG imports are diverted to the North American market. On the demand front, recent gas price spikes steer new power plant development away from gas-fired capacity, thereby keeping demand from the electric sector at bay. Given that the low price forecast is already defined by suppressed demand and an optimistic outlook for low cost supply, a second low price forecast was not added in October 2008. Figure 7.14 shows Henry Hub benchmark prices and Figure 7.15 includes the accompanying electricity prices for the forecasts developed around the low June 2008 gas price projection.

Figure 7.14 – Henry Hub Natural Gas Prices from the Low June 2008 Underlying Forecast

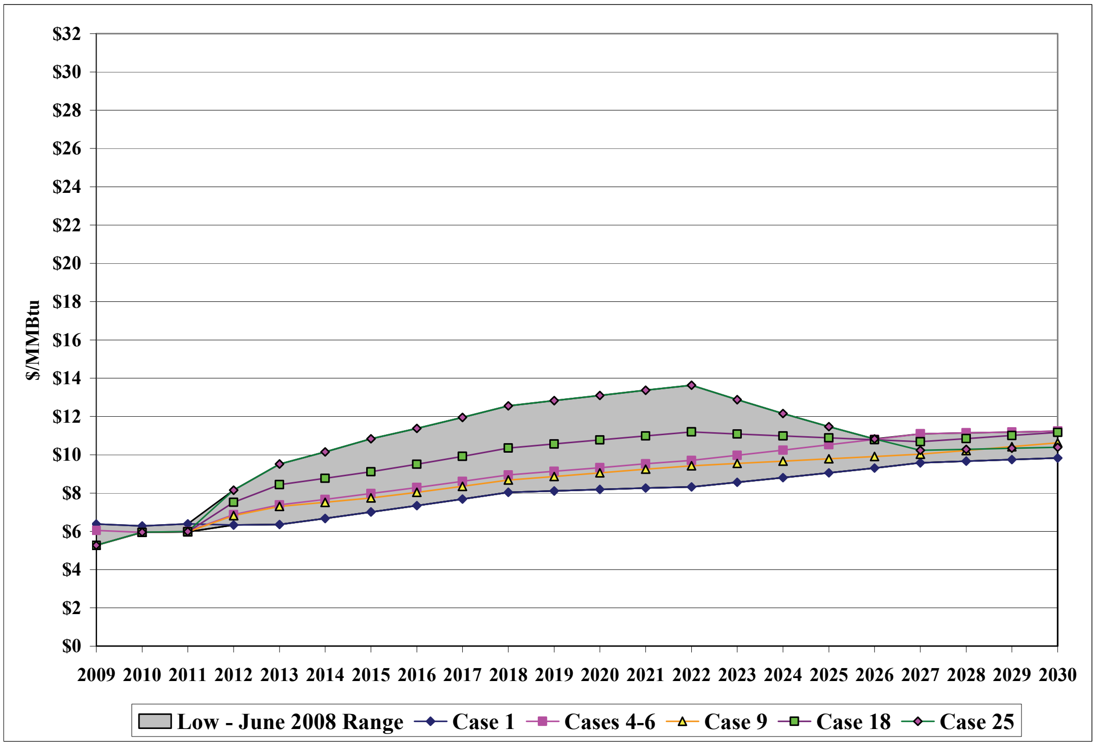
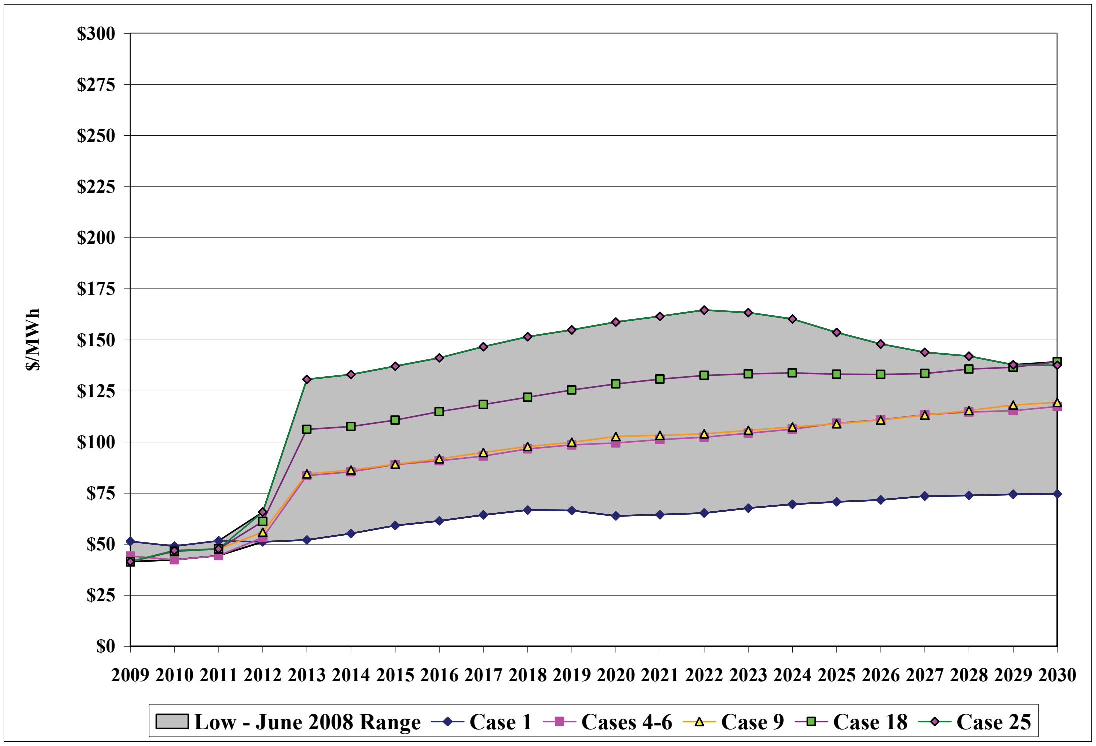


Figure 7.15 – Western Electricity Prices from the Low June 2008 Underlying Gas Price Forecast



[1] Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Emission Price Forecasts

As events unfolded in 2008, it became increasingly clear that policy uncertainty is not reserved only for greenhouse gas emissions. In February 2008, the D.C. Circuit Court of Appeals vacated the Clean Air Mercury Rule (CAMR) on the grounds that it was illegal for the Environmental Protection Agency (EPA) to de-list mercury as a hazardous pollutant. With this ruling, it became evident that a CAMR-based trading program for mercury allowances would not be implemented, and consequently, mercury allowance price forecasts are not studied in this IRP. Nonetheless, across all cases evaluated, it is assumed that all coal-fired supply side resource options are outfitted with activated carbon injection control technologies. (All fossil fuel plants are assigned a mercury emission rate, and mercury emissions for each portfolio are reported in Chapter 8.)

As with mercury, events in 2008 also introduced increased uncertainty to the sulfur dioxide (SO_2) allowance market. In July 2008, the D.C. Circuit Court of Appeals vacated the Clean Air Interstate Rule (CAIR) citing several fatal flaws and remanded it back to EPA with direction to promulgate a new rule. Once CAIR was vacated, the value of existing SO_2 allowances, which could be used for future CAIR compliance needs, dropped overnight and prices fell precipitously. The market continued to function, albeit at light trading volumes and at prices detached from long-term fundamentals.

EPA petitioned the court for rehearing in September 2008, and the court asked petitioners from the case to file briefs stating their opinion on EPA's request. In December 2008, the court reversed its previous finding and remanded the rule back to EPA without vacating the rule in its entirety. In its December decision, the court explained that its vacatur would sacrifice clear benefits to public health and the environment while EPA fixes the rule. While the latest court ruling reinstates CAIR, it only does so until EPA can promulgate a new rule that addresses the problems identified in the original finding or until legislative action is taken. Consequently, prices for existing SO_2 allowance prices remain below the likely cost of future compliance.

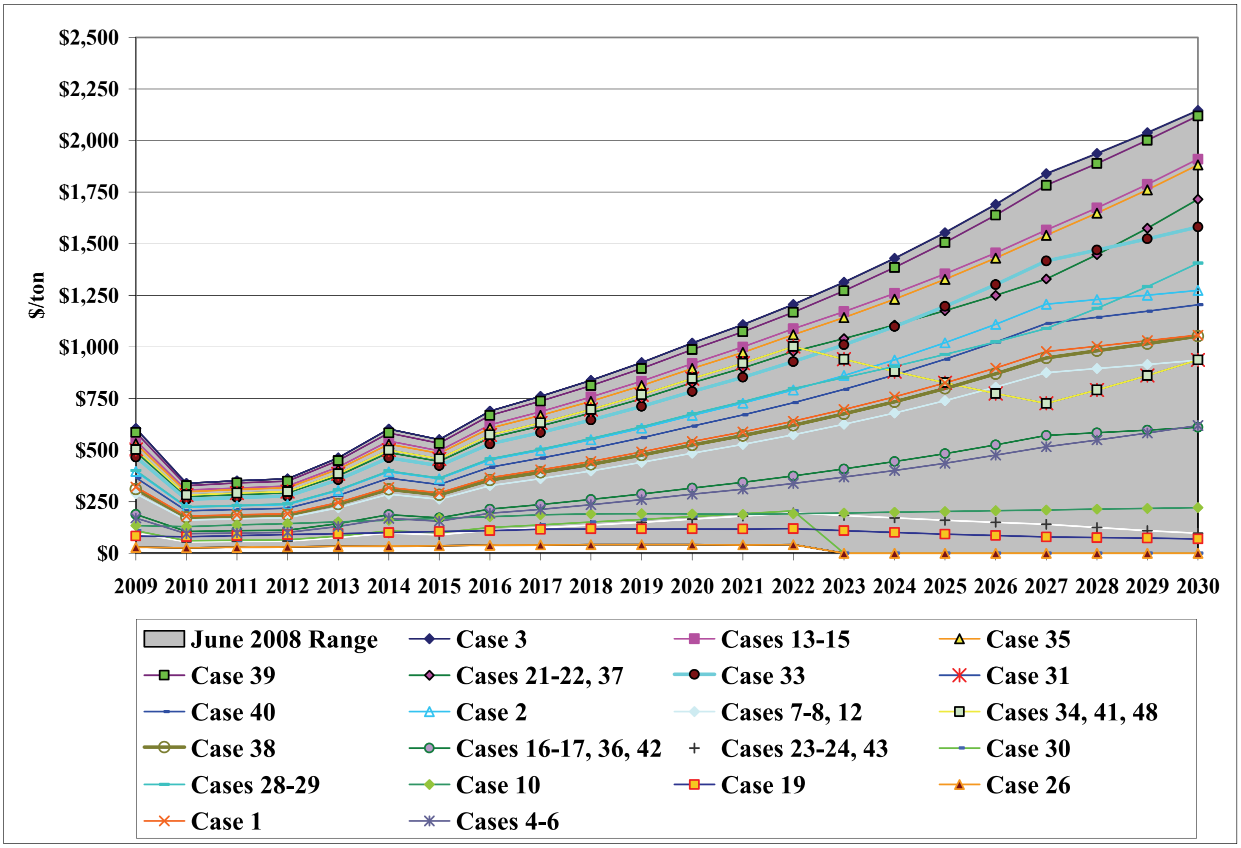
Given the tremendous uncertainty in the SO_2 allowance market and considering that current prices have departed from a fundamentals-view of future compliance costs, two sets of reference SO_2 allowance price forecasts were developed for this IRP. The two reference SO_2 allowance price forecasts are adjusted in response to the specific variables for any given case in much the same way that the underlying gas price forecasts are adjusted. As case variables are changed, IPM® is used to produce an associated SO_2 allowance price response, which in turn is used to make adjustments to the appropriate reference price forecasts. Table 7.7 summarizes SO_2 allowance prices developed for the two reference forecasts.

Table 7.7 – Reference SO_2 Allowance Price Forecast Summary (nominal $/ton)

Forecast Name	2010	2015	2020	2025	2030
June 2008	$205	$333	$616	$940	$1,204
August 2008	$157	$206	$232	$247	$271

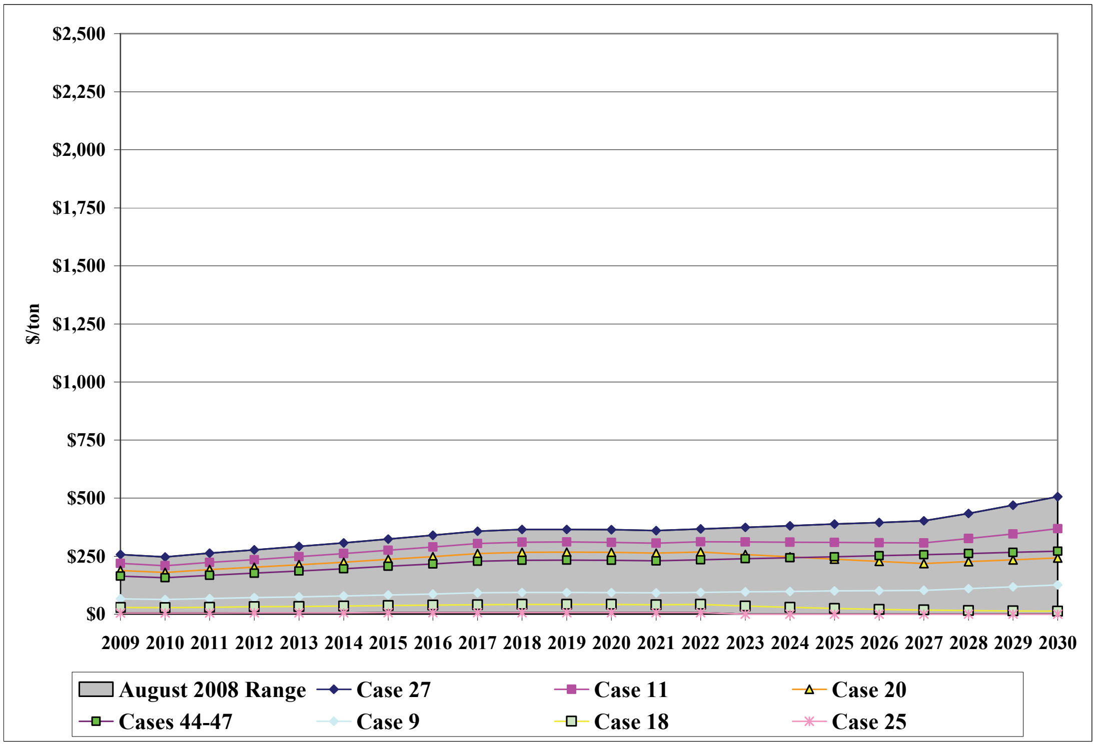
The June 2008 reference forecast reflects a combination of market forwards and a fundamentals-based price forecast. The market portion of the forecast extends through 2012 and reflects forwards as of June 20, 2008. Prices from 2013 through 2015 are derived as a gradual transition from the market forwards to the subsequent fundamentals-based forecast, which is applied starting in 2016. The fundamentals-based forecast is indicative of future compliance costs tied to the marginal cost of installing scrubbers on enough units to achieve the emission reduction targets established under CAIR. Figure 7.16 shows SO_2 allowance prices for the forecasts developed around the June 2008 reference price projection.

Figure 7.16 – SO_2 Allowance Prices Developed off of the June 2008 Reference Forecast



The August 2008 reference SO_2 allowance price forecast is based almost entirely upon market forwards as of August 7, 2008. The market is used for prices through 2021 and escalated at inflation thereafter. Under this reference price forecast, it is assumed that the uncertainties plaguing the SO_2 allowance market will continue into the foreseeable future. Figure 7.17 shows SO_2 allowance prices for the forecasts developed around the August 2008 reference price projection.

Figure 7.17 – SO_2 Allowance Prices Developed off of the August 2008 Reference Forecast



OPTIMIZED PORTFOLIO DEVELOPMENT

For Phase 3, the System Optimizer is executed for each set of case assumptions, generating an optimized investment plan and associated real levelized present value of revenue requirements (PVRR) for 2009 through 2028. System Optimizer operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the 20-year study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for each load area represented in the model).

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

For capital cost derivation, System Optimizer uses annual capital recovery factors to address end-effects issues associated with capital-intensive investments of different durations and in-service dates. PacifiCorp used the real-levelized capital costs produced by the System Optimizer for portfolio cost reporting by the PaR model.

Representation and Modeling of Renewable Portfolio Standards

PacifiCorp incorporates annual system-wide renewable generation constraints in the System Optimizer model to ensure that each optimized portfolio meets state Renewable Portfolio Standard (RPS) requirements.[40] For the base case RPS requirement, current Oregon, Utah, Washington, and California rules are followed. The resulting system generation requirement, using the state end-use energy forecasts as the starting point, reaches two percent of system load for 2011-2014, five percent for 2015-2019, six percent for 2020-2024, and 15 percent for 2025-2028. A key assumption backing the system-wide RPS representation is that all of PacifiCorp's state jurisdictions will adopt renewable energy credit (REC) trading rules through the Multi-state Process, thus enabling sales and purchase of surplus banked RECs.

RPS modeling is conducted as a two-step process. First, for each case the System Optimizer generates a portfolio without any RPS constraints applied. Determining whether the portfolio meets the RPS constraints is an off-line exercise utilizing a spreadsheet accounting model. The main components of the model include for each applicable state (1) the annual RPS requirement, (2) the annual generation from qualifying existing renewable facilities and resources selected by the System Optimizer, and (3) tracking of annual cumulative surplus REC bank balances. The qualifying generation for the all states, divided by the system load, represents the RPS compliance percentage. If this compliance percentage falls short of the generation requirement for a given year, available surplus banked RECs are applied. A portfolio is RPS-compliant if the RPS compliance percentage exceeds the RPS generation requirement for all years.

For step two, if the portfolio is not RPS-compliant then PacifiCorp re-runs the System Optimizer model with the annual RPS constraints turned on. To the extent the RPS requirement is not met, the model will add eligible resources to ensure compliance. Comparison of the costs for the RPS non-compliant and compliant portfolios indicates the incremental cost of RPS compliance with additional renewable resources.[41]

For each case, an RPS compliance report was generated. This report shows the annual system RPS requirements, REC bank balances, REC-adjusted qualifying generation, RPS compliance percentages, and the system load used in the calculations. The report also includes a line chart comparing the RPS compliance and system generation requirements percentages for both the base and high RPS scenarios. The RPS compliance reports are included in Appendix A.

Modeling Front Office Transactions and Growth Resources

Front office transactions, described in Chapter 6, are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization model-

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[40] The model currently is designed to treat RPS constraints as a generation percentage of system load. PacifiCorp is working with the model vendor on enhancements that enable representation of load-based RPS requirements for multiple jurisdictions.

[41] This two-step approach is intended to address a Utah commission 2007 IRP acknowledgment order requirement.

ing, System Optimizer engages in market purchase acquisition—both front office transactions, and for hourly energy balancing, spot market purchases—to the extent it is economic given other available resources. The model can select virtually any quantity of FOT generation up to limits imposed for each case, in any study year, independently of choices in other years. However, once a front office transaction resource is selected, it is treated as a must-run resource for the duration of the transaction period. For this IRP, front office transactions are available for all years in the study period. (In contrast, front office transactions were only modeled through 2018 in the 2007 IRP, after which the model could select only growth resources to meet load growth.)

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

Another resource type included in the IRP models is the *growth resource*. This resource is intended for capacity balancing in each load area to ensure that capacity reserve margins are met in the out years of each simulation (after 2020). The System Optimizer model can select an annual flat or third-quarter heavy load hour energy pattern priced at forward market prices appropriate for each load area. Growth resources are similar to front office transactions, except that they are not transacted at market hubs.

Modeling Wind Resources

Wind resources are modeled with an hourly generation shape that reflects average hourly wind variability. The shapes are scaled to capacity factors reflecting representative wind resource qualities across PacifiCorp's system. (See Chapter 6 for more details on wind resource options.) The hourly generation shape is repeated for each year of the simulation, and is used in both the System Optimizer and Planning and Risk models.

Because System Optimizer is not a detailed chronological unit commitment and dispatch model, the cost impacts of wind tied to unit commitment are not captured. Also, system costs and reliability effects associated with intra-hour wind variability are not captured.

To capture the costs of integrating wind into the system, PacifiCorp applied a value of \$11.75/MWh (in 2008 dollars) for portfolio modeling. The source of this value was Portland General Electric Company's wind integration study, which assumed penetration of over 1,000 MW of wind capacity with no addition of supporting flexible thermal resources. This value was selected as a reasonable proxy to use until PacifiCorp's own wind integration cost study is completed.

To reflect realistic system resource addition limits tied to transmission availability and other factors such as resource market availability and procurement constraints, System Optimizer was constrained to select up to 500 MW per year of wind prior to 2014, and 750 MW per year in 2014 and thereafter.

Modeling Fossil Fuel Efficiency Improvements

For all IRP modeling, PacifiCorp used forward-looking heat rates for existing fossil fuel plants, which account for plant efficiency improvement plans. Previously the Company used four-year historical average heat rates. This change ensures that such planned improvements are factored in the optimized portfolios and stochastic production cost simulations, in line with the goals of the PURPA fossil fuel generation efficiency standard that is part of the 2005 Energy Policy Act.

MONTE CARLO PRODUCTION COST SIMULATION

Phase 4 entails simulation of each optimized portfolios from Phase 3 using the Planning and Risk model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. Three stochastic simulations were executed for the three CO_2 tax levels: \$0/ton, \$45/ton, and \$100/ton. These levels reflect a reasonable middle value along with bookends adopted for portfolio development. All the simulations used the October 2008 forward price curves as the expected gas and electricity price forecast values. This maintains comparability with the price forecast assumptions used for the 2009 business plan, as well as with the business plan reference cases, numbers 46 and 47.

The PaR simulation also incorporates stochastic risk in its production cost estimates by using a stochastic model and Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability for new resources. (For existing thermal units, planned maintenance schedules were used.[42]) Although wind resource generation was not varied in the same way as the other stochastic variables, the hour-to-hour generation does vary throughout the year, but the pattern is repeated identically for all study years (2009-2028) and Monte Carlo iterations.

The Stochastic Model

The stochastic model used in PaR is a two-factor (a short-run and a long-run factor) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand.

Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to market prices, the long-run factor should be understood as an expected equilibrium, with the Monte Carlo draws defining a possible forward equilibrium state. In the case of regional electricity loads, the Monte Carlo draws define possible forward paths for electricity demand.

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[42] Stochastic simulation of existing thermal unit availability is undesirable because it introduces cost variability unassociated with the evaluation of new resources, which confounds comparative portfolio analysis.

Stochastic Model Parameter Estimation

Stochastic model parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The econometric analysis uses 48 months of historical data for parameter estimation.

The long-run parameters are derived from a "random-walk with drift" regression. The standard error of the random-walk regression defines the long-run volatility for the regional electricity load variables. In the case of the natural gas and electricity market prices, the standard error of the random walk regression is interpolated with the volatilities from the Company's official forward price curves over the twenty-year IRP study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets, as well as the impacts from changes in expected regional electricity loads.

PacifiCorp's econometric analysis is performed for the following stochastic variables:

- Fuel prices (natural gas prices for the Company's western and eastern control areas),
- Electricity market prices for Mid-Columbia (Mid C), California – Oregon Border (COB), Four Corners, and Palo Verde (PV),
- Electric transmission area loads (California, Idaho, Oregon, Utah, Washington and Wyoming regions)
- Hydroelectric generation

For outage modeling, PacifiCorp relies on the PaR model's Monte Carlo simulation method to create a distributed outage pattern for new resources. PacifiCorp does not estimate stochastic parameters for plant outages.

Monte Carlo Simulation

During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are of percentage deviations from the expected forward value of the variables, and are the same for each Monte Carlo simulation. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

The PaR model is configured to conduct 100 Monte Carlo simulation runs for the 20-year study period, so that each of the 100 simulations has its own set of stochastic parameters and shocked forecast values. The end result of the Monte Carlo simulation is 100 production cost runs (iterations) reflecting a wide range of portfolio cost outcomes.

Figures 7.18 through 7.21 show the 100-iteration frequencies for market prices resulting from the Monte Carlo draws for two representative years, 2009 and 2018. Figures 7.22 through 7.26 show the annual loads by load area at different percentiles: 10th, 25th, 50th, 75th, and 90th. Figure 7.27 shows the 25th, 50th, and 75th percentiles for hydroelectric generation.

Figure 7.18 – Frequency of Western (Mid-Columbia) Electricity Market Prices for 2009 and 2018

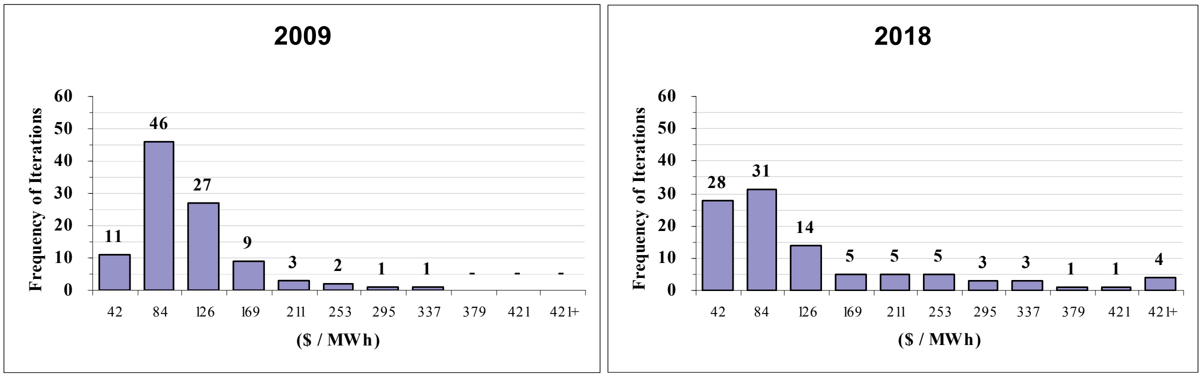


Figure 7.19 – Frequency of Eastern (Palo Verde) Electricity Market Prices, 2009 and 2018

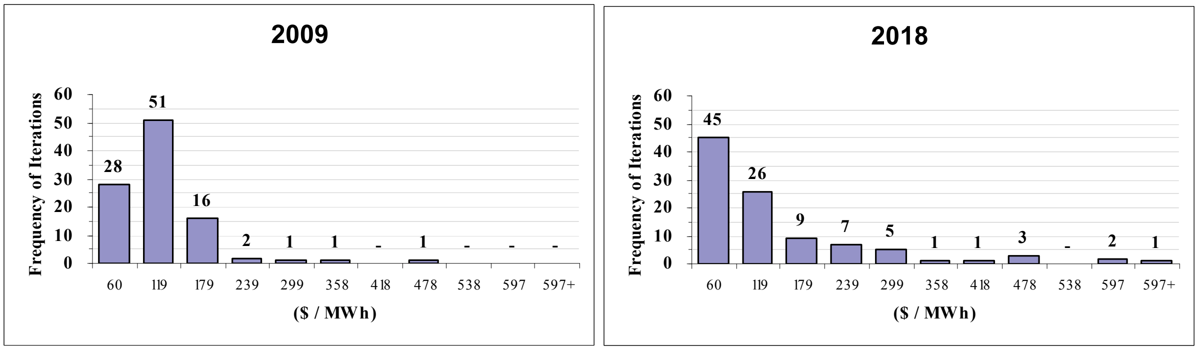


Figure 7.20 – Frequency of Western Natural Gas Market Prices, 2009 and 2018

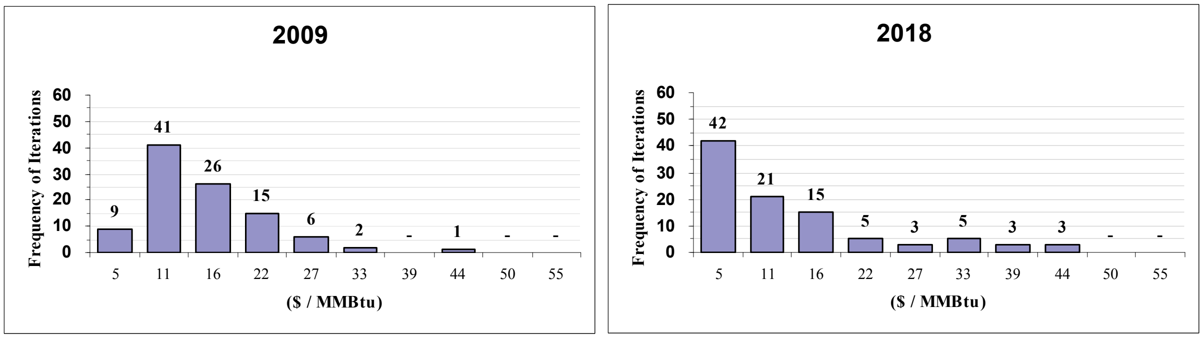


Figure 7.21 – Frequency of Eastern Natural Gas Market Prices, 2009 and 2018

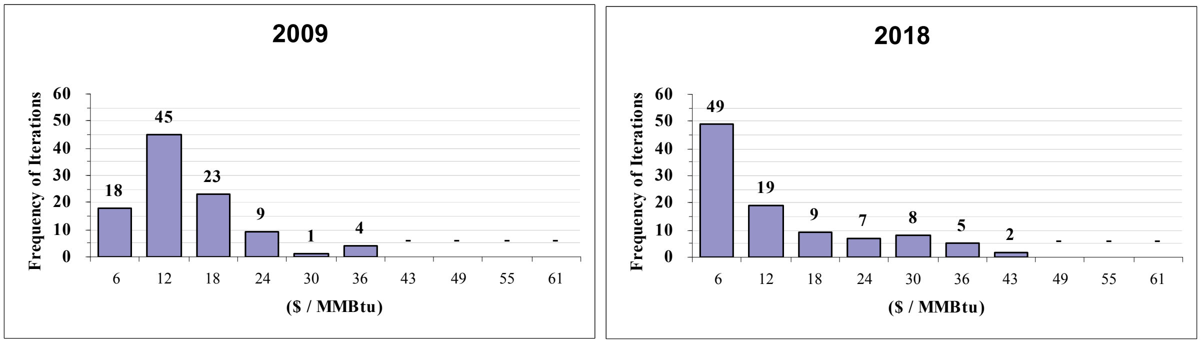


Figure 7.22 – Frequencies for Idaho (Goshen) Loads

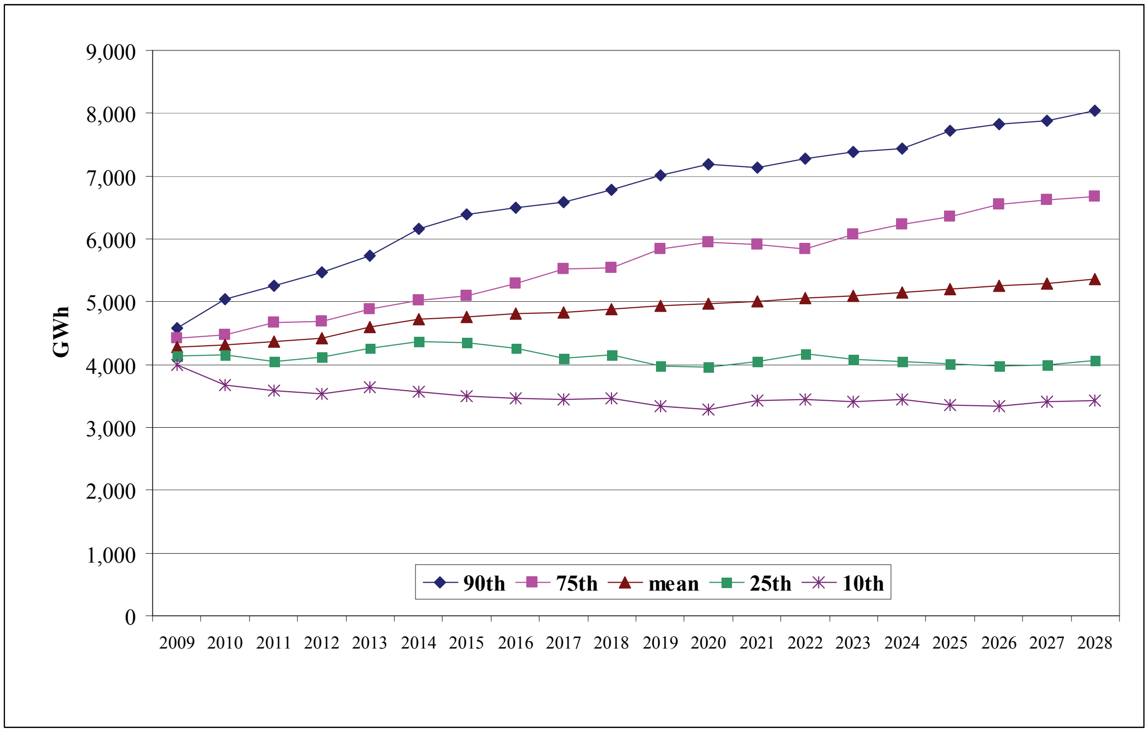


Figure 7.23 – Frequencies for Utah Loads

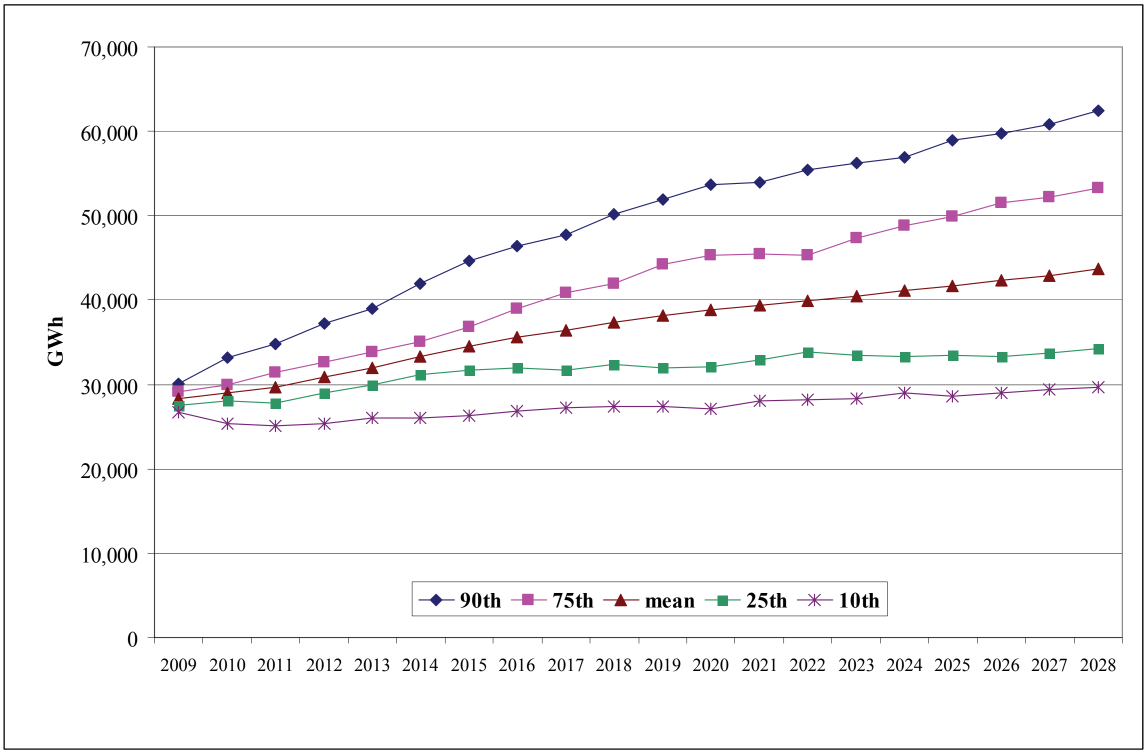


Figure 7.24 – Frequencies for Washington Loads

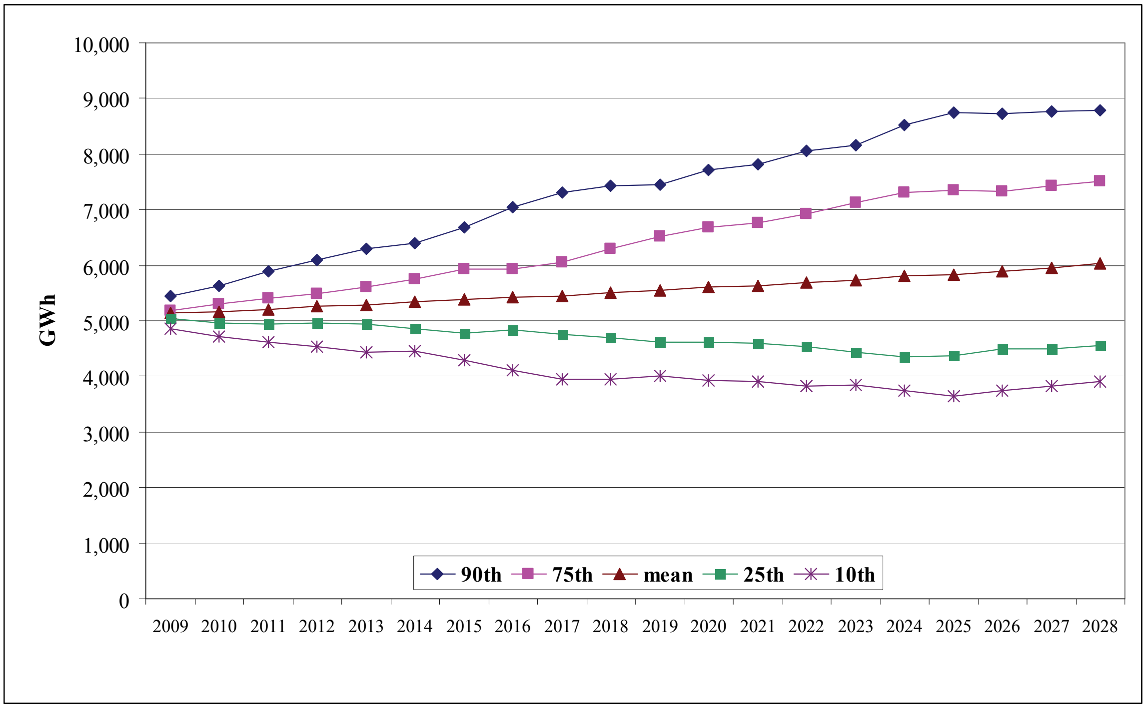


Figure 7.25 – Frequencies for West Main (California and Oregon) Loads

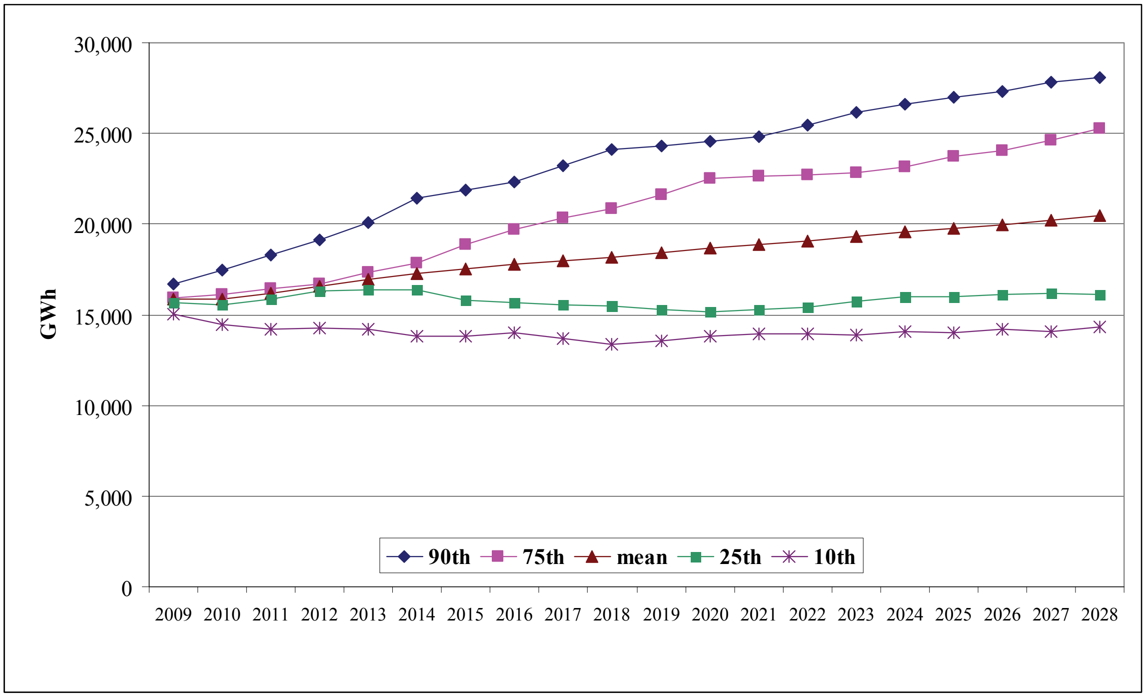


Figure 7.26 – Frequencies for Wyoming Loads

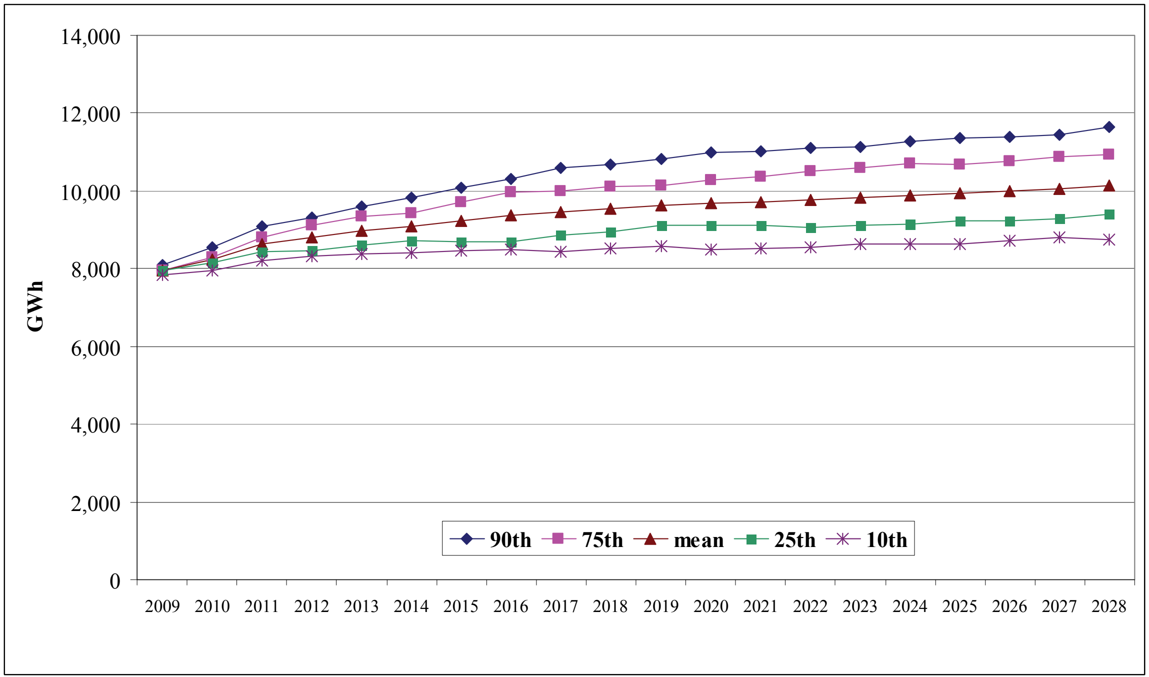
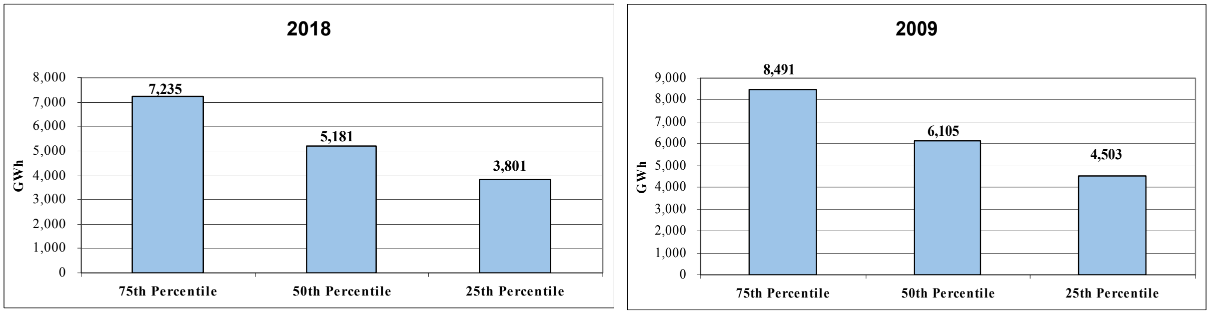


Figure 7.27 – Hydroelectric Generation Frequency, 2009 and 2018



PacifiCorp derives expected values for the Monte Carlo simulation by averaging run results across all 100 iterations. The Company also looks at subsets of the 100 iterations that signify particularly adverse cost conditions, and derives associated cost measures as indicators of high-end portfolio risk. These cost measures, and others used to rank portfolio performance, are described in the next section.

PORTFOLIO PERFORMANCE MEASURES

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

Cost
- Mean PVRR (Present Value of Revenue Requirements)
- Risk-adjusted mean PVRR
- Minimum PVRR cost exposure under CO_2 tax outcomes
- Customer rate impact
- Capital costs for the first ten years of the simulation period (2009-2018) and the total simulation (2009-2028)

Risk
- Upper-tail Mean PVRR
- 95th Percentile PVRR
- Production cost standard deviation

Supply Reliability
- Average annual Energy Not Served (ENS)
- Upper-tail ENS
- Loss of Load Probability (LOLP)

PacifiCorp reports the portfolio results for each CO_2 tax simulation, the straight average for the three CO_2 tax simulations, and multiple probability-weighted averages. The multiple probability-weighted averages reflect \$5/ton increments of the expected value (EV) CO_2 tax, ranging from

\$15/ton to \$70/ton. This range is in line with long run values that have appeared in federal and state legislative proposals.[43] The average values are converted to a normalized, 1-to-10 scaled score to preserve relative differences between measure results when combining the scores for composite ranking of the portfolios.

In addition to these stochastic measures, PacifiCorp reports fuel source diversity statistics and the emission footprint of each portfolio, focusing on generator emissions.

The following sections describe in detail each of these performance measures as well as the fuel source diversity statistics.

Mean PVRR

The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs for new resources determined by the System Optimizer model. The PVRR is reported in 2009 dollars as of January 1, 2009.

The net variable cost from the PaR simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales, and costs associated with making up for generation deficiencies (Energy Not Served costs; see the section on ENS below for background on ENS and the representation of ENS costs in the PaR model.) The variable costs included are not only for new resources but existing system operations as well. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components in the stochastic mean PVRR include renewable production tax credits and emission externality costs, such as a CO_2 tax.

The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO_2 cost adders. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand-side resources as evaluated in this IRP.

Risk-adjusted Mean PVRR

This measure—risk-adjusted PVRR for short—is calculated as the stochastic mean PVRR plus the expected value, EV, of the 95th percentile PVRR, where $EV = PVRR_{95} \times 5\%$. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations conducted for each production cost run.

The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts without eliciting and applying subjective weights that express the utility of trading one cost attribute for another.

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[43] For example, see, Metcalf, G., et al, Analysis of U.S. Greenhouse Gas Tax Proposals (Massachusetts Institute of Technology, Joint Program on the Science and Policy of Global Change, Report No. 160, April 2008). As an example of a state legislative CO_2 tax proposal, the Kansas House of Representatives considered a \$37/ton CO_2 tax to be levied on the state's electric utilities.

PacifiCorp also presents scatter-plot graphs of the stochastic mean PVRR versus upper-tail mean PVRR for portfolios as a means to visualize the tradeoff between expected and high-cost outcomes.

Minimum Cost Exposure under Alternative Carbon Dioxide Tax Levels

Cost exposure is the difference between a portfolio's risk-adjusted PVRR and the risk-adjusted PVRR of the best-performing portfolio for a given CO_2 tax level modeled in the Monte Carlo simulation. Each portfolio is ranked on the basis of the size of its maximum cost exposure realized under the three CO_2 tax levels: $0/ton, $45/ton, and $100/ton.

This ranking scheme is based on the Minimax Regret decision criterion, which focuses on avoiding the worst possible consequences that could result when making a decision. In decision theory, "regret" is defined as the exposure between a course of action taken and the best course of action possible given a particular state of nature.[44] If the decision-maker selects the course of action that turns out to be the best possible one, then the regret is zero. Conversely, the maximum regret occurs if the selected course of action results in the worst outcome among the possibilities. The minimax decision rule is to select the course of action that minimizes the maximum regret across the states of nature evaluated. This is a risk-averse stance applicable to decision-making under uncertainty.

To illustrate the application of the decision rule, the following matrix shows the cost outcomes given two alternative actions and two states of nature, designated as S_1 and S_2. Under state of nature S_1, the best possible cost outcome happens under Alternative 2; under state of nature S_2, the superior cost outcome happens under Alternative 1.

	Cost (Billion $)	
Alternative	**S_1**	**S_2**
1	18.00	23.00
2	10.00	28.00
Lowest Cost	**10.00**	**23.00**

To determine the maximum regret for the two alternatives, a loss matrix is constructed:

Loss Table (Billion $)

Alternative	S_1	S_2	Maximum Regret
1	8.00	0.00	**8.00**
2	0.00	5.00	**5.00**

The maximum regret for alternative 1 under state of nature S_1 is $8 billion, while the maximum regret for alternative 2 under state of nature S_2 is $5 billion. By applying the minimax decision

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[44] Regret is also called "opportunity loss", or the amount that would be lost by not picking the best alternative.

rule, alternative 2 would be selected because it has the lowest maximum loss under the two states of nature.

For PacifiCorp's minimax evaluation, the states of nature are the stochastic cost outcomes given the three CO_2 tax levels modeled in the Monte Carlo simulations ($0/ton, $45/ton, and $100/ton). The alternatives are the resource portfolios developed from the 21 core cases with the medium load growth assumption.

Customer Rate Impact

PacifiCorp calculates the customer rate impact associated with each of the portfolios based on the stochastic production cost results and capital costs reported for the portfolio by the System Optimizer model. The rate impact measure is the levelized net present value of the year-to-year changes in the customer dollar-per-megawatt-hour price for the period 2009 through 2028:

$$-PMT\left(NPV_{i=\{2010\rightarrow 2028\}}\left(\frac{Cost_i - Cost_{i-1}}{Load_i}\right)\right)$$

The cost in the rate numerator consist of the stochastic mean system operating cost (fuel cost, environmental cost, and variable O&M costs of all resources), combined with the fixed O&M and capital costs of the new supply-side and transmission resources.[45] The rate denominator is the retail load.

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

Capital Cost

The total capital cost measure is the sum of the capital costs for generation resources and transmission, expressed as a net present value. The capital costs are reported by the System Optimizer for each portfolio. Capital costs for the first 10 years of the simulation period, as well as the entire simulation period, are reported. The ten-year capital cost view (for resources added in 2009-2018), is intended to indicate the relative rate impact of the portfolios attributable to resource construction costs during the period considered in PacifiCorp's business plan.

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[45] New IRP resource capital costs are represented in 2008 dollars and grow with inflation, and start in the year the resource added. This method is used so resources having different lives can be evaluated on a comparable basis. The customer rate impacts will be lower in the early years and higher in the later years when compared to customer rate impacts computed under a rate-making formula.

Risk Measures

For this IRP, PacifiCorp relies on four stochastic cost risk measures: upper-tail mean PVRR, 5th and 95th percentile PVRR, and the standard deviation of production costs.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the five highest production costs on a net present value basis. The portfolio's real levelized fixed costs are added to these five production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The fifth and ninety-fifth percentile stochastic PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles on the basis of production costs (net present value basis), respectively. These measures represent snapshot indicators of low-risk and high-risk stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted PVRR measure.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2009 through 2028.

Supply Reliability

Average and Upper-Tail Energy Not Served

Certain iterations of a PaR stochastic simulation will have "energy not served" or ENS.[46] Energy Not Served is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. This occurs when an iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour. Typically large load shocks and simultaneous unplanned plant outages are implicated in ENS events. (Deterministic PaR simulations do not experience ENS because there is no random behavior of model parameters; for example, loads increase in a smooth fashion over time.) Consequently, ENS, when averaged across all 100 iterations, serves as a measure of the stochastic reliability risk for a portfolio's resources.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2009 through 2028 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Results using the $45/ton CO_2 tax are reported, as the tax level does not have a material influence on ENS amounts.

One change from previous IRPs related to the handling of ENS is the estimation of ENS costs included in the portfolio stochastic PVRR. In previous IRPs, PacifiCorp applied a single ENS cost for the PaR model, using the FERC price cap as a reasonable cost proxy for acquiring emergency power. PacifiCorp recognizes that, in practice, the planning response to significant ENS is

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[46] Also referred to as Expected Unserved Energy, or EUE.

different for short-run versus long-run ENS expectations. In the short-run, the Company would have recourse to few remedial options, and would expect to pay a large premium for emergency power. On the other hand, the Company has more planning options with which to respond to long-term forecasted ENS growth, including acquisition of peaking resources. Consequently, a tiered pricing scheme has been applied to ENS quantities generated by the Planning and Risk model. The ENS cost is set to $400/MWh (real dollars) for the first 50 GWh/yr of ENS, $200/MWh for the next 100 GWh/yr, and $100/MWh for all quantities above 150 GWh/yr. For large forecasted ENS quantities that occur in the out years of the study period, the acquisition of peaking generation would become cost-effective, with the $100/MWh reflecting the long-run all-in cost for such generation.

Loss of Load Probability

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

Mathematically, LOLP defined as:

$$\mathbf{LOLP} = \text{Prob}(\mathbf{S} < \mathbf{L})$$

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

Traditionally LOLP was calculated for each hour of the year, converted to a measure of statistically expected outage times or number of outage events (depending on the model), and summed for the year. The annual measure estimates the generating system's reliability. A high LOLP generally indicates a resource shortage, which can be due to generator outages, insufficient installed capacity, or both. Target values for annual system LOLP depend on the utilities' degree of risk aversion, but a level equivalent of one day per ten years is typical.

For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, only events that occur at the time of the regional peak are the ones likely to have significant consequences. Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Chapter 8, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring the winter season.

Fuel Source Diversity

For assessing fuel source diversity on a summary basis for each portfolio, PacifiCorp calculated the new resource generation shares for four broad fuel-type categories as reflected in the System Optimizer expansion plan:

- Renewables and DSM ("no fuel" generation plus a small quantity of biomass fuel)

- Natural gas
- Market
- Coal, including all types of coal-based technologies selected for the expansion plan
- Nuclear

To account for the timing impact of the assumed availability of coal and nuclear resources in the portfolios, the generation shares are reported for years 2013, 2020, and 2028. Conventional supercritical coal plants are picked up in the 2020 and 2028 snapshots, while nuclear and clean coal resources are picked up in the 2028 snapshot.

Another perspective on fuel diversity is the nameplate capacity mix for the portfolios. Appendix A contains area charts for all portfolios developed that show the resource nameplate capacity mix by year. Nameplate capacity for resources selected by the System Optimizer is grouped into the following new resource categories: gas, DSM, distributed generation, wind, other renewables, clean coal, conventional coal, energy storage, other renewables, market purchases, and growth resources.

TOP-PERFORMING PORTFOLIO SELECTION

For this IRP, PacifiCorp has instituted a weighted scoring scheme that combines selected portfolio performance measures into an overall composite preference score. The cases selected for performance ranking include the core cases defined with the medium load growth assumption (to maintain cost comparability with respect to the amount of resources required) as well as cases 46 and 47 (the two business plan reference portfolios).

The measures used in the weighted scoring scheme, along with their importance weights (which sum to 1), include the following:

Table 7.8 – Measure Importance Weights for Portfolio Ranking

Cost Measures	**Weight**
Risk-adjusted PVRR	45%
Customer Rate Impact	20%
Capital Cost for 2009-2018	5%
Risk Measures	**Weight**
CO_2 Cost Exposure	15%
Production Cost Standard Deviation	5%
Average annual ENS	5%
Average Annual Probability of ENS events for July exceeding 25 GWh	5%
Total	**100%**

Risk-adjusted PVRR represents the long-run cost performance for a portfolio, accounting for the potential for a high-cost outcome and its associated cost on an expected value basis. Consequently, this criterion is given the largest weight among the performance measures. The customer rate impact measure gauges long-run retail rate variability for a portfolio; given two portfolios with equivalent long-run costs, the portfolio that has lower retail rate variability is preferred. The 10-year capital cost criterion reflects the role that near-term capital expenditures plays in determining portfolio affordability and financeability for purposes of business plan preparation.

For portfolio risk measures, cost exposure under alternative CO_2 tax levels reflects a portfolio's potential for avoiding worst-case cost outcomes given CO_2 regulatory policy uncertainty; it is a measure of CO_2 cost risk, and has been given the largest weight among risk measures included in the preference scoring process. The three other risk measures reflect variable cost variability and supply reliability attributes, and have been given a combined weight of 15 percent for preference scoring.

Table 7.9 shows a sample of the preference-scoring grid for the optimized portfolios. To determine the preference scores for the portfolios, PacifiCorp conducted the following steps:

1. Calculate the normalized (scaled from 1 to 10) rankings for the probability-weighted average stochastic cost measures (risk-adjusted PVRR, customer rate impact, CO_2 cost exposure, and the standard deviation of production costs). Rankings are determined for each of 12 expected value CO_2 tax levels, ranging from $15 to $70.
2. Calculate the normalized rankings for the 10-year capital costs, average annual ENS, and July event LOLP.
3. Populate the portfolio preference-scoring grid with the normalized rankings. The weighted ranking for each portfolio is the sum of each individual performance ranking multiplied by its importance weight. These weighted rankings are then converted to final preference scores by scaling the rankings to a 1 to 10 range.

Table 7.9 – Portfolio Preference Scoring Grid

	Cost Measures			Risk Measures					
Case [1/]	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1								0.0	0.0
2								0.0	0.0
3								0.0	0.0
5								0.0	0.0
8								0.0	0.0
9								0.0	0.0
10								0.0	0.0
11								0.0	0.0
14								0.0	0.0
17								0.0	0.0
18								0.0	0.0
19								0.0	0.0
20								0.0	0.0
22								0.0	0.0
24								0.0	0.0
25								0.0	0.0
26								0.0	0.0
27								0.0	0.0
29								0.0	0.0
46								0.0	0.0
47								0.0	0.0

Importance Weights	45%	20%	5%	15%	5%	5%	5%

The net result was a set of 12 preference-scoring grids, one for each expected value CO_2 tax level. For determining the top-performing portfolios, PacifiCorp calculated the average of the preference scores across the CO_2 tax levels, as well as inspected the variability of the scores as the CO_2 level increased.

The top three portfolios on the basis of the preference scores were selected as final preferred portfolio candidates. Three portfolios represent a manageable number in light of the data processing and model run-time requirements associated with phase 6, deterministic risk assessment of the top-performing portfolios.

SCENARIO RISK ASSESSMENT

The purpose of phase 6 is to determine the range of deterministic costs that could result given a fixed set of resources under varying gas/electricity price and CO_2 cost assumptions, the two main sources of portfolio risk. The Public Service Commission of Utah, in its acknowledgment order for PacifiCorp's 2007 IRP, directed the Company to consider this step for the 2008 IRP.

PacifiCorp used the System Optimizer to determine PVRRs for the three top-performing portfolios under a subset of the core cases (Scenario Risk Cases). For these runs, the System Optimizer dispatches the fixed set of portfolio resources as part of its least-cost portfolio solution. The PVRR comparisons thus indicate the production cost differences under the alternative cost scenarios.

As with the performance ranking process, PacifiCorp selected only those cases with the medium load growth assumption. Cases were also restricted to those using the June 2008 forward price curve. These selection rules resulted in 10 cases and total of 30 System Optimizer runs to support this analysis as shown in Table 7.10.

Table 7.10 – Cases Selected for Deterministic Risk Assessment

Case	CO_2 Tax Level (2008 dollars)	Base Gas Cost
1	$0/ton	Low
2	$0/ton	Medium
3	$0/ton	High
5	$45/ton	Low
8	$45/ton	Medium
14	$45/ton	High
17	$70/ton	Medium
22	$70/ton	High
24	$100/ton	Medium
29	$100/ton	High

In parallel with the stochastic risk analysis, PacifiCorp reports a measure of central tendency (mean PVRR) and variation (PVRR standard deviation) for the portfolio results, as well as ranked each portfolio and computed the rank sum as an overall performance indicator.

PREFERRED PORTFOLIO SELECTION AND ACQUISITION RISK ANALYSIS

The preferred portfolio is selected from the three top-performing portfolios on the basis of the portfolio preference scores, and then consideration of resource risks and fuel source diversity.

Using the preferred portfolio as the starting point, PacifiCorp conducts a next best alternative (NBA) analysis that applied a number of procurement risk scenarios to determine optimal portfolios in the event of unplanned circumstances. The focus of the NBA analysis is on key firm-planned and new resources reflected in the preferred portfolio.

8. MODELING AND PORTFOLIO SELECTION RESULTS

INTRODUCTION

This chapter reports modeling and portfolio performance evaluation results for the portfolios developed with alternate input assumptions using the System Optimizer model. The preferred portfolio is presented, along with a discussion of the relative advantages and risks associated with the top-performing portfolios.

Discussion of the portfolio evaluation results falls into the following 12 sections.
Portfolio Development Results – This section presents the System Optimizer resource portfolios, describing resource preferences as a function of the model input assumptions and profiling resource utilization patterns for each portfolio. Analysis results for several sensitivity case portfolios are also presented.

- Stochastic Simulation Results - Candidate Portfolios – This section reports the stochastic modeling results and cost/risk measure ranking results for each of the 21 candidate portfolios.
- Load Growth Impact on Resource Choice – This section compares the stochastic modeling results for portfolios developed with alternative load growth assumptions.
- Capacity Planning Reserve Margin – This section describes the stochastic cost and risk analysis of portfolios developed with 12 and 15 percent capacity planning reserve margins.
- Probability-weighted Stochastic Cost Results – This section reports the stochastic cost measures as probability-weighted averages of the results for the three CO_2 tax simulations: $0, $45, and $100/ton in 2008 dollars. These results are key inputs in the overall portfolio preference scoring process.
- Fuel Source Diversity – This section provides statistics on generation shares by fuel type for all the portfolios; three snap shot years are profiled: 2013, 2020, and 2028.
- Emissions Footprint – This section reports for each portfolio the annual emission quantities of CO_2, sulfur dioxide, nitrous oxides, and mercury for 2009-2028.
- Top-performing Portfolio Selection – This section describes the results of the portfolio cost/risk measure ranking and preference scoring, and identifies the four top-performing portfolios chosen as final candidates for preferred portfolio selection.
- Scenario Risk Assessment – This section describes the deterministic scenario analysis conducted for the three top-performing portfolios, concluding with a critique of the value of this type of analysis for the IRP.
- Portfolio Impact of the 2012 Gas Resource Deferral Decision – This section describes the portfolio analysis conducted to reflect the removal of the Lake Side II combined-cycle plant as a planned resource for 2012.
- Wind Resource Acquisition Schedule Development – This section discusses the model selection of wind resources and how business planning implementations must be considered.
- Portfolio Impact of PacifiCorp's February 2009 Load Forecast – This section presents the portfolio developed to account for a new load forecast prepared in February 2009.

- Preferred Portfolio Selection – This section compares the top-performing portfolios, profiling their relative advantages and risks and pulling in the portfolio analysis conducted for the Lake Side II construction cancellation and revised load forecast. The portfolio that is the most desirable after considering cost, risk and uncertainty is then presented.

PORTFOLIO DEVELOPMENT RESULTS

Tables 8.1 and 8.2 show the cumulative capacity additions by resource type for the portfolios for years 2009-2018 and 2009-2028, respectively. Megawatt amounts for front office transactions and growth resources represent annual averages: 20 years for FOT, and eight years for growth resources. (The detailed portfolio resource tables are included in Appendix A.)

Table 8.1 – Portfolio Capacity Additions by Resource Type, 2009 – 2018

				Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market Resources) [1/]							
Case	PVRR	Gas Scenario / FPC	CO2 Price	SCPC	Gas	Wind	Dist. Gen	Market Purchases (10-yr Avg)	Other Renewables	DSM Class 1	DSM Class 2
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)											
1	$20,045	Low - June 2008	$0		261		124	748		108	716
2	$21,512	Medium - June 2008	$0	600	261	140	85	646	35	2	890
3	$19,503	High - June 2008	$0	790		3,291	95	530	155	7	982
5	$40,526	Low - June 2008	$45		261	1,050	95	691	35	2	901
8	$41,372	Medium - June 2008	$45			2,400	147	663	120	7	955
9	$40,204	Low - Oct 2008	$45		261	1,280	95	690	35	2	899
10	$40,319	Medium - Oct 2008	$45			2,400	117	679	155	7	949
11	$40,559	High - Oct 2008	$45	600		4,814	103	546	155	7	1,001
14	$39,949	High - June 2008	$45	600		5,355	107	500	155	7	1,018
17	$51,207	Medium - June 2008	$70			3,900	110	613	155	7	985
18	$49,745	Low - Oct 2008	$70			3,900	110	640	155	7	954
19	$50,102	Medium - Oct 2008	$70			4,100	110	620	155	7	975
20	$50,536	High - Oct 2008	$70			5,250	104	602	155	7	1,007
22	$49,983	High - June 2008	$70	600		5,750	101	514	155	7	1,048
24	$60,693	Medium - June 2008	$100			5,739	112	565	155	7	1,009
25	$58,838	Low - Oct 2008	$100			5,250	112	742	155	7	1,000
26	$59,660	Medium - Oct 2008	$100			5,250	112	661	155	7	1,007
27	$60,484	High - Oct 2008	$100			5,750	110	648	155	7	1,045
29	$57,635	High - June 2008	$100			5,750	158	538	155	110	1,079
46	$21,532	Medium - Oct 2008	$8, C&T		174	600	136	641		19	906
47	$20,863	Medium - Oct 2008	$8, C&T		174	822	136	646		29	903
Low Load Growth Core Cases											
4	$34,612	Low - June 2008	$45			300	91	216	35		882
7	$34,582	Medium - June 2008	$45			1,800	91	172	85		920
13	$31,076	High - June 2008	$45	600		4,610	95	121	155		1,004
16	$43,523	Medium - June 2008	$70			3,599	109	116	155		962
21	$40,517	High - June 2008	$70			5,750	95	134	155		1,017
23	$51,692	Medium - June 2008	$100			5,559	111	101	155		1,005
28	$47,806	High - June 2008	$100			5,750	95	242	155		1,017
High Load Growth Core Cases											
6	$48,140	Low - June 2008	$45		1,363	904	192	755	155	126	957
12	$50,146	Medium - June 2008	$45	600	888	1,907	151	748	155	107	994
15	$50,914	High - June 2008	$45	600	261	5,750	153	771	655	114	1,079
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth											
30	$48,541	Medium - June 2008	$45 to $179			4,400	110	621	155	7	1,003
31	$47,552	High - June 2008	$45 to $179			5,750	110	533	155	7	1,072
Sensitivity Case - High Cost Outcome											
33	$69,949	High - June 2008	$100	600	577	5,750	158	662	655	126	1,113
Sensitivity Cases - Clean Base-Load Generation Availability											
34	$40,564	Medium - June 2008	$45			3,183	138	647	85	7	950
35	$39,853	High - June 2008	$45	600		5,000	97	528	120	7	1,015
36	$51,242	Medium - June 2008	$70			4,200	147	681	120	7	1,002
37	$48,949	High - June 2008	$70			5,750	95	595	120	7	1,019
Sensitivity Cases - High Plant Construction Costs											
38	$41,974	Medium - June 2008	$45			1,605	138	665	85	64	968
39	$34,791	High - June 2008	$45	600		3,182	142	493	120	109	1,020
Sensitivity Case - System-wide Oregon CO2 Reduction Targets											
40	$24,761	Medium - June 2008	Hard Cap			1,241	124	677	85	104	920
Sensitivity Cases - Planning Reserve Margin, 15%											
41	$41,542	Medium - June 2008	$45		261	1,934	151	776	155	25	954
42	$51,420	Medium - June 2008	$70		261	3,600	110	764	155		983
43	$60,905	Medium - June 2008	$100			5,750	154	713	155	105	1,036
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)											
44	$21,249	Medium - Oct 2008	$8, C&T	600		1,746	132	632	85	109	900
45	$20,875	Medium - Oct 2008	$8, C&T	600	261	721	89	654	35	2	877
Sensitivity Case - Class 3 DSM for Peak Load Reduction											
48	$41,268	Medium - June 2008	$45			2,400	107	643	85	121	945

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

Table 8.2 – Portfolio Capacity Additions by Resource Type, 2009 – 2028

				Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market and Growth Resources)[1/]											
Case	PVRR	Gas Scenario / FPC	CO2 Price	SCPC	SCPC w/ CCS	IGCC w/ CCS	Gas	Wind	Dist. Gen	Nuclear	Market Purchases (20-yr Avg)	Growth Resource (8-yr Avg, 2021-2028)	Other Renewables	DSM Class 1	DSM Class 2
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)															
1	$20,045	Low - June 2008	$0				261		130		1,102	859		108	1,537
2	$21,512	Medium - June 2008	$0	600			261	941	109		880	524	35	2	1,815
3	$19,503	High - June 2008	$0	790				4,003	95		713	437	155	7	1,992
5	$40,526	Low - June 2008	$45		346		261	1,600	110		1,089	734	35	2	1,835
8	$41,372	Medium - June 2008	$45					2,400	160		1,090	624	120	7	1,942
9	$40,204	Low - Oct 2008	$45		346		261	1,600	110		1,133	623	35	2	1,834
10	$40,319	Medium - Oct 2008	$45					2,600	129		1,124	513	155	7	1,936
11	$40,559	High - Oct 2008	$45	600				5,000	114		717	651	155	7	2,024
14	$39,949	High - June 2008	$45	600		466		6,287	120		711	272	155	7	2,066
17	$51,207	Medium - June 2008	$70		876			3,900	122		1,084	609	155	7	2,020
18	$49,745	Low - Oct 2008	$70		876			3,900	122		1,089	667	155	7	1,974
19	$50,102	Medium - Oct 2008	$70		876			4,100	122		1,094	610	155	7	2,009
20	$50,536	High - Oct 2008	$70		876			6,600	114	1,600	842	651	155	7	2,035
22	$49,983	High - June 2008	$70	600	876			7,200	101	1,600	616	161	155	7	2,115
24	$60,693	Medium - June 2008	$100		876			6,600	122	3,200	802	280	155	7	2,076
25	$58,838	Low - Oct 2008	$100		876			6,175	122		1,070	777	155	7	2,035
26	$59,660	Medium - Oct 2008	$100		876			6,600	122	3,200	783	311	155	7	2,042
27	$60,484	High - Oct 2008	$100		876			6,680	120	3,200	972	650	155	7	2,098
29	$57,635	High - June 2008	$100		876	466		7,200	167	3,200	575	450	155	110	2,183
46	$21,532	Medium - Oct 2008	$8, C&T	600			174	1,388	151		897	468		19	1,825
47	$20,863	Medium - Oct 2008	$8, C&T	600			174	1,344	151		892	469		29	1,822
Low Load Growth Core Cases															
4	$34,612	Low - June 2008	$45		346			300	110		269	125	35		1,801
7	$34,582	Medium - June 2008	$45		346			1,800	110		185	115	85		1,857
13	$31,076	High - June 2008	$45	600				4,800	95		71	81	155		2,038
16	$43,523	Medium - June 2008	$70		876			3,599	122		108	111	155		1,990
21	$40,517	High - June 2008	$70		876			6,202	95	1,600	124	70	155		2,058
23	$51,692	Medium - June 2008	$100		876			6,600	122	3,200	157	85	155		2,045
28	$47,806	High - June 2008	$100		876			5,800	95	3,200	150	67	155		2,036
High Load Growth Core Cases															
6	$48,140	Low - June 2008	$45				1,838	1,600	209		1,181	1,125	155	126	1,983
12	$50,146	Medium - June 2008	$45	600			888	2,299	169		1,186	1,125	155	126	2,082
15	$50,914	High - June 2008	$45	600		466	261	6,599	169	1,600	1,148	572	655	125	2,163
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth															
30	$48,541	Medium - June 2008	$45 to $179		876	466		7,000	122	3,200	743	126	155	7	2,091
31	$47,552	High - June 2008	$45 to $179		876			7,200	122	3,200	815	130	155	7	2,159
Sensitivity Case - High Cost Outcome															
33	$69,949	High - June 2008	$100	600			1,100	7,200	169		762	1,125	655	126	2,294
Sensitivity Cases - Clean Base-Load Generation Availability															
34	$40,564	Medium - June 2008	$45					3,900	152		1,109	539	85	7	1,937
35	$39,853	High - June 2008	$45	600				5,000	97		778	479	120	7	2,022
36	$51,242	Medium - June 2008	$70		876			4,200	169		1,127	762	120	110	2,046
37	$48,949	High - June 2008	$70		876			5,762	95	3,200	468	150	120	7	2,061
Sensitivity Cases - High Plant Construction Costs															
38	$41,974	Medium - June 2008	$45					2,118	151		1,114	535	85	64	1,970
39	$34,791	High - June 2008	$45	600				3,255	149		641	580	120	109	2,113
Sensitivity Case - System-wide Oregon CO2 Reduction Targets															
40	$24,761	Medium - June 2008	Hard Cap		876			2,200	124		999	1,000	85	104	1,880
Sensitivity Cases - Planning Reserve Margin, 15%															
41	$41,542	Medium - June 2008	$45				261	1,934	163		1,168	590	155	25	1,941
42	$51,420	Medium - June 2008	$70		876		261	3,600	122		1,160	679	155		2,017
43	$60,905	Medium - June 2008	$100		876			6,600	163	3,200	907	291	155	105	2,104
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)															
44	$21,249	Medium - Oct 2008	$8, C&T	600				5,673	149		948	161	155	109	1,811
45	$20,875	Medium - Oct 2008	$8, C&T	600			261	881	110		904	430	120	2	1,795
Sensitivity Case - Class 3 DSM for Peak Load Reduction															
48	$41,268	Medium - June 2008	$45					2,400	122		1,037	679	85	121	1,932

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

Wind Resource Selection

Wind resource selection varied considerably across the portfolios, ranging from no resources in one portfolio (case 1, with no CO_2 tax and low gas prices) to 7,200 MW in five portfolios (cases 11, 29, 30, 31, and 33—all based on high gas prices and a CO_2 tax of $70 or greater). For the $45 CO_2 tax core cases with medium load growth, the amount of wind capacity averaged over 3,200 MW. For the $70 and $100 CO_2 tax core cases with medium load growth, the amount of wind capacity averaged over 5,100 MW and 6,600 MW, respectively. System Optimizer found wind to be cost-effective for displacing gas generation under high gas price scenarios, reducing CO_2 taxes, and selling to markets during off-peak periods.

Regarding the timing of wind additions, the model generally started adding wind capacity early in the study period, from 2010 to 2012, with large and constant amounts included in response to high gas prices, high CO_2 tax values, or both. For these cases, the model often selected amounts up to the limit allowed in a year (500 MW prior to 2014, and 750 MW in 2014 and thereafter). In only a few of the cases was wind added after 2020, generally to help meet RPS requirements owing to less wind investment made earlier in the study period (for example, cases 2 and 5). The expiration of the renewable PTC in 2013 (case 45) was found to significantly impact the amount and timing of wind additions; no wind was added after 2012.

An important caveat to these results is that System Optimizer does not account for reliability impacts and associated costs from adding large amounts of wind to the system.

Gas Resource Selection

Intercooled aeroderivative (IC aero) SCCT plants were the most common gas resource included in the portfolios, occurring in cases having low gas prices combined with either the $0 or $45 CO_2 tax, or medium gas prices combined with no CO_2 tax. The SCCT plant (261 MW) was always selected in 2016.

Combined-cycle gas plants were selected infrequently, only appearing in three scenario situations: high load growth and either the low or medium gas price assumptions (cases 6 and 12), and the high-cost bookend scenario (case 33). The model chose only west-side CCCT units with a 2015 in-service date.

Class 1 Demand-side Management Resource Selection

The model selected a small amount of Class 1 DSM capacity, 2 to 7 MW, for most of the portfolios, favoring Idaho dispatchable irrigation over other programs. This capacity was added most commonly between 2016 and 2018, with the earliest additions in 2013 for portfolios with no wind capacity chosen in the early years. Additions reached over 100 MW for high load growth scenarios, while no capacity was added in any of the portfolios developed with the low load growth scenario. Of the core cases with medium load growth, only two cases—numbers 1 and 29—included more than 100 MW. For case 1, which was based on no CO_2 tax and low gas prices, Class 1 DSM appears to substitute for renewables capacity added in most other portfolios. For case 29, the selection of Class 1 DSM is driven by low utilization of gas plants stemming from the combination of the $100 CO_2 tax and high gas prices.

Class 2 Demand-side Management Resource Selection

The model selected a sizable amount of Class 2 DSM in all portfolios by 2028, ranging from 1,537 MW to 2,183 MW, and adding this DSM on a relatively constant basis for every year of the simulation period. For the medium load growth portfolios, the average amount included was 1,970 MW. The variation of the DSM among these portfolios, as measured by the standard deviation, was only about 130 MW.

Supercritical Pulverized Coal Resource Selection

The model selected supercritical coal plants in response to the following set of conditions:

- No CO_2 tax combined with medium or high gas prices (cases 2 and 3)
- The \$8 CO_2 cap-and-trade allowance price (cases 44 and 45, and business plan reference cases 46 and 47)
- The \$45 CO_2 tax combined with high gas prices (cases 11, 14, 35, and 39)
- The \$45 CO_2 tax with low load growth, combined with high gas prices (case 13)
- The \$45 CO_2 tax with high load growth, combined with either medium or high gas prices (cases 12 and 15)
- The \$70 CO_2 tax combined with high gas prices (case 22)

Only one coal plant was included in these portfolios. The plant was always selected in 2018, except for the two business plan reference cases, where it was added in 2019.

The combination of scenario inputs for which supercritical coal plants were chosen indicates that determining a CO_2 cost trigger point at which coal plants are no longer cost-effective has limited value without considering the impact of gas prices.

Geothermal Resource Selection

Geothermal was included in a large majority of the case portfolios, and generally selected in 2013—the first year of availability. The Blundell 3 project appeared in all portfolios where this resource was configured as an option, except for case 1 (defined with no CO_2 tax and low gas prices). The green-field projects in both the east and west were not cost-effective in a number of low load growth scenarios, but frequently appeared in the portfolios developed with all other combinations of scenario input values.

An interesting result of enforcing the high renewable portfolio standard requirement for case 44 was that the geothermal resources were deferred from their typical 2013 in-service dates: the Blundell 3 project was added in 2015, while the east and west green-field resources were added in 2020 and 2025, respectively. The model followed a similar deferral strategy for case 45, where the production tax credit expired in 2013. For this portfolio, Blundell 3 was deferred to 2016, while the west green-field resource was deferred to 2023.

Nuclear Resource Selection

Nuclear plants become cost-effective resource alternatives under high gas price and CO_2 tax scenarios; they are also always selected in 2025, the earliest in-service year. A 1,600 MW unit was chosen with a \$70 CO_2 tax combined with high gas prices. The model selected a 3,200 MW unit given a \$100 CO_2 tax and medium or high gas prices. There is no clear preference for nuclear resources given the level of load growth assumed.

Clean Coal Resource Selection

Clean coal technologies appear under the \$45 CO_2 tax in limited circumstances; only in combination with low gas and electricity prices. Under medium gas price scenarios, renewables, energy efficiency, and distributed generation substitute for a single pulverized coal CCS retrofit project. Only under the highest gas/electricity prices (June 2008 forward price curve) does IGCC become cost-effective with a \$45 CO_2 tax.

Multiple pulverized coal CCS retrofit units are added in all portfolios specified with the \$70 and \$100 CO_2 tax. IGCC capacity is only added under the June 2008 high gas price scenario.

Short-term Market Purchase Selection

Reliance on front office transactions varies substantially among the portfolios. They are utilized more heavily under the low and medium gas price scenarios. In contrast, portfolios with large quantities of wind or base-load coal tend to rely less on them. The portfolios do not exhibit a correlation between the CO_2 tax level and the amount of front office transactions.

Distributed Generation Selection

Distributed generation resources—CHP and standby generation—was selected in all the portfolios, and ranged from 95 MW in case 3 (medium load growth, no CO_2 tax, and high June 2008 gas price scenario) to 209 MW in case 6 (high load growth, \$45 CO_2 tax, and low June 2008 gas price scenario).

Standby generation, biomass CHP, and the Kern River Recovered Energy Generation projects were most commonly selected. Standby generation and biomass always appeared in the first year of availability (2009), while the Kern River REG units appeared between 2011 and 2015. The low biomass fuel price assumed for the CHP resource explains why it appears in all the portfolios. Quantities were typically added in constant amounts each year until 2018. Kern River REG units were not selected under low load growth scenarios, or a combination of the \$45 CO_2 tax and low gas price scenarios. Additions of reciprocating engine CHP were less common, and are sensitive to the gas prices assumed. System optimizer generally started adding this type of CHP resource in the 2012-2013 time frame, with constant amounts (typically 1 or 2 MW) appearing in each year.

There is no single factor that accounts for the amount of distributed generation capacity selected; rather, a combination of low or medium gas price scenarios and higher CO_2 tax levels appear associated with larger quantities added.

Emerging Technology Resource Selection

Emerging technologies—solar, energy storage, and fuel cells—were rarely selected by the model, and appear in no more than one portfolio. The portfolio for case 15 includes 500 MW of solar thermal with natural gas backup (250 MW in 2014 and 2015), added in response to a \$45 CO_2 tax and high load growth and gas prices. Compressed air energy storage and battery storage appear in case 12 as a response to a \$45 CO_2 tax combined with high load growth and medium gas prices. (CAES air compression is fueled by simple-cycle combustion turbines). These technologies are added late in the simulation period, after 2025. Finally, fuel cells appear in the portfolio for case 6 in 2016 (40 MW in the east side), developed with high load growth, low gas prices, and the \$45 CO_2 tax.

Transmission Option Selection

PacifiCorp included three transmission resource options in System Optimizer:

- An Energy Gateway West expansion totaling 750 MW (Path C to West Main) available in 2015
- A Walla Walla to West Main transmission project available beginning in 2014, with capacity options of 200 MW and 400 MW

System Optimizer did not these transmission options in any of the portfolios.

Incremental Resource Selection under Alternative Load Growth Scenarios

Observations concerning the incremental resources selected as load growth increases are as follows:

\$45/ton CO_2 Tax and Low Gas Prices

- Moving from low to medium load growth, System Optimizer chose front office transactions as the dominant resource for meeting load. Mead and Mona FOT were relied on heavily beginning in 2013 and 2017, respectively. Additionally, the model added an IC aero SCCT in 2016 (261 MW), a significant amount of east-side wind (750 MW by 2018, and another 450 MW by 2021), and a small quantity of east-side Class 2 DSM.
- Moving from medium to high load growth, the model added a diverse mix of resource types. Incremental resources included: combined-cycle (1,100 MW by 2018 and another CCCT plant added in 2020); 123 MW of Class 1 DSM by 2014; 131 MW of Class 2 DSM by 2028, 40 MW of fuel cell capacity by 2016, 50 MW of utility-scale biomass by 2016, and west-side front office transactions in the out-years. No incremental wind capacity was added.

\$45/ton CO_2 Tax and Medium Gas Prices

- Moving from low to medium load growth, System Optimizer relied mostly on front office transactions and wind to serve the higher loads. The incremental resource mix included 600 MW of wind, CHP, distributed standby generation, west-side geothermal, and Class 2 DSM.
- Moving from medium to high load growth, the optimal resource mix shifted to conventional thermal resources and fewer wind additions. A coal plant and IC aero SCCT plant were added in the east during the first 10 years of the study period, with a consequent reduction in east-side wind (about 500 MW), while a combined cycle plant was added in the west. A significant amount of Class 1 DSM was also added (118 MW), along with Class 2 DSM.

\$45/ton CO_2 Tax and High Gas Prices

- Moving from low to medium load growth, the model chose wind and, despite the high gas prices, front office transactions, as the primary resources needed to serve load. By 2021, the model added about 1,500 MW of wind. From 2017 through 2028, the model selected Mead front office transactions, averaging 460 MW per year. An IGCC plant was also added in 2025.

- Moving from medium to high load growth, System Optimizer added 250 MW of solar in both 2014 and 2015, and added an east-side IC Aero SCCT in 2016. Other resource additions include: front office transactions (Mead and Mid-Columbia); 84 MW of Class 1 DSM by 2020; 96 MW of Class 2 DSM by 2025; over 300 MW of wind (400 MW added in the east—accelerated by two years—along with a 100 MW reduction in the west); 47 MW of distributed standby generation, and; a 1,600 MW nuclear unit in 2015.

$70/ton CO_2 Tax and Low Gas Prices

Moving from low to medium load growth, the dominant resources for meeting the higher loads are wind and front office transactions. The model added 300 MW of wind by 2018. Selection of all available Mead and Mona front office transactions began in 2018, while use of Mid-Columbia transactions ramped up from 2013 to full utilization by 2020 and beyond. Additional Class 2 DSM was also selected, reaching 86 MW by 2023.

$70/ton CO_2 Tax and Medium Gas Prices

Moving from low to medium load growth, the model chose a conventional pulverized coal plant in 2018 and additional wind. On the east-side, it added 911 MW of wind from 2018 through 2020, and deferred west-wide wind additions to 2019 and 2020. This wind resource timing suggests that the model's strategy was to dilute the coal plant's CO_2 tax impact by adding wind.

$100/ton CO_2 Tax and Medium Gas Prices

Moving from low to medium load growth, System Optimizer relied on wind and front office transactions to address the higher load growth. Unlike the $70/ton scenario, the model did not find it cost-effective to add a conventional coal resource and offset it with wind or other renewables. In the out-years, the portfolio relied on both front office transactions (primarily Mid-Columbia) and growth resources to meet load.

$100/ton CO_2 Tax and High Gas Prices

Moving from low to medium load growth, System Optimizer depended heavily on wind resources to meet load, adding 1,351 MW in two years: 2019 and 2020. Additionally, the model increased reliance on front office transactions, although this reliance was temporary in the east side (2018 through 2020). The model also chose addition DSM, including 110 MW of Class 1 DSM and 147 MW of Class 2 DSM.

Thermal Resource Utilization

Table 8.3 shows for gas and coal resources the average annual capacity factors for each portfolio, reflecting both existing and new resources. The capacity factors are reported for the entire simulation period, as well as for the following periods: 2009-2012 (capturing plant operations before a CO_2 tax goes into effect), 2013-2020, and 2021-2028.

The impact of the CO_2 tax on plant dispatch is shown by comparing the capacity factors for the 2009-2012 and 2013-2020 periods for the various gas price scenarios. Low gas prices cause the tax burden to fall on the coal plants, which realize a typical 10-percentage-point utilization decrease under a \$45 CO_2 tax, a 20-percentage-point utilization decrease under a \$70 CO_2 tax, and a 50 percentage point decrease under the \$100 CO_2 tax. With a \$100 CO_2 tax, a number of coal plants become uneconomic to operate, dispatching with a capacity factor in the single digits.

As gas prices increase in combination with a CO_2 tax, the tax burden shifts to the gas plants, which see a large drop-off in utilization. Under a \$100 CO_2 tax and high gas price scenarios, coal plant utilization drops by 10 to 16 percentage points.

Table 8.3 – Average Annual Thermal Resource Capacity Factors by Portfolio

			Gas Plant Capacity Factors (%)				Coal Plant Capacity Factors (%)			
Case	**Gas Price Scenario / FPC**	**CO2 Price**	**Average, 2009-2012**	**Average, 2013-2020**	**Average, 2021-2028**	**Average, 2009-2028**	**Average, 2009-2012**	**Average, 2013-2020**	**Average, 2021-2028**	**Average, 2009-2028**
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)										
1	Low - June 2008	$0	33	39	61	47	86	87	88	87
2	Medium - June 2008	$0	30	30	40	34	86	87	88	87
3	High - June 2008	$0	34	17	16	20	86	87	88	87
5	Low - June 2008	$45	35	40	59	46	86	73	71	75
8	Medium - June 2008	$45	31	28	46	36	86	86	86	86
9	Low - Oct 2008	$45	42	40	64	50	86	76	73	77
10	Medium - Oct 2008	$45	57	34	57	48	85	86	87	86
11	High - Oct 2008	$45	38	14	18	21	86	86	85	86
14	High - June 2008	$45	25	11	13	15	86	86	87	86
17	Medium - June 2008	$70	30	29	48	37	86	72	68	73
18	Low - Oct 2008	$70	42	42	75	55	86	54	46	57
19	Medium - Oct 2008	$70	57	33	62	49	85	71	64	71
20	High - Oct 2008	$70	37	12	14	18	86	82	77	81
22	High - June 2008	$70	25	10	11	14	86	84	81	83
24	Medium - June 2008	$100	28	31	48	37	86	52	37	53
25	Low - Oct 2008	$100	41	43	69	53	86	34	29	42
26	Medium - Oct 2008	$100	56	36	57	48	85	49	37	51
27	High - Oct 2008	$100	36	13	10	16	86	71	60	69
29	High - June 2008	$100	20	5	6	8	86	76	57	71
46	Medium - Oct 2008	$8, C&T	35	35	58	44	86	87	88	87
47	Medium - Oct 2008	$8, C&T	35	35	58	44	86	87	88	87
Low Load Growth Core Cases										
4	Low - June 2008	$45	34	39	63	48	86	71	68	73
7	Medium - June 2008	$45	30	24	38	31	86	86	86	86
13	High - June 2008	$45	25	9	10	13	86	84	83	84
16	Medium - June 2008	$70	29	24	41	32	86	70	64	70
21	High - June 2008	$70	25	8	8	12	86	83	78	82
23	Medium - June 2008	$100	27	28	40	33	86	48	32	49
28	High - June 2008	$100	20	4	3	7	86	72	49	65
High Load Growth Core Cases										
6	Low - June 2008	$45	36	40	55	45	86	73	71	75
12	Medium - June 2008	$45	32	27	42	34	86	86	87	86
15	High - June 2008	$45	26	14	16	17	86	86	87	86
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth										
30	Medium - June 2008	$45 to $179	31	31	58	42	86	83	53	72
31	High - June 2008	$45 to $179	28	14	21	19	86	86	66	78
Sensitivity Case - High Cost Outcome										
33	High - June 2008	$100	24	8	9	11	85	85	86	85
Sensitivity Cases - Clean Base-Load Generation Availability										
34	Medium - June 2008	$45	32	27	44	35	86	85	86	86
35	High - June 2008	$45	30	17	16	19	86	86	83	85
36	Medium - June 2008	$70	19	29	48	34	86	73	67	73
37	High - June 2008	$70	25	10	6	12	86	82	73	79
Sensitivity Cases - High Plant Construction Costs										
38	Medium - June 2008	$45	33	32	48	38	86	87	88	87
39	High - June 2008	$45	24	10	11	13	85	80	84	82
Sensitivity Case - System-wide Oregon CO2 Reduction Targets										
40	Medium - June 2008	Hard Cap	30	11	10	15	86	77	67	75
Sensitivity Cases - Planning Reserve Margin, 15%										
41	Medium - June 2008	$45	31	26	41	33	86	86	86	86
42	Medium - June 2008	$70	29	27	43	34	86	72	68	73
43	Medium - June 2008	$100	28	31	48	37	86	52	36	52
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)										
44	Medium - Oct 2008	$8, C&T	35	33	49	40	86	87	88	87
45	Medium - Oct 2008	$8, C&T	34	33	58	43	85	86	88	87
Sensitivity Case - Class 3 DSM for Peak Load Reduction										
48	Medium - June 2008	$45	32	29	47	37	86	86	86	86

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

Sensitivity Case Results

CO2 Tax Real Cost Escalation and Demand Response

Cases 30 and 31 were designed to test a real escalating CO_2 tax and assumed decrease in load growth attributable to the price response. The CO_2 tax begins in 2013 and is increased at a real straight-line escalation rate resulting in $7.86/ton increases per year starting in 2014. Load growth is maintained at a medium level through 2020, after which the growth converts to a low forecast for the remainder of the simulation period.

For the two cases, all factors were held constant with the exception of the gas price forecast used: case 30 was based on the June 2008 medium gas price while case 31 was based on the June 2008 high gas price forecast. The case 30 portfolio included 5,498 MW of wind added by 2028, a nuclear plant in 2025, and four carbon capture and sequestration plants in 2025, including an IGCC resource. The case 31 portfolio included more wind and front office transactions, but excluded the IGCC resource.

The PVRR for case 31 was $989 million lower than case 30, an unintuitive result. Several factors contributed to this PVRR difference:

- The 466 MW Utah IGCC with CCS unit added in the case 30 portfolio was not included in case 31. Instead, higher on-peak spot purchases and DSM programs costs were incurred in case 31.
- Case 31 included 750 MW more wind than case 30 in the first ten years. As a result of the additional wind, existing station fuel costs in case 31 were $1.1 billion lower than in case 30.
- While the capital costs for case 31 were $2.4 billion higher than in case 30, the difference was offset by higher spot market sales in case 31.

Normally the System Optimizer model will build to the 12% planning reserve margin level; however, it may exceed that if it is economic to add extra capacity and sell excess energy to the market. For example, in cases 30 and 31, the model added resources in excess of the planning reserve margin in 2025 through 2028 with the addition of a 3,200 MW nuclear plant. Significant excess energy is sold to market, contributing to $27.6 and $30.0 billion PVRR reductions for cases 30 and 31, respectively

Early Clean Base-load Resource Availability

Cases 34 through 37 were designed to test early availability of clean base-load generation resources by allowing System Optimizer to select such resources as early as 2020 rather than 2025 as specified for all other case definitions. Cases 34 and 35 were specified with a $45/ton CO_2 tax and varying gas price forecasts (medium and high June 2008), while cases 36 and 37 were based on a $70 CO_2 tax with the same gas price forecasts.

For cases 34 and 35, no clean base-load technology was selected; however, the high gas price forecast used in case 35 caused the model to select about 1,000 MW of additional wind in the west and a 600 MW pulverized coal plant in Utah. Case 34 favored front office transactions.

For cases 36 and 37 (both with the \$70 CO_2 tax), three clean coal resources were selected in 2020. For case 37, the model also selected a 3,200 MW nuclear station in 2020 as an alternative to market purchases in the out years. The PVRR for case 37 is about \$2.3 billion lower than case 36, and this cost relationship exists between cases 34 and 35 as well. As indicated above, the cost difference is attributable to the model selling excess energy to the market.

High Construction Costs

For cases 38 and 39, resource construction costs were uniformly increased by 20 percent. Both were based on a \$45 CO_2 tax, medium load growth, and medium and high gas price forecasts, respectively.

Comparing case 38 to case 8 (which used the same input assumptions except for construction costs) indicates that the uniform percentage cost increase caused the model to select additional DSM programs along with dispatching existing units more often. Similarly, a comparison between cases 39 and 14 indicate that the construction cost increase, combined with a higher gas price forecast, caused the model to build about 3,000 MW less wind in case 39 than for case 14. The reduced wind build in case 39 was a major contributor to the lower PVRR relative to that for case 14 (a \$5.16 billion difference). In addition, the Utah IGCC unit picked in case 14 was not chosen in case 39. For case 39, the model preferred to buy from the market and relied more heavily on growth resources in the out years. In case 39, units were not dispatched as often as in case 14 and there was consequently less power to sell to the market.

Carbon Dioxide Emissions Hard Cap

Case 40 was designed to determine the optimal resource mix given a system-wide CO_2 emissions hard cap patterned after the Oregon CO_2 reduction targets from House Bill 3543 (10 percent below 1990 levels by 2020, and at least 75% below 1990 levels by 2050). The specific allowances per year reflected in the System Optimizer model are reported in Table 8.4. The cap is assumed to go into effect beginning in 2013. With these system emission constraints in place, the model optimizes the resource mix such that the system-wide average emissions stay at or below the annual caps.

Table 8.4 – Hard Cap CO_2 Emission Allowances

Year	Hard Cap CO2 Allowances (Million Short Tons)
2009	53.484
2010	53.484
2011	55.192
2012	56.077
2013	54.244
2014	52.412
2015	50.579
2016	48.746
2017	46.913
2018	45.081
2019	43.248
2020	41.415
2021	40.418
2022	39.421
2023	38.424

Year	Hard Cap CO2 Allowances (Million Short Tons)
2024	37.427
2025	36.430
2026	35.433
2027	34.436
2028	33.439

For this sensitivity study, front office transactions and growth resources were assigned a proxy CO_2 emission rate. The rate is that for a Utah combined-cycle gas plant (F type 2x1), reflecting a presumed long term reduction in the WECC CO_2 footprint attributable to the penetration of gas, wind and other renewable resources in the resource stack. Additionally, the June 2008 $0 CO_2 tax forward price forecasts were used to ensure that the model's capacity expansion solution was constrained by the hard cap only, and not impacted by CO_2 costs reflected in market prices.

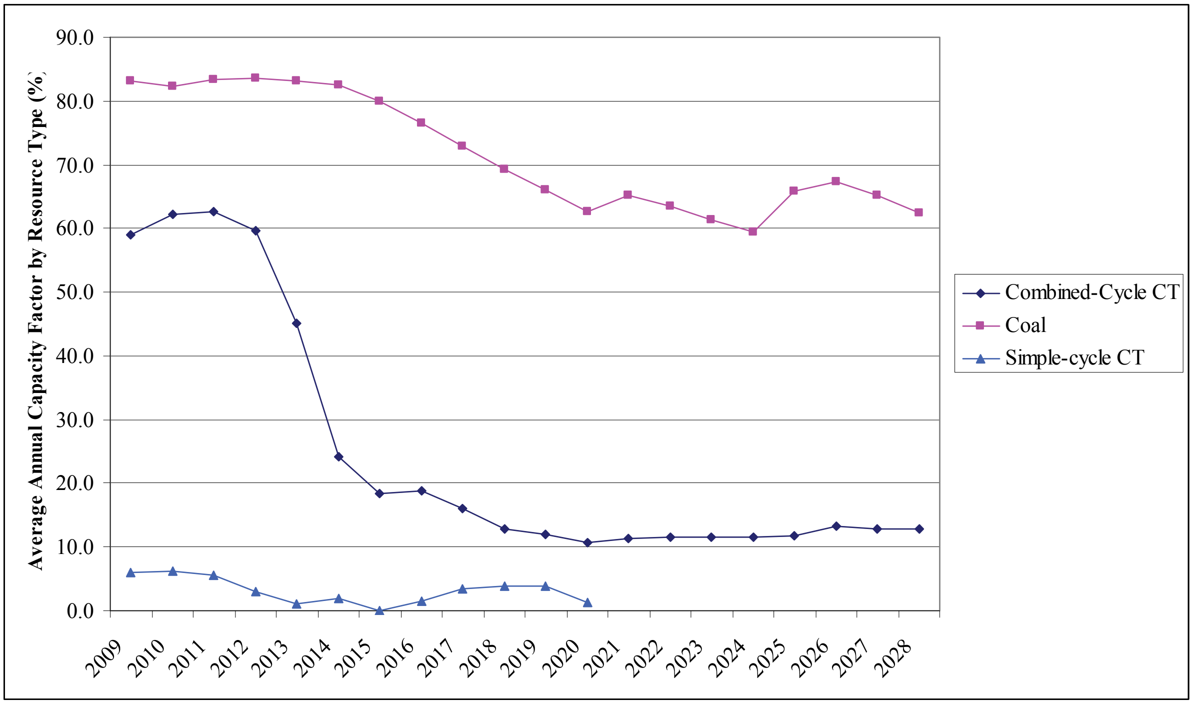
Table 8.5 compares the total emissions generated in case 40 to the three core cases with medium load, medium gas forecasts (Case 8, 17, and 24). The results indicate that the hard cap portfolio is most comparable to the $70 CO_2 tax portfolio, having total cumulative emissions of 896 and 931 million tons, respectively.

Table 8.5 – Portfolio Comparison, System Optimizer Total CO_2 Emissions by Year

Year	CO2 emissions (Millions Short Tons)			
	Case 40	Case 8	Case 17	Case 24
	System Hard Cap	$45/ton CO2 tax	$70/ton CO2 Tax	$100/ton CO2 Tax
2009	54.0	54.5	54.4	54.4
2010	53.7	54.0	53.8	53.6
2011	54.5	54.1	54.0	53.6
2012	56.1	54.2	53.6	52.5
2013	54.2	54.1	51.5	46.3
2014	52.4	53.4	49.3	43.9
2015	50.6	54.3	47.8	38.3
2016	48.7	54.2	44.5	33.7
2017	46.9	55.3	47.6	35.7
2018	45.1	55.3	50.0	37.7
2019	43.2	55.7	50.5	37.7
2020	41.4	55.6	50.9	37.9
2021	40.4	54.1	50.0	37.6
2022	39.4	54.1	49.2	36.3
2023	38.4	54.0	47.9	32.6
2024	37.4	54.0	45.8	27.1
2025	36.4	53.6	36.2	12.3
2026	35.4	52.7	33.0	11.9
2027	34.4	52.3	30.8	11.3
2028	33.4	51.9	29.8	10.8
Cumulative Total	896.4	1081.3	930.6	705.4

With the combination of medium June 2008 market prices and the hard cap, a significant reduction in combined-cycle gas plant capacity factors happens from 2013 through 2015, followed by a gradual decrease through 2020. Figure 8.1 compares the average annual capacity factors for combined-cycle, coal, and simple-cycle combustion turbine resources reflected in the model. Capacity factors for certain coal plants begin to drop off in 2015, while others are unaffected, reflecting the relative dispatch cost differences among the plants. As noted earlier in the chapter, the impact of CO_2 costs on plant dispatch cannot be assessed in isolation from fuel prices; utilization of thermal resource types in response to CO_2 costs will vary considerably based on the fuel price forecasts used for the simulations.

Figure 8.1 – Average Annual Capacity Factors by Resource Type, CO_2 Hard Cap Portfolio



A number of current IRP model limitations come into play for analyzing a hard cap scenario. First, the System Optimizer model does not allow emission rates to be assigned to spot market balancing transactions. This limitation is being addressed in an enhanced version of the model being developed for PacifiCorp by the model vendor. Second, the Planning and Risk model is limited in that hard caps cannot be directly enforced. To simulate the effect of a hard cap, the shadow cost for the last ton of incremental emissions calculated from System Optimizer can be entered into the Planning and Risk model. PacifiCorp is in the process of experimenting and validating this work-around approach. The test simulation resulted in annual CO_2 emissions that were consistently below the hard cap. The stochastic costs results for the test simulation are as follows: mean PVRR of $41.0 billion, upper-tail mean PVRR of $76.4 billion, and production cost standard deviation of $11.7 billion.

Alternative Renewable Policy Assumptions

Case 44 is designed with a System Optimizer constraint that imposes a system-wide renewable generation requirement that reaches 25 percent of system load by 2028. Case 44 parallels case 8 in terms of other input assumptions; i.e., an \$8 CO_2 tax and medium June 2008 gas and electricity prices.

In order to satisfy the higher RPS requirement, the model selected a large amount of wind and some geothermal resources, especially in the mid and later years of the simulation period. With nearly 6,000 MW of wind resources built, this scenario attributes a relatively small PVRR to sales of clean energy to markets.[47]

The second alternative renewable policy scenario was established to determine the best resource mix without the renewable production tax credit after 2012. Case 45 was created from case 44 with the base case RPS requirement, but the costs of resources qualifying for the PTC were adjusted to remove the incentive after 2012. Without the PTC, the model selected:

- No wind resources after 2012
- A west geothermal resource in 2023
- An IC Aero SCCT in 2016 instead of wind resources
- More growth resource capacity in the out years

STOCHASTIC SIMULATION RESULTS - CANDIDATE PORTFOLIOS

This section presents stochastic cost, stochastic supply reliability risk, and capital cost performance results for the 21 portfolios that constitute the group from which the preferred portfolio was selected. For the stochastic cost measures, results are first shown for the three individual CO_2 tax simulations, along with the straight average across the CO_2 tax results. The section concludes with tables that show the stochastic cost results as probability-weighted values. These values reflect \$5/ton increments of the expected value (EV) CO_2 tax, ranging from \$20/ton to \$70/ton.

Stochastic Mean PVRR

Table 8.6 reports the stochastic mean PVRR for each of the candidate portfolios by CO_2 tax level, along with average values and associated rankings. Cases 8, 5, and 9 rank the highest based on the average of the CO2 tax results.

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[47] The cost results presume a regulatory world with both a \$45/ton CO_2 tax and an aggressive RPS requirement. In this situation, the markets would be flooded with excess clean energy, driving market prices down. This dynamic is not captured in the scenario. Also, the reliability impacts and costs of such large amounts of wind being added to the system are not factored into the IRP simulations.

Table 8.6 – Stochastic Mean PVRR by Candidate Portfolio

Case	CO2 Tax Level, Million Dollars (2009$)				Rank
	$0/ton	$45/ton	$100/ton	Average	
1	21,873	39,893	61,299	41,022	10
2	21,642	39,542	60,098	40,427	4
3	24,844	40,745	57,781	41,123	11
5	22,417	39,289	58,700	40,136	2
8	23,092	39,244	57,311	39,882	1
9	22,532	39,398	58,800	40,244	3
10	23,723	39,872	58,198	40,598	6
11	25,664	41,035	57,496	41,398	12
14	27,620	42,481	57,954	42,685	16
17	25,267	40,134	56,369	40,590	5
18	25,092	40,185	56,822	40,700	7
19	25,600	40,513	56,870	40,994	9
20	28,412	42,127	56,620	42,386	15
22	29,751	43,576	57,813	43,713	20
24	30,393	43,496	57,094	43,661	19
25	27,178	41,317	56,419	41,638	13
26	30,056	43,417	57,485	43,653	18
27	30,367	43,477	57,105	43,650	17
29	32,601	45,626	59,042	45,757	21
46	23,336	40,975	61,146	41,819	14
47	22,345	40,058	60,378	40,927	8

Table 8.7 reports the incremental mean PVRR associated with imposing the $45/ton and $100/ton CO_2 taxes, as well as the average cost for the two tax levels. Table 8.8 reports the net power cost (variable cost less market sales revenue) and fixed cost by portfolio for the three CO_2 tax simulations.

Table 8.7 – Incremental Mean PVRR by CO_2 Tax Level

Case	Incremental Mean PVRR (Million $)		
	$45/ton	$100/ton	Average
1	18,019	39,426	28,723
2	17,900	38,456	28,178
3	15,901	32,937	24,419
5	16,872	36,284	26,578
8	16,152	34,219	25,186
9	16,866	36,268	26,567
10	16,149	34,476	25,312
11	15,371	31,831	23,601
14	14,861	30,334	22,597
17	14,867	31,102	22,984
18	15,093	31,730	23,411
19	14,913	31,270	23,092
20	13,715	28,208	20,962
22	13,825	28,062	20,943

Case	Incremental Mean PVRR (Million $)		
	$45/ton	$100/ton	Average
24	13,103	26,700	19,902
25	14,139	29,241	21,690
26	13,361	27,429	20,395
27	13,110	26,738	19,924
29	13,025	26,440	19,733
46	17,639	37,811	27,725
47	17,713	38,032	27,873

Table 8.8 – PVRR Net Power Costs and Fixed Costs by CO_2 Tax Level

Case	$0/ton CO2 Tax				$45/ton CO2 Tax				$100/ton CO2 Tax			
	Net Power Cost (Bil$)	Rank	Fixed Cost (Bil$)	Rank	Net Power Cost (Bil$)	Rank	Fixed Cost (Bil$)	Rank	Net Power Cost (Bil$)	Rank	Fixed Cost (Bil$)	Rank
1	20.0	21	1.8	1	38.1	21	1.8	1	59.5	21	1.8	1
2	18.3	18	3.4	2	36.2	20	3.4	2	56.7	20	3.4	2
3	14.1	9	10.7	12	30.0	10	10.7	12	47.1	11	10.7	12
5	18.3	20	4.1	3	35.2	17	4.1	3	54.6	17	4.1	3
8	16.8	14	6.3	7	33.0	14	6.3	7	51.0	14	6.3	7
9	18.3	19	4.2	5	35.2	16	4.2	5	54.6	16	4.2	5
10	17.4	15	6.4	8	33.5	15	6.4	8	51.8	15	6.4	8
11	13.9	8	11.8	13	29.2	9	11.8	13	45.7	9	11.8	13
14	12.7	5	14.9	15	27.6	7	14.9	15	43.0	7	14.9	15
17	15.7	11	9.6	10	30.5	11	9.6	10	46.8	10	9.6	10
18	16.1	13	9.0	9	31.2	13	9.0	9	47.8	13	9.0	9
19	15.8	12	9.8	11	30.7	12	9.8	11	47.1	12	9.8	11
20	13.2	7	15.2	16	26.9	6	15.2	16	41.4	6	15.2	16
22	12.1	1	17.6	18	25.9	4	17.6	18	40.2	4	17.6	18
24	12.4	4	18.0	20	25.5	3	18.0	20	39.1	2	18.0	20
25	14.1	10	13.0	14	28.3	8	13.0	14	43.4	8	13.0	14
26	13.1	6	17.0	17	26.4	5	17.0	17	40.5	5	17.0	17
27	12.4	3	18.0	19	25.5	2	18.0	19	39.1	3	18.0	19
29	12.2	2	20.4	21	25.3	1	20.4	21	38.7	1	20.4	21
46	17.9	16	5.4	6	35.6	18	5.4	6	55.7	18	5.4	6
47	18.2	17	4.1	4	35.9	19	4.1	4	56.2	19	4.1	4

Risk-adjusted PVRR

As discussed in Chapter 7, risk-adjusted PVRR is calculated as the stochastic mean PVRR plus five percent of the 95th percentile PVRR, with the latter term representing a cost premium reflecting the tail risk for the portfolio. This measure constitutes 45 percent of the overall composite portfolio preference score for each candidate portfolio.

Table 8.9 reports the risk-adjusted PVRR values for each of the portfolios by CO_2 tax level, along with average values and associated rankings. Cases 8, 5, and 9 rank the highest in line with the stochastic mean PVRR values reported in Table 8.3. Figure 8.2 shows the range of risk-adjusted PVRRs for each portfolio by CO_2 tax level, matched up with the amount of incremental wind capacity included. It is apparent from the chart that the variation in risk-adjusted PVRR across the CO_2 tax levels generally decreases as the amount of portfolio wind capacity increases.

Figures 8.3 through 8.7 show capacity by resource type for each portfolio, ranked by risk-adjusted PVRR averaged across the CO_2 tax simulations. The resource types include wind, energy efficiency, average annual front office transactions, clean base load coal, and IC aero SCCT resources. These charts indicate the correlation between the amount of primary resource type added to the portfolios and the risk-adjusted cost. As can be seen from Figure 8.3, the positive correlation between risk-adjusted PVRR and amount of wind capacity added is clearly evident. Similarly the negative correlation between risk-adjusted PVRR and the volume of front office transactions is evident in Figure 8.4.

Table 8.9 – Risk-adjusted PVRR by Portfolio

Case	CO2 Tax Level, Million Dollars (2009$)			Average	Rank
	$0/Ton	$45/Ton	$100/Ton		
1	23,992	43,093	66,090	44,392	12
2	23,506	42,492	64,586	43,528	4
3	26,610	43,555	61,952	44,039	9
5	24,365	42,270	63,154	43,263	2
8	24,942	42,138	61,628	42,903	1
9	24,489	42,387	63,261	43,379	3
10	25,676	42,815	62,585	43,692	6
11	27,472	43,856	61,646	44,324	11
14	29,422	45,340	62,046	45,603	16
17	27,173	43,021	60,574	43,589	5
18	27,009	43,093	61,077	43,726	7
19	27,533	43,427	61,111	44,024	8
20	30,314	44,957	60,666	45,312	15
22	31,599	46,442	61,886	46,642	20
24	32,292	46,363	61,088	46,581	18
25	29,107	44,193	60,544	44,615	13
26	31,986	46,290	61,528	46,602	19
27	32,251	46,338	61,087	46,559	17
29	34,596	48,571	63,133	48,767	21
46	25,255	43,973	65,681	44,970	14
47	24,233	43,022	64,885	44,047	10

Figure 8.2 – Risk-adjusted PVRR Range and Wind Nameplate Capacity by Portfolio

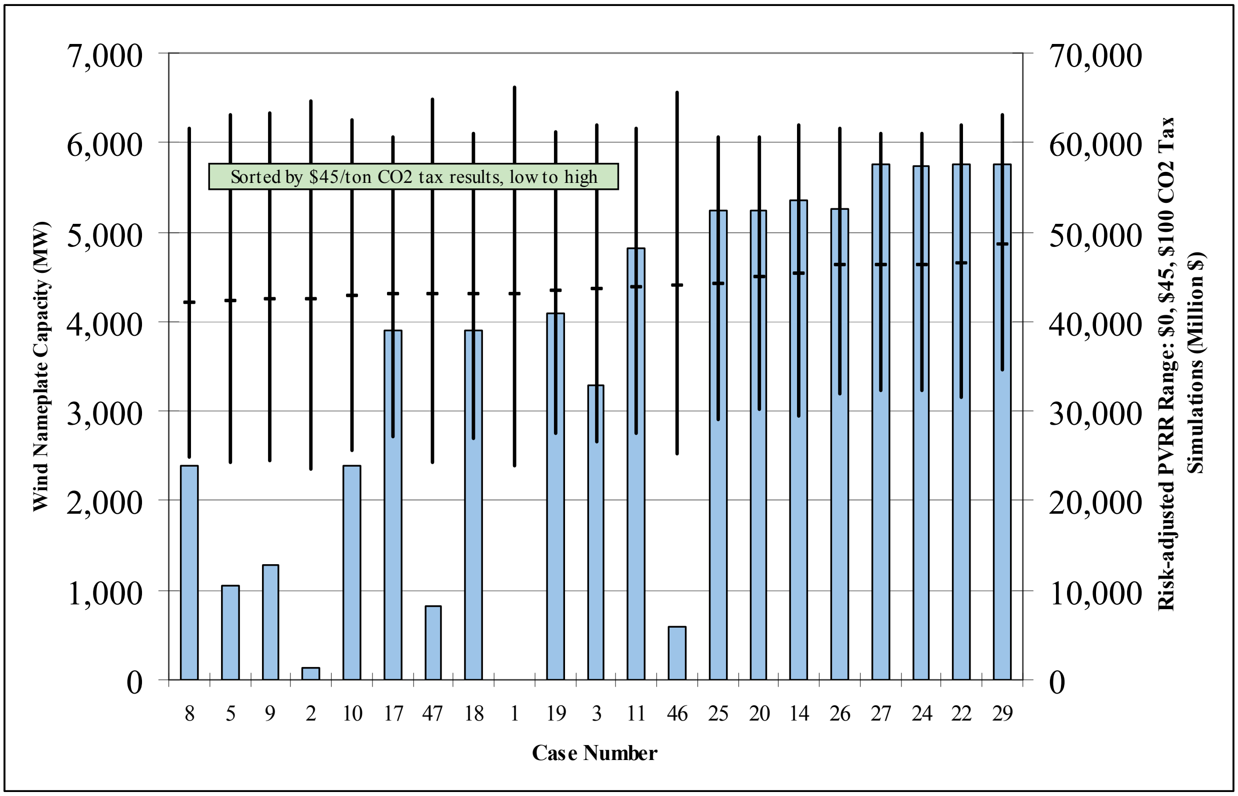


Figure 8.3 – Wind Capacity for Portfolios Ranked by Risk-adjusted PVRR

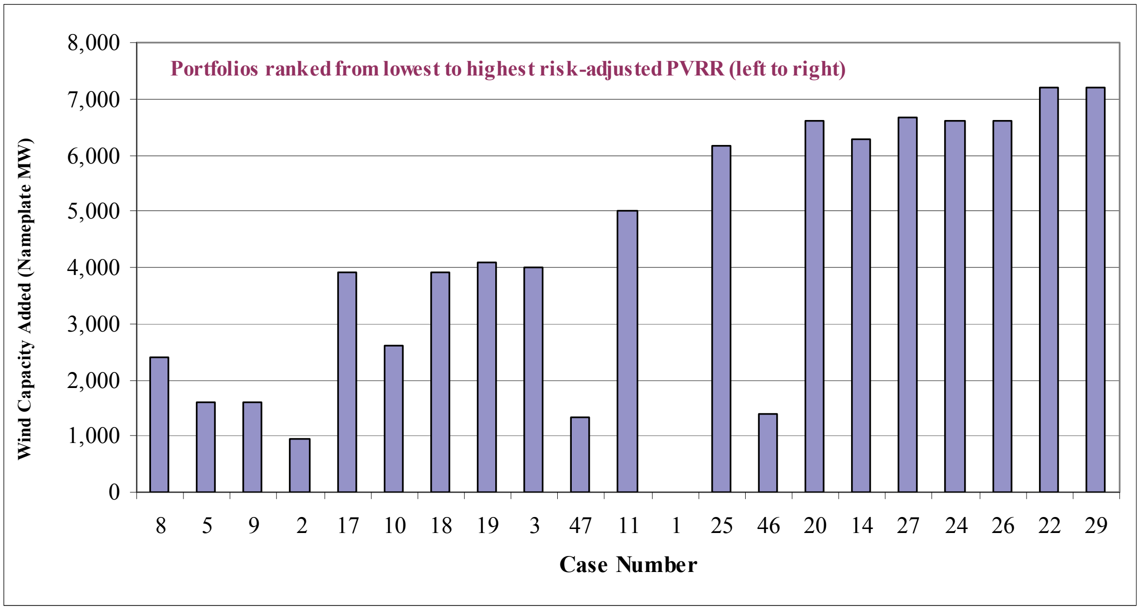


Figure 8.4 – Energy Efficiency Capacity for Portfolios Ranked by Risk-adjusted PVRR

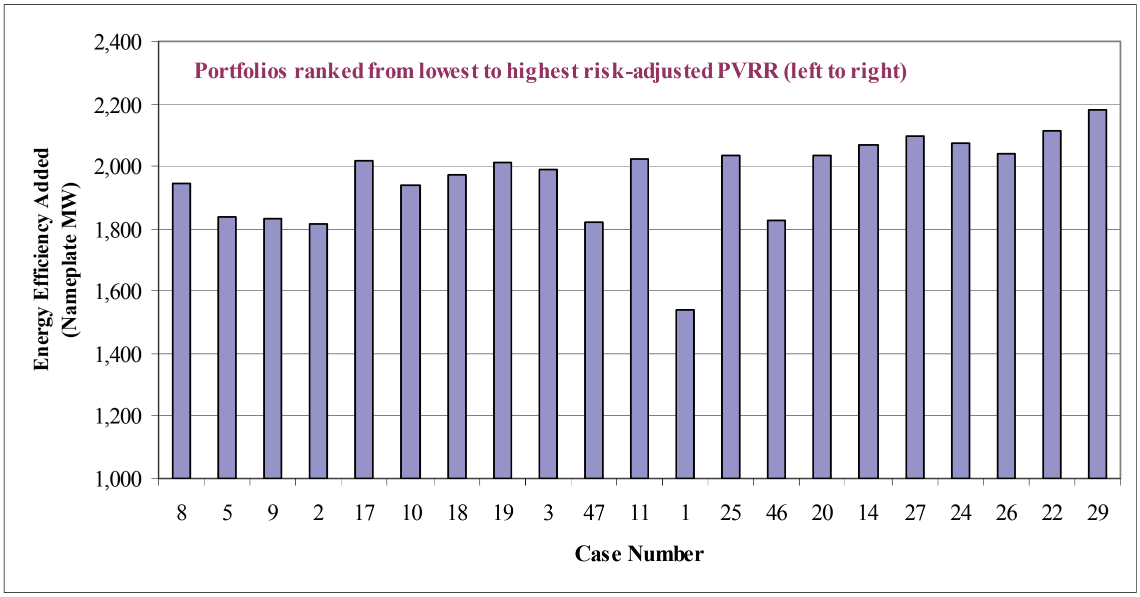


Figure 8.5 – Annual Average Front Office Transaction Capacity for Portfolios Ranked by Risk-adjusted PVRR

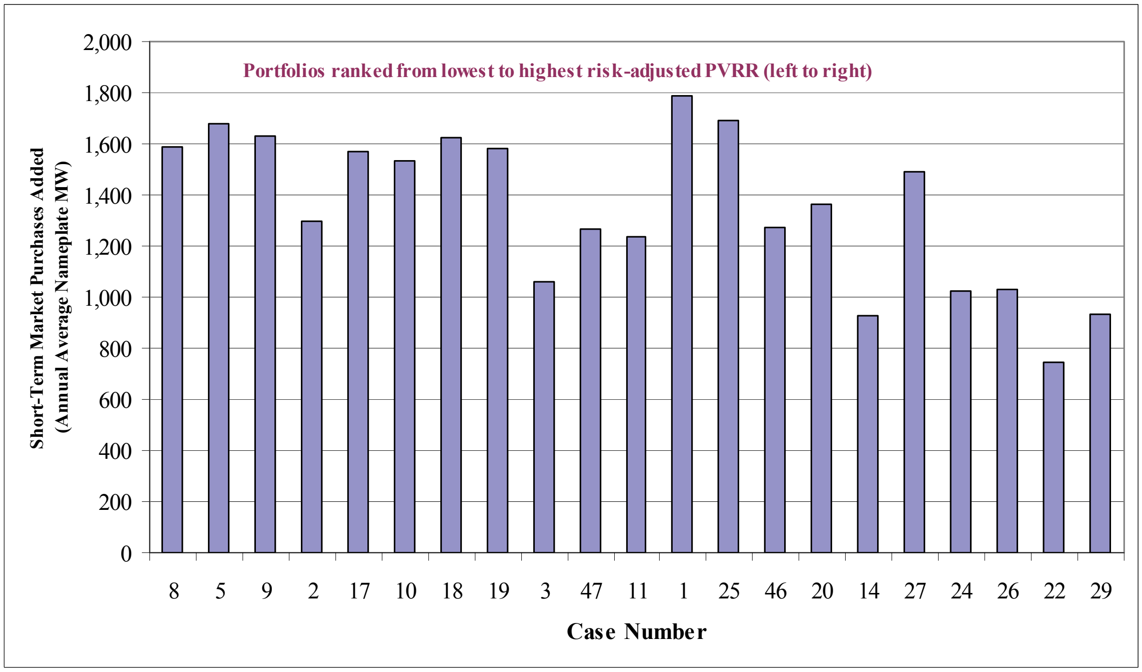


Figure 8.6 – Clean Base Load Coal Capacity for Portfolios Ranked by Risk-adjusted PVRR

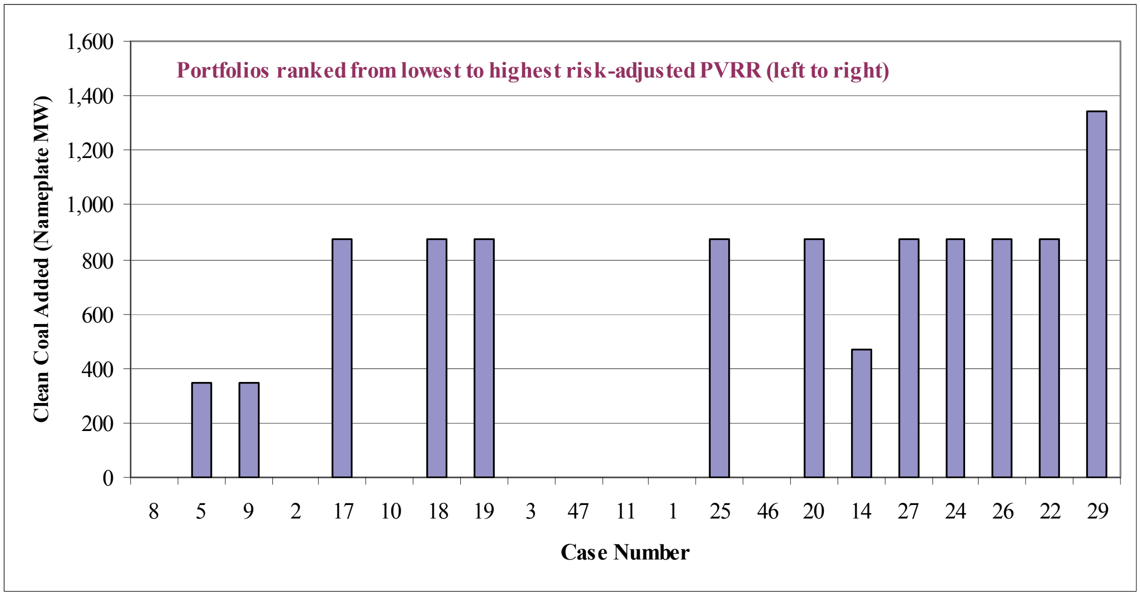
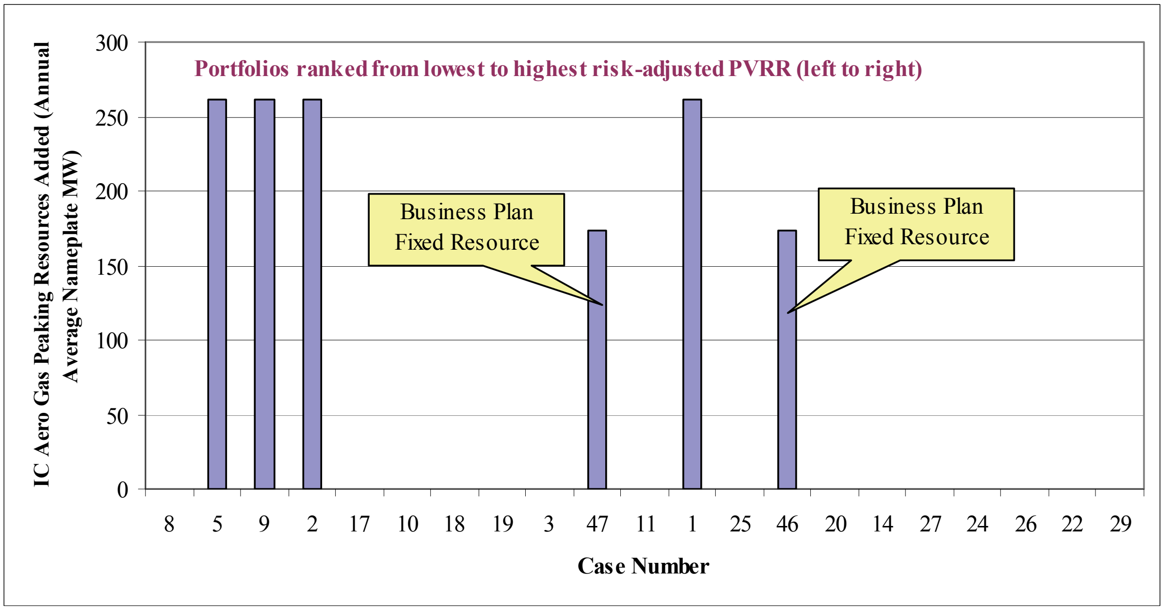


Figure 8.7 – IC Aeroderivative SCCT Capacity for Portfolios Ranked by Risk-adjusted PVRR



Customer Rate Impact

The portfolio customer rate impacts for each CO_2 tax simulation, and averaged across the simulations, are reported in Table 8.10. This measure is given a 20 percent weight for determining the overall portfolio preference scores.

With no CO_2 tax, the portfolios for cases 1 and 2 perform the best due to the lack of wind investment. Case 1, which has the lowest rate impact, has no wind additions other than the firm planned resources in 2009 and 2010. Case 2, which ranked second, has only 338 MW of wind added by 2018, but includes a 600 MW super-critical coal plant in 2018. Under the $45 CO_2 tax, the top performers are the portfolios for cases 9 and 5. Case 9 has slightly more wind resources than case 5 (by 230 MW) and less front office transactions. Under the $100 CO_2 tax, the top performers are cases 20 and 17. Case 20 relies on a nuclear plant in 2025 and more wind than for case 17.

When averaging the results across the CO_2 tax levels, cases 9 and 5 fare the best; they rank first and second, respectively.

Table 8.10 – Customer Rate Impacts by Portfolio

Case	CO_2 Tax Level (2009$)			Average	Rank
	$0/ton	$45/ton	$100/ton		
1	2.82	6.28	10.16	6.42	8
2	2.89	6.31	10.06	6.42	7
3	3.49	6.58	9.74	6.61	14
5	2.95	6.11	9.54	6.20	2
8	3.08	6.19	9.48	6.25	5
9	2.93	6.09	9.52	6.18	1
10	3.24	6.31	9.64	6.40	6
11	3.34	6.22	9.11	6.22	3
14	4.09	6.97	9.80	6.95	16
17	3.48	6.22	9.03	6.24	4
18	3.61	6.41	9.33	6.45	9
19	3.66	6.43	9.28	6.46	10
20	4.24	6.62	8.92	6.59	13
22	4.78	7.30	9.70	7.26	18
24	5.22	7.51	9.70	7.48	20
25	3.95	6.57	9.20	6.58	12
26	5.09	7.41	9.66	7.39	19
27	4.99	7.19	9.27	7.15	17
29	5.71	7.96	10.07	7.91	21
46	3.16	6.55	10.22	6.64	15
47	2.99	6.39	10.09	6.49	11

Cost Exposure under Alternative Carbon Dioxide Tax Levels

As discussed in Chapter 7, cost exposure is the difference between a portfolio's risk-adjusted PVRR and the risk-adjusted PVRR of the best-performing portfolio for a given CO_2 tax level. Portfolio performance under this measure is gauged by the size of the worst loss that could be realized under the three CO_2 tax levels if the chosen portfolio turns out to not be the optimal one based on risk-adjusted PVRR. This measure was assigned a 15 percent weight for determining the overall portfolio preference scores.

Table 8.11 presents the cost exposure results for the CO_2 tax simulations, with no probability weights applied. As indicated in the table, the potential cost exposure is large for portfolios built in response to an extreme CO_2 tax value, and where the realized CO_2 tax turns out to be at the other extreme. The cost exposures range from $30 million for case 17 under a realized $100/ton tax, to $11 billion for case 29 given no CO_2 tax. (Note that portfolios with no cost exposure value reported have the lowest cost at that CO_2 tax level.)

To be consistent with the probability-weighted approach used to rank portfolio performance, the maximum loss values are probability-weighted as well.

Table 8.11 – Portfolio Cost Exposures for Carbon Dioxide Tax Outcomes

	CO2 Tax Level, Million Dollars (2009$)				
Case	**$0/ton**	**$45/ton**	**$100/ton**	**Maximum Loss**	**Rank**
1	486	956	5,546	5,546	13
2	-	354	4,042	4,042	10
3	3,104	1,417	1,408	3,104	5
5	859	132	2,610	2,610	3
8	1,436	-	1,084	1,436	1
9	983	249	2,717	2,717	4
10	2,170	678	2,040	2,170	2
11	3,965	1,718	1,102	3,965	8
14	5,916	3,202	1,502	5,916	15
17	3,667	883	30	3,667	7
18	3,503	955	533	3,503	6
19	4,026	1,290	566	4,026	9
20	6,808	2,819	122	6,808	16
22	8,093	4,304	1,342	8,093	17
24	8,786	4,225	543	8,786	20
25	5,601	2,055	-	5,601	14
26	8,480	4,152	984	8,480	18
27	8,745	4,200	543	8,745	19
29	11,090	6,433	2,588	11,090	21
46	1,749	1,835	5,137	5,137	12
47	727	885	4,341	4,341	11

Portfolio Capital Costs

Figures 8.8 and 8.9 show the capital costs for each portfolio, expressed on a net present value basis for costs accrued for 2009-2018 and 2009-2028, respectively. (The 2009-2018 capital cost measure was assigned a five percent weight for determining the portfolio preference scores.)

The portfolios with the lowest capital costs are for cases 1, 2, and 5. Case 1, with a capital cost of $0.5 billion, relies more heavily on market purchases, distributed generation, and Class 1 DSM than the other low capital cost portfolios, and reflects no incremental wind investment past 2010.

In contrast, the high-cost portfolios—such as cases 29, 22, 27, and 24—reflect large investments in wind, clean coal, and nuclear plants to mitigate the CO_2 tax liabilities.

Figure 8.8 – Portfolio Capital Costs, 2009-2018

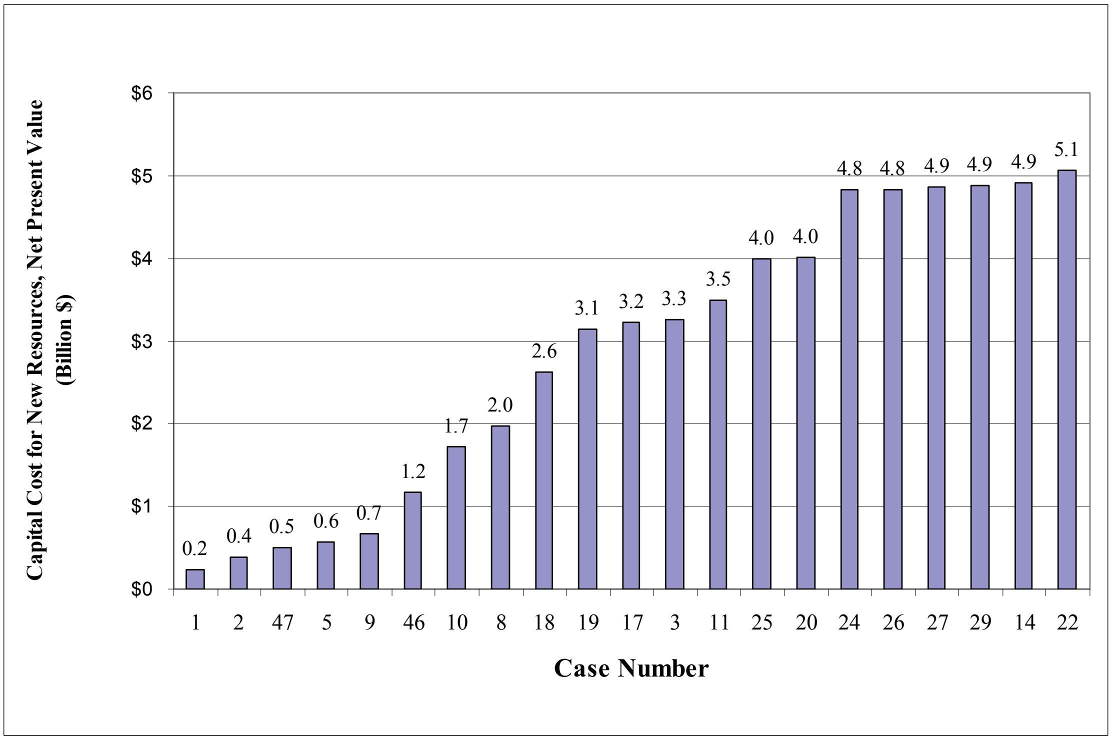
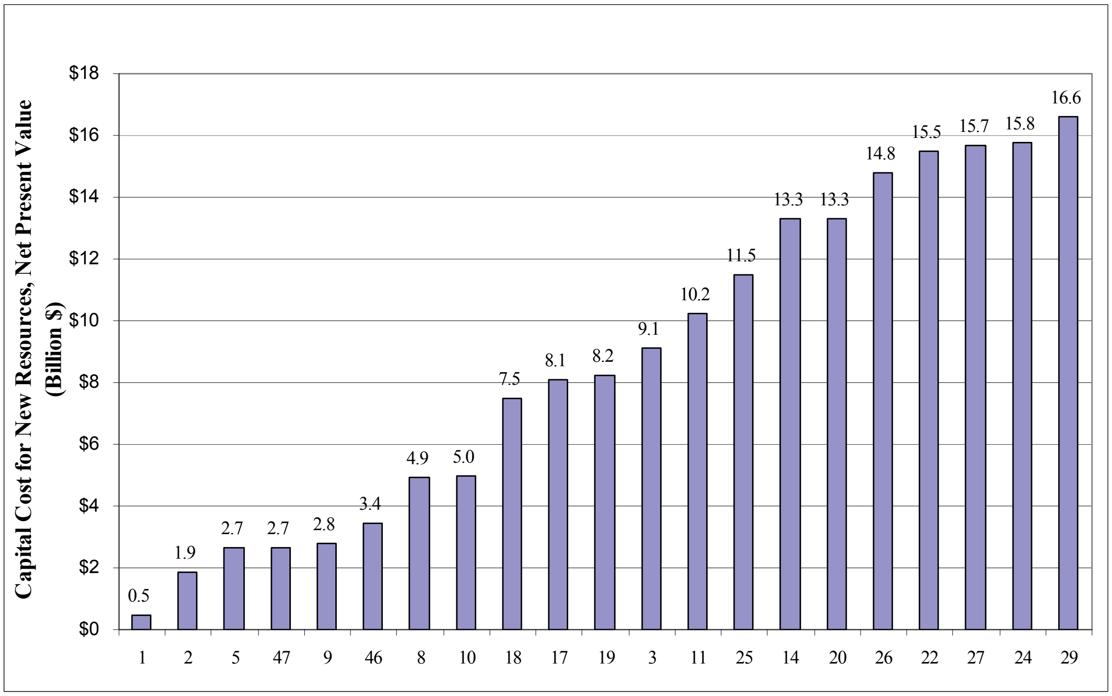
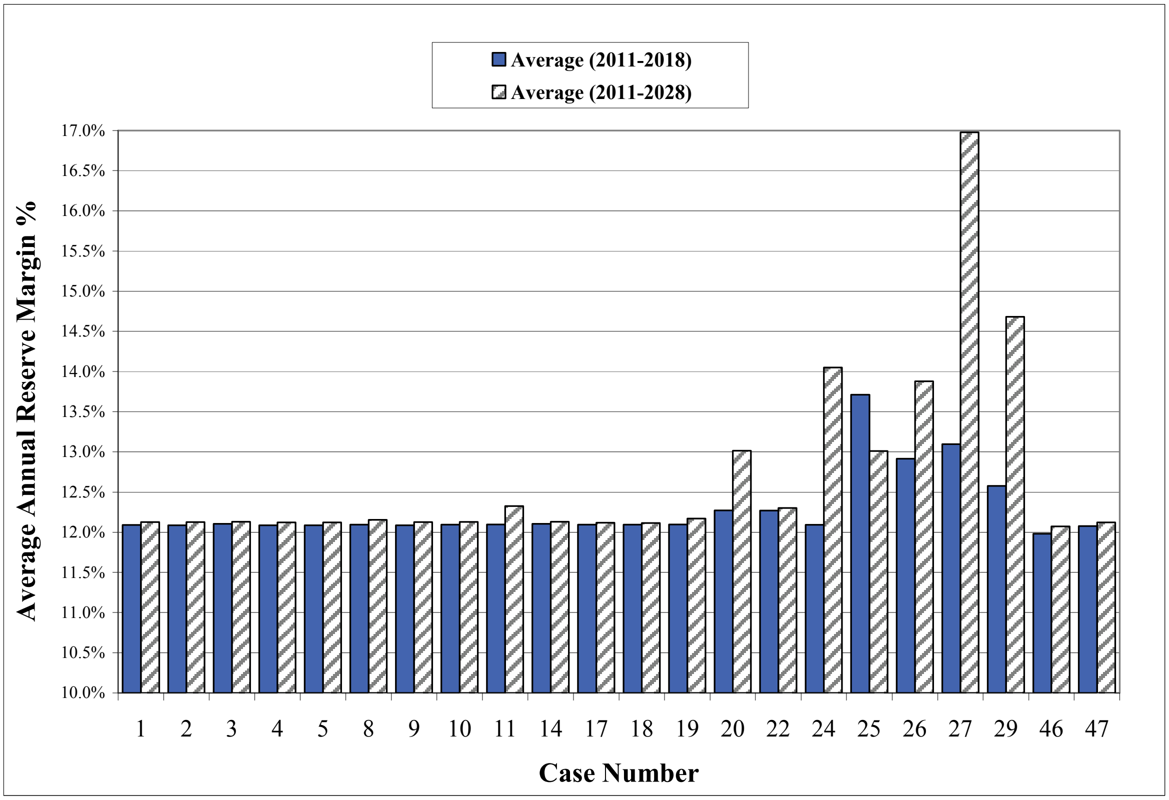


Figure 8.9 – Portfolio Capital Costs, 2009-2028



The impact of such investments on capacity planning reserve margins, particularly in the out years, is indicated in Figure 8.10. This figure shows average annual reserve margins for 2011 to 2018 (reflecting the start of the system capacity short position) as well as for 2011 to 2028. The association between extensive clean generation investment and excess planning reserve margins is clearly seen with margins far exceeding the 12 percent requirement reflected in the model.[48]

Figure 8.10 – Average Annual Planning Reserve Margins



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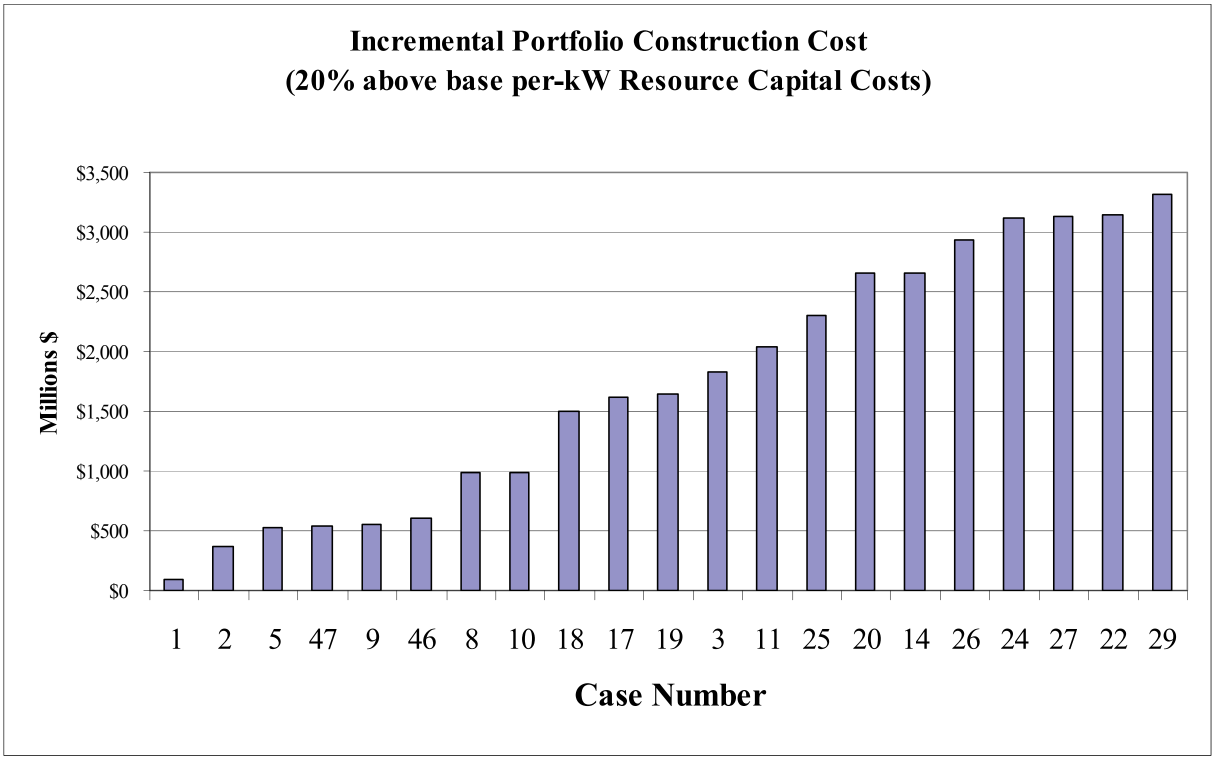
[48] The 2011-2028 average annual planning reserve margins for case 11, which was based on a $45/ton CO_2 tax, is higher than for the other core cases with this tax level. Unlike the other $45 tax cases, case 11 was modeled with high gas prices. This case experienced greater west-east transfers than the other cases for 2026-2028, supported by a relatively larger amount of growth resources and front office transactions on the west side.

Figure 8.11 shows the impact on portfolio capital costs given a 20 percent increase in the per-kilowatt capital cost for all resources.

Figure 8.11 – Incremental Portfolio Capital Costs (20% increase from Base per-kW values)



Upper-tail Mean PVRR

Table 8.12 reports the upper-tail mean PVRR results for the individual CO_2 tax simulations and the average.

Cases 22 and 14 perform the best. Case 22 includes both pulverized coal and nuclear plants in response to a $70/ton CO_2 tax and high gas/electricity prices. Case 14 also includes pulverized coal as well as an IGCC plant in 2025. Both portfolios feature heavy reliance on wind resources (7,200 MW for case 22 and 6,300 MW for case 14), and consequently rely on less front office transactions and gas plant dispatch.

Table 8.12 – Upper-tail Mean PVRR by Portfolio

Case	CO2 Tax Level, Million Dollars (2009$)				Rank
	$0/ton	$45/ton	$100/ton	Average	
1	57,487	80,005	114,973	84,155	21
2	51,169	73,646	107,193	77,336	16
3	44,084	65,519	94,991	68,198	5

Case	**CO2 Tax Level, Million Dollars (2009$)**				**Rank**
	$0/ton	**$45/ton**	**$100/ton**	**Average**	
5	53,047	74,487	106,969	78,168	19
8	49,843	70,581	101,048	73,824	14
9	53,347	74,736	107,163	78,415	20
10	52,335	72,023	102,956	75,771	15
11	44,638	65,642	94,453	68,244	6
14	44,778	65,453	93,021	67,751	2
17	49,328	68,766	96,941	71,678	11
18	50,209	69,834	98,591	72,878	13
19	50,320	69,705	98,022	72,682	12
20	46,767	66,084	92,486	68,446	7
22	45,569	65,404	91,170	67,381	1
24	46,980	65,939	91,142	68,020	4
25	48,112	66,967	94,182	69,754	10
26	47,587	66,665	92,520	68,924	8
27	46,732	65,701	90,907	67,780	3
29	48,734	67,670	92,365	69,590	9
46	52,224	74,442	107,516	78,061	18
47	51,559	73,905	107,252	77,572	17

The following charts present the megawatt capacities for the portfolios ranked by upper-tail mean PVRR, focusing on the resource types most consequential for determining upper-tail cost risk. Figures 8.12 and 8.13 show the portfolio wind and energy efficiency capacities, indicating that upper-tail cost risk is inversely proportional to the amount of these resources added. Figures 8.14 and 8.15 show the front office transactions (on an average annual basis) and peaking gas capacities, respectively. Portfolios with more of these resource types tend to exhibit higher upper-tail cost risk.

Figure 8.12 – Wind Capacity for Portfolios Ranked by Upper-tail Mean PVRR

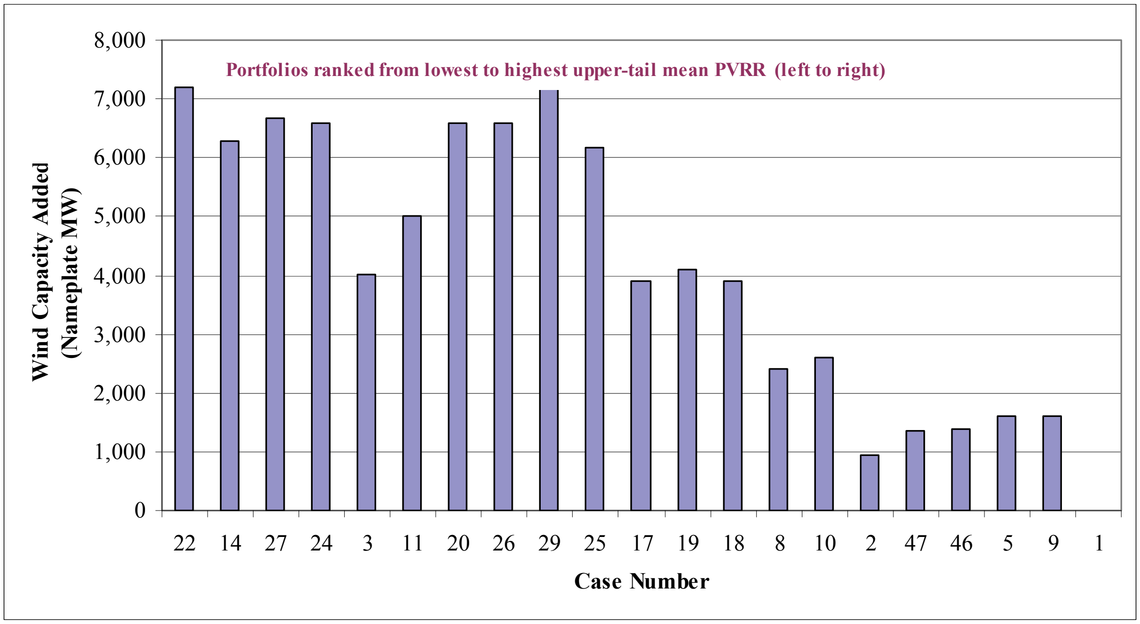


Figure 8.13 – Energy Efficiency Capacity for Portfolios Ranked by Upper-tail Mean PVRR

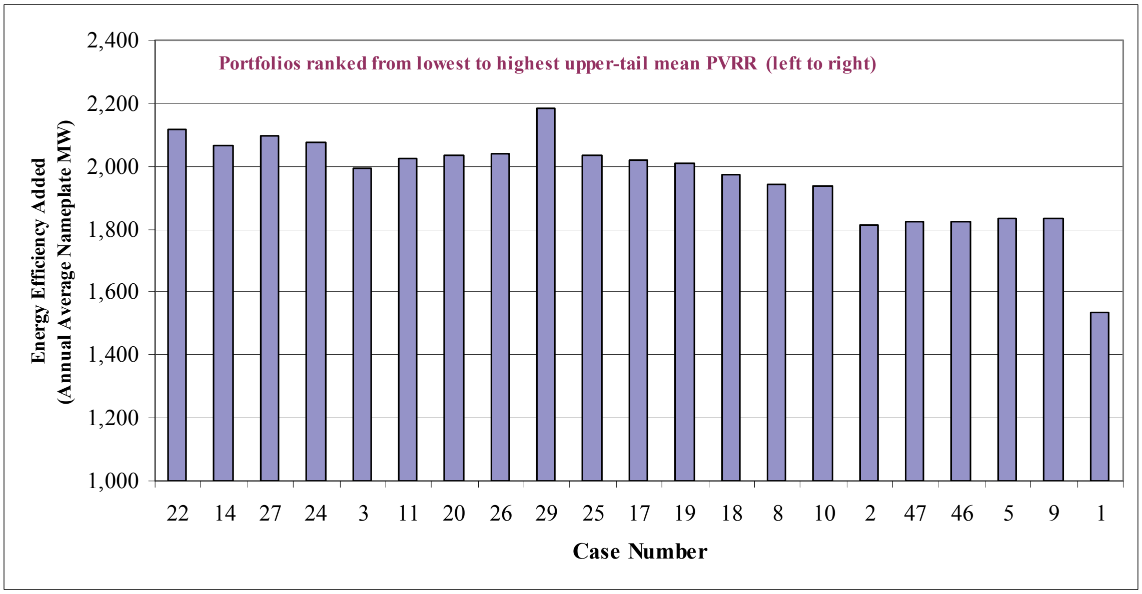


Figure 8.14 – Front Office Transaction Capacity for Portfolios Ranked by Upper-tail Mean PVRR

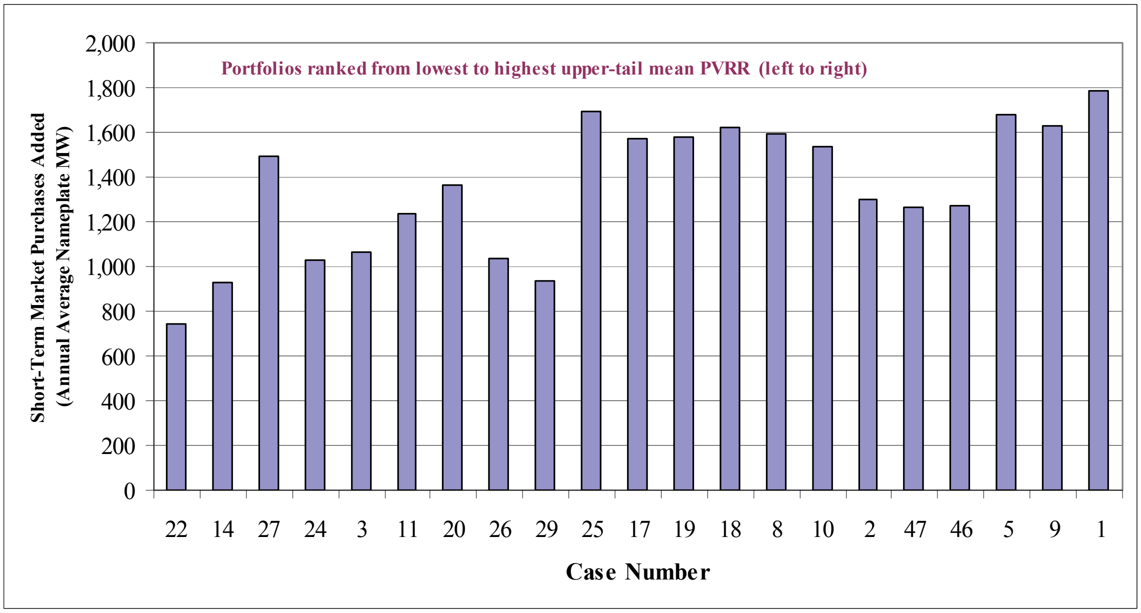
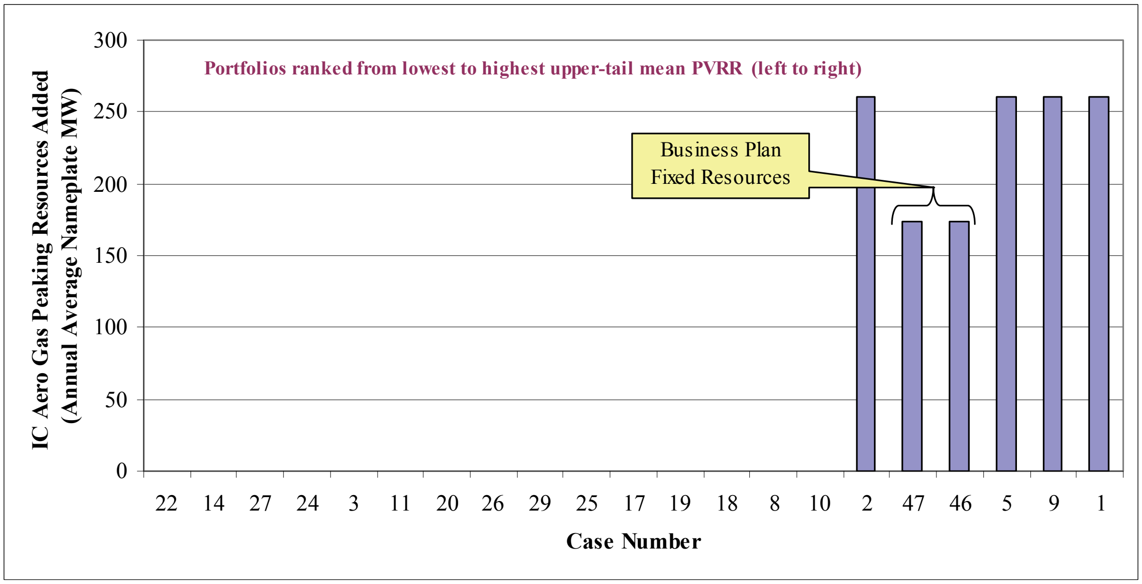


Figure 8.15 – Intercooled Aeroderivative SCCT Capacity for Portfolios Ranked by Upper-tail Mean PVRR



Mean/Upper-Tail Cost Scatter Plots

Figures 8.16 through 8.18 are scatter plots of portfolio cost (mean PVRR) versus high-end cost risk as represented by the upper-tail mean PVRR. These scatter plots show the trade-off between cost and risk at the different CO_2 tax levels.

Across the CO_2 tax levels, there are no portfolios that dominate all others for both mean PVRR and upper-tail mean PVRR. For the $0/ton tax, the case 2 and 3 portfolios dominate all others for mean PVRR and upper-tail mean PVRR, respectively. For the $45/ton tax, the dominant (or nearly dominant) portfolios are represented by cases 8 and 5 for mean PVRR, and cases 22, 14, and 3 for the upper-tail mean. For the $100/ton tax, the dominating portfolios include cases 17 and 25 for mean PVRR, and 27, 22, and 24 for upper-tail mean PVRR.

Figure 8.19 is the scatter plot for the cost and risk measures expressed as averages across the CO_2 tax simulations. Cases 8 and 5 dominate on mean PVRR, while cases 22, 27, and 14 dominate on upper-tail mean PVRR.

Figure 8.16 – Stochastic Cost versus Upper-tail Risk, $0 CO_2 Tax

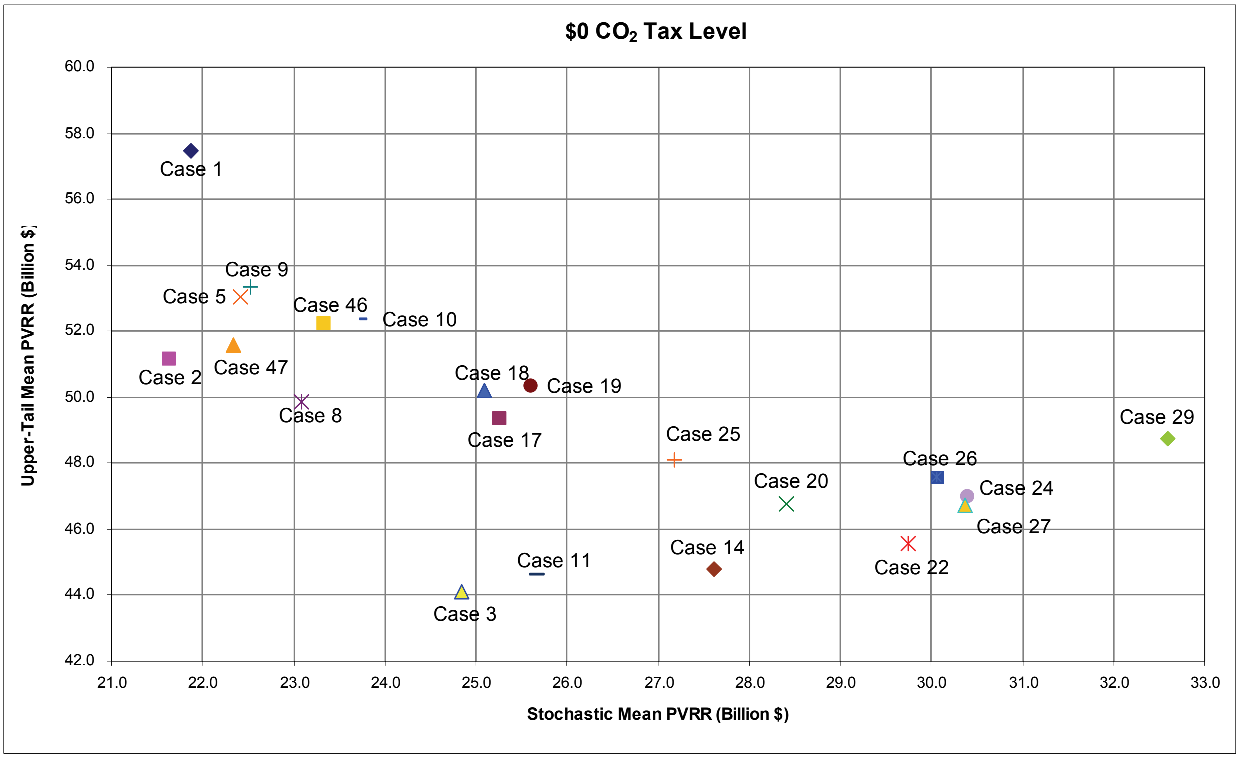


Figure 8.17 – Stochastic Cost versus Upper-tail Risk, $45 CO_2 Tax

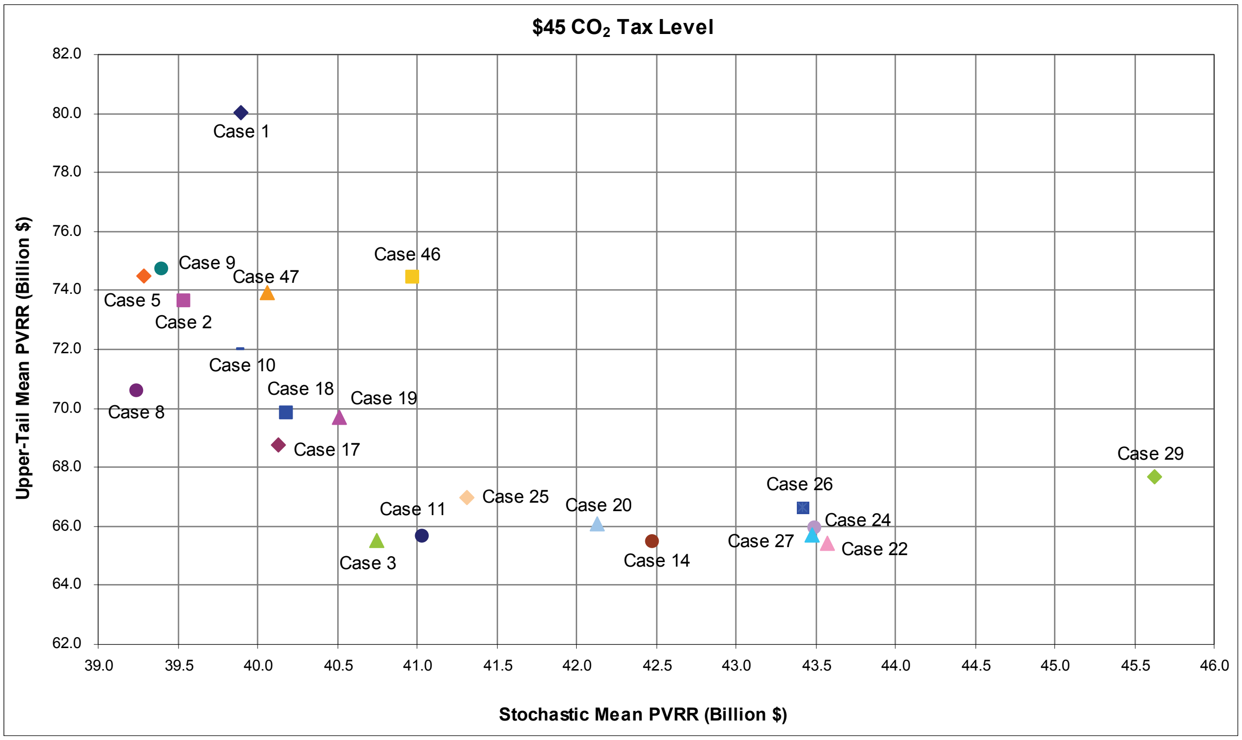


Figure 8.18 – Stochastic Cost versus Upper-tail Risk, $100 CO_2 Tax

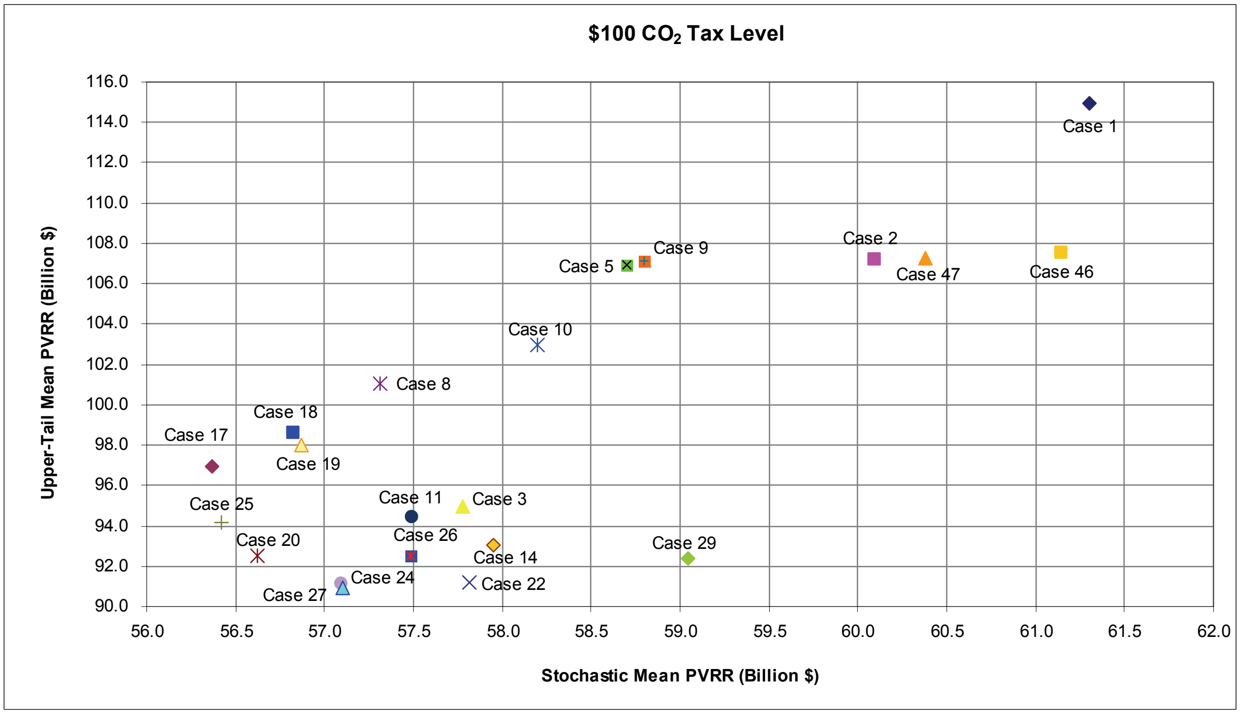
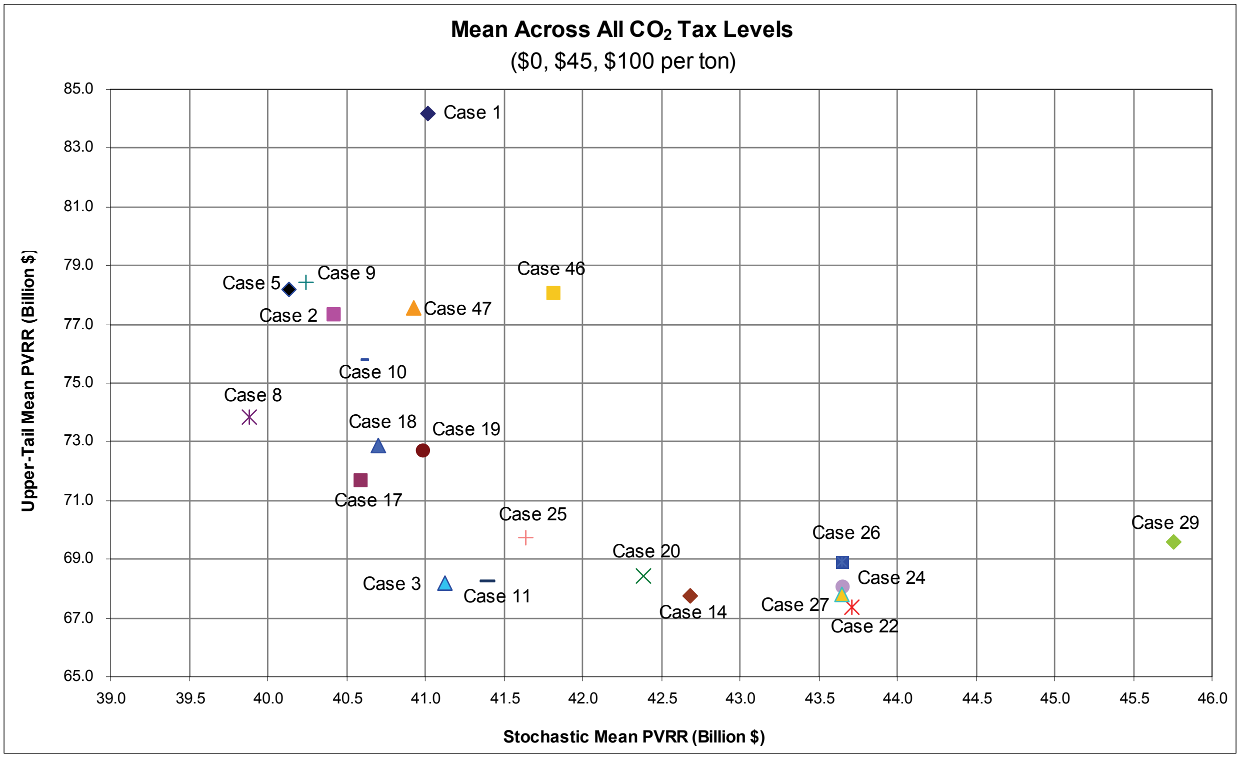


Figure 8.19 – Stochastic Cost versus Upper-tail Risk, Average for CO_2 Tax Levels



Fifth and Ninety-Fifth Percentile PVRR

Table 8.13 reports the 5th and 95th percentile PVRR results for each of the CO_2 tax simulations. Straight averages across the simulations are also shown. The 95th percentile PVRRs are incorporated into the risk-adjusted PVRR results shown above.

Table 8.13 – 5th and 95th Percentile PVRR by Portfolio

Case	CO2 Tax Level, Million Dollars (2009$)						Average 5th Percentile	Average 95th Percentile
	$0/ton		$45/ton		$100/ton			
	5th Percentile	95th Percentile	5th Percentile	95th Percentile	5th Percentile	95th Percentile		
1	12,783	42,378	25,788	64,012	37,447	95,821	25,339	67,404
2	13,242	37,288	26,367	58,989	38,006	89,768	25,872	62,015
3	16,195	35,313	28,995	56,205	39,187	83,429	28,126	58,316
5	13,824	38,965	26,143	59,619	36,667	89,078	25,544	62,554
8	15,227	37,008	25,594	57,877	36,925	86,354	25,916	60,413
9	13,845	39,135	26,254	59,775	36,833	89,222	25,644	62,711
10	15,530	39,069	26,786	58,877	37,377	87,726	26,564	61,890
11	16,042	36,143	29,664	56,410	38,989	83,010	28,232	58,521
14	18,323	36,047	31,913	57,172	39,748	81,853	29,995	58,357
17	17,939	38,113	27,689	57,738	37,331	84,101	27,653	59,984
18	17,497	38,334	27,366	58,161	37,552	85,095	27,472	60,530
19	18,038	38,656	27,945	58,283	37,923	84,818	27,968	60,586
20	19,002	38,039	31,958	56,595	38,589	80,918	29,849	58,518
22	20,516	36,950	32,172	57,320	39,783	81,455	30,823	58,575

Case	CO2 Tax Level, Million Dollars (2009$)						Average 5th Percentile	Average 95th Percentile
	$0/ton		$45/ton		$100/ton			
	5th Percentile	95th Percentile	5th Percentile	95th Percentile	5th Percentile	95th Percentile		
24	21,323	37,971	33,686	57,338	39,783	79,882	31,597	58,397
25	18,385	38,596	29,912	57,527	38,267	82,511	28,855	59,545
26	21,408	38,599	33,688	57,464	40,050	80,862	31,715	58,975
27	21,363	37,689	33,220	57,212	40,064	79,636	31,549	58,179
29	23,269	39,889	34,029	58,893	42,020	81,822	33,106	60,201
46	15,085	38,385	27,953	59,954	39,326	90,703	27,455	63,014
47	14,048	37,753	26,881	59,283	38,290	90,150	26,406	62,395

Production Cost Standard Deviation

The standard deviation of stochastic production costs for each portfolio and the average is shown in table 8.14. (Probability-weighted average values based on alternative expected value CO_2 tax levels are reported in Table 8.27.) This risk measure was assigned a five percent weight for determination of the portfolio preference scores.

As expected, portfolios that rely on coal, wind, and nuclear resources exhibit the lowest levels of production cost variability.

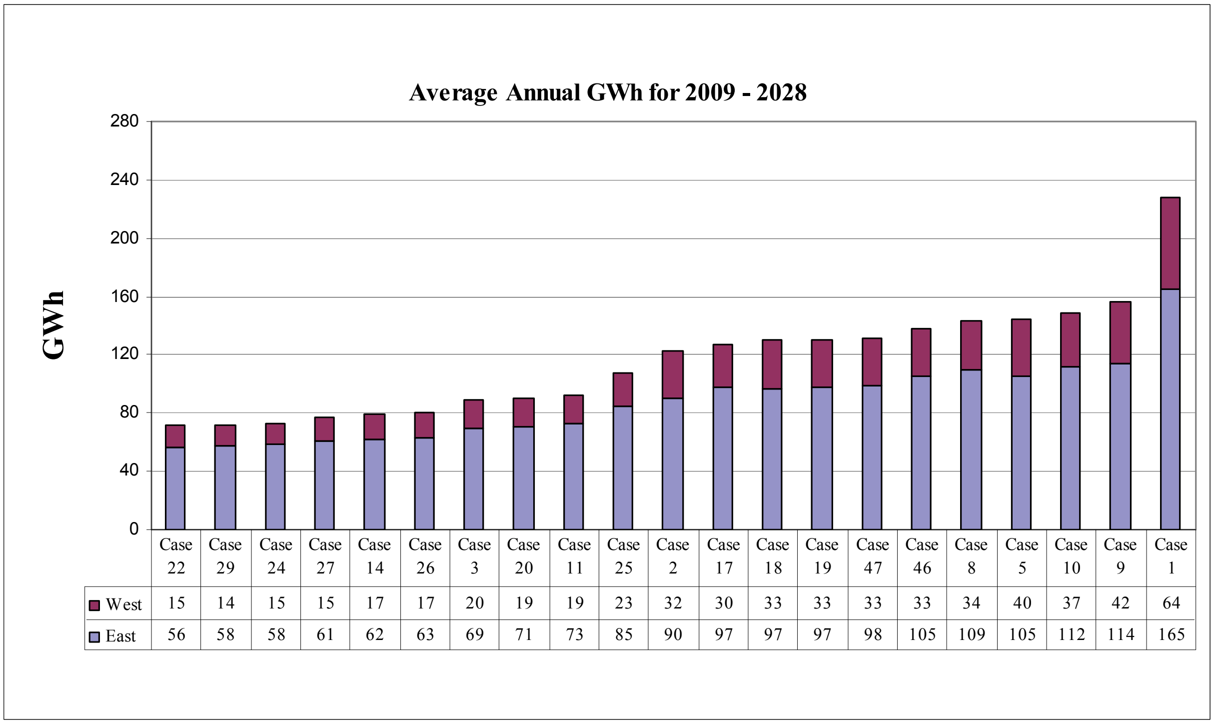
Table 8.14 – Production Cost Standard Deviation

Case	CO2 Tax Level, Million Dollars (2009$)				Rank
	$0/ton	$45/ton	$100/ton	Average	
1	10,486	12,939	18,966	14,130	21
2	8,795	11,312	17,234	12,447	18
3	6,484	8,845	14,129	9,819	9
5	9,067	11,549	17,422	12,679	19
8	8,083	10,534	16,156	11,591	14
9	9,104	11,565	17,412	12,694	20
10	8,552	10,733	16,424	11,903	15
11	6,499	8,778	13,958	9,745	8
14	6,106	8,256	13,205	9,189	6
17	7,438	9,799	15,133	10,790	11
18	7,655	10,033	15,439	11,042	13
19	7,566	9,906	15,238	10,904	12
20	6,336	8,460	13,255	9,350	7
22	5,860	7,854	12,459	8,724	2
24	5,904	7,955	12,530	8,796	4
25	6,808	9,041	14,090	9,980	10
26	6,094	8,201	12,880	9,058	5
27	5,893	7,909	12,434	8,745	3
29	5,920	7,844	12,242	8,669	1
46	8,628	11,142	17,029	12,266	16
47	8,708	11,251	17,188	12,382	17

Energy Not Served (ENS)

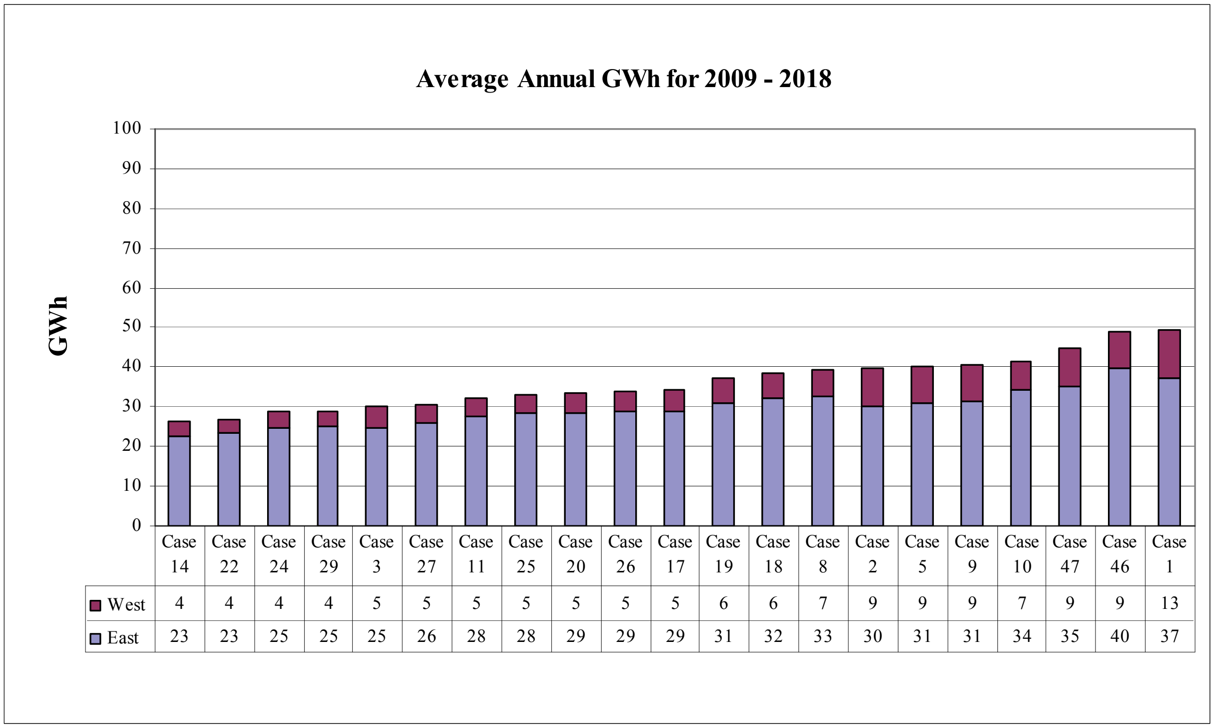
Figures 8.20 and 8.21 below show, respectively, the average annual amount of Energy Not Served (ENS) for the periods 2009-2028 and 2009-2018. Figure 8.22 shows the upper-tail mean ENS by portfolio. As explained in Chapter 7, these are measures of high-end supply reliability risk. Portfolios with low ENS include coal and nuclear, as well as relatively large quantities of wind. Portfolios with relatively high amounts of ENS rely to a greater degree on front office transactions, and in the out-years, growth resources.

Figure 8.20 – Average Annual Energy Not Served, 2009-2028 ($45 CO_2 Tax)



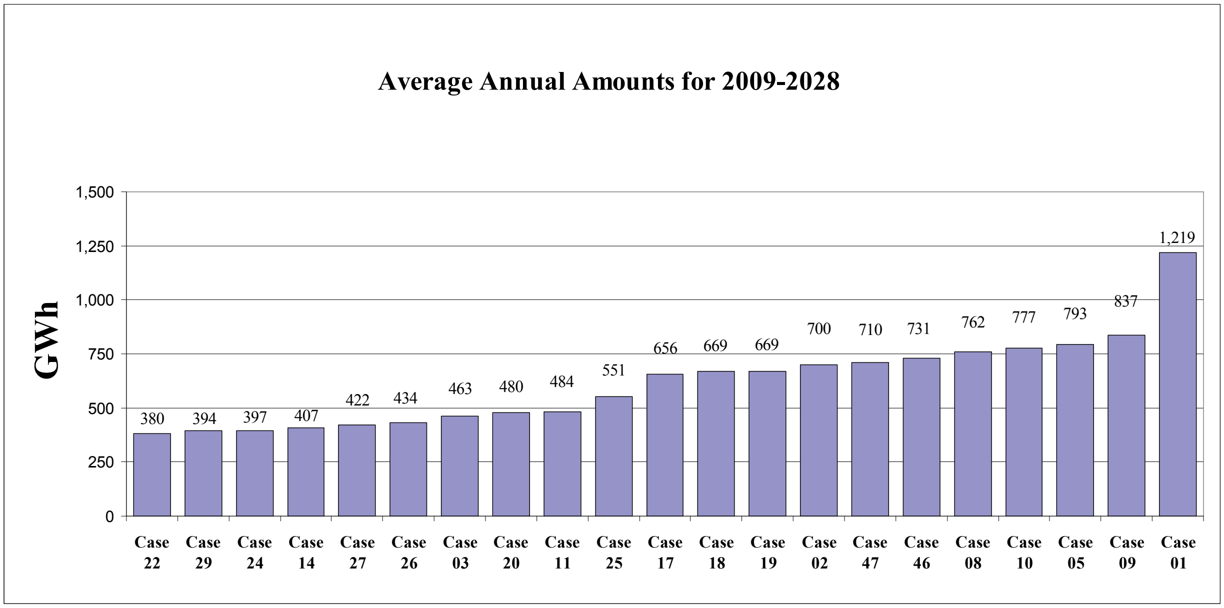
	Case 22	Case 29	Case 24	Case 27	Case 14	Case 26	Case 3	Case 20	Case 11	Case 25	Case 2	Case 17	Case 18	Case 19	Case 47	Case 46	Case 8	Case 5	Case 10	Case 9	Case 1
■ West	15	14	15	15	17	17	20	19	19	23	32	30	33	33	33	33	34	40	37	42	64
□ East	56	58	58	61	62	63	69	71	73	85	90	97	97	97	98	105	109	105	112	114	165

Figure 8.21 – Average Annual Energy Not Served, 2009-2018 ($45 CO_2 Tax)



	Case 14	Case 22	Case 24	Case 29	Case 3	Case 27	Case 11	Case 25	Case 20	Case 26	Case 17	Case 19	Case 18	Case 8	Case 2	Case 5	Case 9	Case 10	Case 47	Case 46	Case 1
■ West	4	4	4	4	5	5	5	5	5	5	5	6	6	7	9	9	9	7	9	9	13
■ East	23	23	25	25	25	26	28	28	29	29	29	31	32	33	30	31	31	34	35	40	37

Figure 8.22 – Upper-tail Energy Not Served, $45 CO_2 Tax



Loss of Load Probability

As discussed in Chapter 7, Loss of Load Probability (LOLP) is represented by the probability of an occurrence of Energy Not Served. Table 8.15 displays the average LOLP for each of the candidate portfolios during the summer peak at various ENS event thresholds, modeled using the \$45 CO_2 tax assumption. The first block of data is the average LOLP for the first ten years of the study period. The second block of data shows the same information calculated for the entire 20 years. The LOLP values in the second block are significantly higher than the first because the variability of the random draws for the stochastic variable draws increases over time, causing greater extremes in the out-years of the study period.

Table 8.16 displays the year-by-year results for the threshold value of 25,000 MWh. For each year, the LOLP value represents the proportion of the 100 simulation iterations where the July ENS was greater than 25,000 MWh. This is the equivalent of 2,500 megawatts for 10 hours. The annual average LOLPs from Table 8.16 constitute one of the supply reliability risk measures used for overall portfolio preference scoring, and is given a five percent weight for this purpose.

Table 8.15 – Average Loss of Load Probability by Event Size During Summer Peak

Average for operating years 2009 through 2018										
Event Size (MWh)	Case Number									
	1	2	3	5	8	9	10	11	14	17
> 0	40%	39%	38%	39%	42%	39%	42%	39%	36%	41%
> 1,000	32%	32%	30%	32%	35%	31%	34%	33%	29%	34%
> 10,000	19%	18%	16%	18%	20%	18%	20%	18%	15%	18%
> 25,000	13%	11%	10%	12%	13%	12%	13%	11%	9%	12%
> 50,000	8%	7%	6%	7%	8%	7%	8%	7%	6%	7%
> 100,000	5%	4%	4%	5%	5%	5%	5%	4%	3%	4%
> 500,000	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2009 through 2028										
Event Size (MWh)	Case Number									
	1	2	3	5	8	9	10	11	14	17
> 0	42%	39%	42%	39%	45%	41%	45%	43%	41%	44%
> 1,000	37%	33%	35%	34%	38%	35%	38%	36%	34%	37%
> 10,000	26%	21%	23%	22%	25%	23%	27%	24%	22%	25%
> 25,000	21%	16%	16%	17%	19%	18%	20%	16%	15%	19%
> 50,000	16%	12%	12%	13%	14%	14%	15%	12%	11%	14%
> 100,000	12%	9%	8%	10%	10%	11%	11%	8%	7%	10%
> 500,000	4%	3%	2%	3%	3%	3%	3%	2%	2%	3%
> 1,000,000	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Average for operating years 2009 through 2018											
Event Size (MWh)	Case Number										
	18	19	20	22	24	25	26	27	29	46	47
> 0	42%	41%	39%	37%	37%	40%	40%	37%	37%	44%	42%
> 1,000	34%	34%	33%	30%	30%	33%	33%	30%	30%	37%	35%
> 10,000	20%	19%	18%	16%	16%	18%	18%	16%	16%	23%	21%
> 25,000	13%	12%	11%	10%	10%	11%	11%	10%	10%	14%	13%
> 50,000	8%	8%	7%	6%	6%	7%	7%	7%	6%	9%	8%
> 100,000	4%	4%	4%	3%	3%	4%	4%	3%	3%	6%	5%
> 500,000	1%	1%	1%	0%	1%	0%	1%	0%	0%	1%	1%

	Average for operating years 2009 through 2018										
Event Size (MWh)	**Case Number**										
	18	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Average for operating years 2009 through 2028										
Event Size (MWh)	**Case Number**										
	18	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
> 0	45%	45%	43%	42%	42%	43%	43%	42%	42%	47%	45%
> 1,000	38%	38%	37%	35%	35%	37%	37%	35%	35%	41%	38%
> 10,000	26%	26%	24%	22%	22%	24%	24%	23%	23%	27%	26%
> 25,000	19%	19%	17%	15%	15%	18%	17%	16%	16%	20%	19%
> 50,000	14%	14%	12%	11%	11%	13%	12%	11%	11%	14%	14%
> 100,000	10%	10%	8%	7%	7%	9%	8%	7%	7%	11%	10%
> 500,000	3%	3%	2%	2%	1%	3%	2%	2%	2%	3%	3%
> 1,000,000	1%	1%	1%	0%	0%	1%	0%	0%	0%	1%	1%

Table 8.16 – Year-by-Year Loss of Load Probability

Probability of ENS Event > 25,000 MWh in July

	Case Number									
Year	**1**	**2**	**3**	**5**	**8**	**9**	**10**	**11**	**14**	**17**
2009	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
2010	14%	12%	10%	12%	12%	12%	12%	11%	9%	11%
2011	9%	9%	8%	9%	9%	9%	9%	9%	8%	9%
2012	7%	7%	5%	7%	7%	7%	7%	7%	5%	7%
2013	17%	14%	10%	14%	12%	17%	16%	13%	10%	12%
2014	18%	17%	8%	17%	17%	19%	17%	10%	8%	16%
2015	17%	15%	10%	15%	15%	15%	15%	10%	10%	10%
2016	11%	11%	13%	11%	15%	11%	15%	13%	11%	13%
2017	8%	6%	12%	6%	14%	6%	14%	11%	11%	14%
2018	23%	19%	19%	20%	23%	20%	23%	19%	17%	21%
2019	21%	12%	16%	15%	18%	15%	18%	15%	15%	17%
2020	22%	15%	19%	19%	23%	19%	23%	19%	19%	22%
2021	24%	17%	22%	19%	20%	21%	24%	22%	22%	23%
2022	26%	12%	15%	17%	16%	17%	22%	16%	15%	21%
2023	30%	25%	25%	25%	30%	28%	30%	25%	24%	30%
2024	30%	23%	21%	22%	23%	25%	27%	23%	21%	24%
2025	39%	27%	27%	36%	39%	36%	35%	30%	27%	36%
2026	30%	25%	25%	27%	29%	26%	29%	26%	25%	29%
2027	26%	21%	22%	25%	27%	25%	27%	23%	22%	23%
2028	35%	25%	25%	26%	29%	29%	31%	20%	23%	28%

	Case Number										
Year	**18**	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
2009	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
2010	12%	12%	11%	9%	9%	11%	11%	11%	10%	12%	12%
2011	9%	9%	9%	8%	8%	9%	9%	8%	8%	9%	9%
2012	7%	7%	7%	5%	5%	7%	7%	5%	5%	7%	7%
2013	17%	14%	12%	10%	10%	13%	13%	10%	10%	12%	12%

	Case Number										
Year	**18**	**19**	**20**	**22**	**24**	**25**	**26**	**27**	**29**	**46**	**47**
2014	18%	18%	13%	8%	8%	13%	13%	10%	9%	17%	17%
2015	15%	10%	10%	10%	10%	10%	10%	10%	10%	15%	15%
2016	13%	13%	13%	13%	13%	13%	13%	13%	13%	16%	15%
2017	14%	14%	13%	11%	11%	12%	13%	12%	12%	21%	14%
2018	21%	21%	21%	17%	20%	20%	21%	21%	19%	26%	23%
2019	17%	17%	16%	15%	15%	15%	16%	16%	15%	21%	18%
2020	22%	22%	21%	19%	21%	21%	21%	21%	21%	24%	23%
2021	23%	23%	23%	22%	23%	23%	23%	23%	23%	25%	23%
2022	20%	21%	17%	15%	16%	19%	17%	18%	17%	20%	18%
2023	30%	30%	28%	25%	25%	28%	29%	30%	27%	31%	29%
2024	25%	24%	24%	21%	21%	22%	22%	24%	21%	24%	24%
2025	36%	36%	29%	23%	24%	33%	24%	24%	23%	34%	33%
2026	29%	31%	27%	25%	24%	29%	24%	24%	24%	29%	28%
2027	23%	22%	21%	21%	20%	22%	20%	20%	20%	25%	24%
2028	29%	28%	23%	22%	22%	28%	22%	18%	20%	27%	26%

LOAD GROWTH IMPACT ON RESOURCE CHOICE

Table 8.17 reports selected stochastic cost and risk results for the cases developed with low and high load growth assumptions. Comparable medium load growth cases are included for reference purposes. The results are also grouped by gas price scenario to highlight the influence of gas and associated electricity prices on portfolio cost as load growth increases.

One observation gleaned from Table 8.17 is that the mix of resource added in response to higher load growth reduces high-end cost risk and Energy Not Served. The System Optimizer model tended to add wind and base-load resources (or CCCT capacity under low gas price scenarios), which reduced upper-tail costs. Much of the cost reduction is seen in the form of net revenue gains from spot market balancing transactions.

Table 8.17 – Stochastic Performance Results for Alternative Load Growth Scenario Cases

Case	Load Growth	Gas Price Scenario / FPC	Mean	5th Percentile	95th Percentile	Upper-Tail Mean	Production Cost Standard Deviation	Ave. Annual ENS (GWh/yr, 2009-2028)
$45/ton CO2 Tax								
4	Low	Low - June 2008	40,270	26,484	63,634	79,735	12,725	345.3
5	Med	Low - June 2008	39,289	26,143	59,619	74,487	9,067	144.6
6	High	Low - June 2008	39,635	27,311	58,044	71,364	10,639	37.7
7	Low	Medium - June 2008	39,877	26,747	59,769	74,618	11,395	255.1
8	Med	Medium - June 2008	39,244	25,594	57,877	70,581	10,534	143.4
12	High	Medium - June 2008	40,027	27,513	56,698	67,054	9,462	38.3
13	Low	High - June 2008	42,040	30,546	57,924	67,240	8,940	117.5
14	Med	High - June 2008	42,481	31,913	57,172	65,453	8,256	79.0

Case	Load Growth	Gas Price Scenario / FPC	Mean	5th Percentile	95th Percentile	Upper-Tail Mean	Production Cost Standard Deviation	Ave. Annual ENS (GWh/yr, 2009-2028)
15	High	High - June 2008	43,893	33,105	56,816	64,247	7,392	26.2
$70/ton CO2 Tax								
16	Low	Medium - June 2008	40,654	27,584	59,033	71,420	10,300	193.3
17	Med	Low - June 2008	42,481	27,689	57,738	68,766	7,438	127.1
21	Low	High - June 2008	43,038	32,516	58,082	67,686	8,677	107.6
22	Med	High - June 2008	43,576	32,172	57,320	65,404	7,854	71.3
$100/ton CO2 Tax								
23	Low	Medium - June 2008	43,624	33,987	57,827	66,798	8,177	88.6
24	Med	Medium - June 2008	43,496	33,686	57,338	65,939	7,955	72.7
28	Low	High - June 2008	43,602	32,764	58,070	67,305	8,376	94.0
29	Med	High - June 2008	45,626	34,029	58,893	67,670	7,844	72.1
33	High	High - June 2008	46,285	27,463	61,638	76,361	11,731	22.2

CAPACITY PLANNING RESERVE MARGIN

PacifiCorp compared stochastic cost and risk measures for portfolios built to meet 12 percent and 15 percent capacity planning reserve margins. This comparative analysis also examined the impact of the resource mix as the cost of CO_2 emission compliance increases, since resources added in response to high CO_2 costs, such as wind and energy efficiency programs, are not subject to fuel price volatility.[49] The relevant comparisons are cases 8 and 41 ($45 CO_2 tax), cases 17 and 42 ($70 CO_2 tax), and cases 24 and 43 ($100 CO_2 tax). Stochastic simulations were only conducted with the $45 CO_2 tax since ENS is not materially affected by differences in emission cost.

For the $45 CO_2 tax cases, increasing the planning reserve margin from 12 percent to 15 percent resulted in additional wind (135 MW) and east-side geothermal (35 MW) resources, as well as increased reliance on front office transactions on both the east and west sides, prior to 2016. The System Optimizer model added an IC aero SCCT in 2016 (261 MW) and subsequently cut back on additional wind resources and front office transactions. Table 8.18 shows the stochastic cost and risk results for the two case portfolios (cases 8 and 41), while Table 8.19 shows the detailed PVRR cost breakdown.

Building to the 15-percent PRM level increased costs and high-end cost risk due to higher fuel and market purchase costs. Partially offsetting these higher operating costs was reduced system balancing costs and lower capital expenditures from the smaller wind investment. (The contribution of the ENS cost as a proportion of total variable costs is less than that reported in the 2007 IRP due to the tiered cost approach applied for this IRP. See the discussion on ENS in Chapter 7 for details.)

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[49] The IRP modeling of wind does not capture the stochastic behavior of wind generation, so related supply reliability risks are not captured in the stochastic analysis.

As expected, with the higher PRM, supply reliability is enhanced as measured by average annual ENS and significant-event LOLP during July. Dividing the incremental portfolio cost by the reduced amount of ENS (487 GWh for 2009-2028) associated with adopting the 15-percent PRM portfolio results in a cost premium of $659/MWh for the ENS reduction.

Table 8.18 – Cost versus Risk for 12% and 15% Planning Reserve Margin Portfolios

				Stochastic Risk, Million $				Supply Reliability	
Planning Reserve Margin (%)	Case	CO_2 Tax	Stochastic Mean PVRR (Million $)	5th Percentile	95th Percentile	Upper Tail (mean of 5 Highest)	Standard Deviation	Annual Ave. ENS (GWh/yr)	Probability of ENS Event > 25 GWh in July (Annual average)
12	8	45	39,244	25,594	57,877	70,581	10,534	143.4	19.1%
15	41	45	39,565	26,113	58,265	71,649	10,715	119.1	15.5%
Difference, 15% less 12%			321	518	388	1,068	181	(24)	-3.7%
12	17	70	40,134	27,689	57,738	68,766	9,799	127.1	18.5%
15	42	70	40,166	27,722	57,591	69,029	9,843	98.6	14.3%
Difference, 15% less 12%			32	33	(147)	263	44	(28)	-4.2%
12	24	100	43,496	33,686	57,338	65,939	7,955	72.7	15.5%
15	43	100	43,486	33,736	57,316	65,874	7,936	69.3	15.1%
Difference, 15% less 12%			(10)	50	(22)	(65)	(19)	(3)	-0.4%

Table 8.19 – PVRR Cost Details ($45/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

	12% PRM	15% PRM	Difference
Cost Component ($ 000)	Case 8	Case 41	(Case 41 less 8)
Variable Cost			
Total Fuel Cost	14,191,867	14,418,506	226,640
Variable O&M Cost	1,222,685	1,241,622	18,937
Total Emission Cost	14,691,301	14,751,942	60,641
Long Term Contracts and Front Office Transactions	8,978,705	9,650,090	671,386
DSM	3,015,434	3,019,019	3,586
Spot Market Balancing			
Sales	(13,089,333)	(13,482,889)	(393,557)
Purchases	3,714,988	3,514,149	(200,839)
Energy Not Served	184,495	152,058	(32,436)
Dump Power	(12,366)	(10,982)	1,384
Reserve Deficiency	73,920	63,886	(10,034)
Total Variable Net Power Costs	**32,971,694**	**33,317,402**	**345,707**
Real Levelized Fixed Costs	**6,272,174**	**6,247,502**	**(24,672)**
Total PVRR	**39,243,869**	**39,564,904**	**321,036**

Table 8.20 – PVRR Cost Details ($70/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

	12% PRM	15% PRM	Difference
Cost Component ($ 000)	**Case 17**	**Case 42**	**(Case 42 less 17)**
Variable Cost			
Total Fuel Cost	13,625,227	13,740,869	115,642
Variable O&M Cost	1,204,222	1,215,560	11,339
Total Emission Cost	13,469,668	13,455,115	(14,553)
Long Term Contracts and Front Office Transactions	8,669,522	9,330,643	661,121
DSM	3,186,054	3,180,545	(5,509)
Spot Market Balancing			
Sales	(13,388,006)	(13,854,964)	(466,958)
Purchases	3,546,102	3,284,808	(261,294)
Energy Not Served	168,279	130,139	(38,141)
Dump Power	(21,406)	(19,997)	1,409
Reserve Deficiency	63,344	52,524	(10,820)
Total Variable Net Power Costs	**30,523,005**	**30,515,242**	**(7,764)**
Real Levelized Fixed Costs	**9,610,984**	**9,651,213**	**40,229**
Total PVRR	**40,133,989**	**40,166,454**	**32,465**

Under a $70 CO_2 tax, increasing the PRM results in a similar build pattern as that for the $45 CO_2 tax cases—including the addition of an IC Aero SCCT in 2016—except that System Optimizer removes less wind and increases front office transactions once the peaking resource is added. As can be seen from Table 8.20, the gap in cost and cost risk narrows between the two portfolios, while supply reliability improves slightly. Table 8.21 shows the PVRR cost detail comparison for the two portfolios. Fuel, net system balancing, and emission costs are reduced due to the extra wind included in the 15-percent PRM portfolio and decreased dispatch of thermal units. The cost premium associated with an ENS reduction of 569 GWh drops to $57/MWh.

For the $100 CO_2 tax cases, increasing the PRM to 15 percent results in a larger amount of DSM (125 MW), particularly Class 1 programs, and distributed standby generation (42 MW), and a slight increase in front office transactions. No peaking gas resources were added in either portfolio. As indicated in Table 8.21, costs and cost risk actually decrease slightly due to this resource mix.[50] The supply reliability benefit is negligible, and there is effectively a positive cost benefit for reducing the 69 GWh of ENS.

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[50] The System Optimizer's deterministic PVRR for case 43 was slightly greater than that for case 24: $60.905 billion versus $60.693 billion. The extrinsic (or real option value) of generation units affected by stochastic variation in fuel and market prices is not accounted in the deterministic capacity optimization solutions.

Table 8.21 – PVRR Cost Details ($100/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

Cost Component ($ 000)	12% PRM Case 24	15% PRM Case 43	Difference (Case 43 less 24)
Variable Cost			
Total Fuel Cost	12,231,023	12,159,435	(71,587)
Variable O&M Cost	1,099,133	1,094,393	(4,741)
Total Emission Cost	12,068,839	12,009,121	(59,718)
Long Term Contracts and Front Office Transactions	7,533,865	8,332,267	798,403
DSM	3,342,009	3,443,037	101,028
Spot Market Balancing			
Sales	(13,956,020)	(14,423,822)	(467,802)
Purchases	3,073,137	2,851,243	(221,894)
Energy Not Served	117,336	112,439	(4,897)
Dump Power	(27,096)	(27,081)	15
Reserve Deficiency	35,439	32,499	(2,940)
Total Variable Net Power Costs	**25,517,664**	**25,583,531**	**65,866**
Real Levelized Fixed Costs	**17,978,326**	**17,902,669**	**(75,657)**
Total PVRR	**43,495,990**	**43,486,200**	**(9,790)**

The main conclusions to be drawn from this analysis are as follows:

- With low to moderately high CO_2 tax assumptions (less than $70/ton), planning to a higher PRM results in a significant cost premium for avoiding unserved energy. Whether this cost premium is worth paying is a subjective determination. However, from a stochastic modeling perspective, it is not cost-effective to invest in incremental generating capacity for reserves given that the cost premium for such investment is above the assumed ENS cost.
- In a high CO_2 cost environment, the incremental resources acquired for the larger capacity reserve requirement shifts to low CO_2-emitting options, which is beneficial from an overall stochastic cost perspective. However, the supply reliability improvement from adding these incremental resources appears to reach a point of diminishing returns between $70/ton and $100/ton.

FUEL SOURCE DIVERSITY

Tables 8.22 through 8.24 show the generation shares by fuel type category for selected years (2013, 2020, and 2028) for new resources in each of the 21 portfolios. The generation mix profile for each portfolio changes over time reflecting the availability of conventional and emerging technologies over the 20-year study period.

All the portfolios increase fuel diversity by reducing the generation share of the Company's coal-fired plants. This result is a consequence of the System Optimizer being allowed to select from a diverse range of resource types in response to various price scenarios that in some scenarios make investment in new conventional thermal generation less cost-effective in the future. In this respect, each portfolio has the optimal fuel mix based on it associated input scenario.

While the portfolios increase overall generation fleet fuel and technology diversity, at the same time, concentration of any one fuel or technology for new resource investment has been found to be suboptimal when considering risk and uncertainty. As an example, portfolios for cases 22 and 24 include relatively large investment in wind resources to mitigate correspondingly large CO_2 compliance costs.

Table 8.22 – Generation Shares for New Resources by Fuel Type for 2013

2013 Generation Shares, New Resources (%)			
Case	**Renewable/DSM**	**Natural Gas**	**Market**
1	25%	16%	59%
2	36%	14%	50%
3	70%	8%	23%
5	36%	14%	50%
8	58%	10%	32%
9	36%	14%	50%
10	49%	11%	40%
11	67%	8%	25%
14	76%	6%	17%
17	68%	8%	24%
18	59%	9%	31%
19	65%	9%	26%
20	68%	7%	25%
22	77%	6%	17%
24	77%	6%	17%
25	68%	7%	25%
26	68%	7%	25%
27	73%	6%	21%
29	77%	7%	16%
46	41%	23%	36%
47	33%	26%	41%
Average	58%	11%	31%

Table 8.23 – Generation Shares for New Resources by Fuel Type for 2020

2020 Generation Shares, New Resources (%)				
Case	**Coal**	**Renewable/DSM**	**Natural Gas**	**Market**
1	0%	34%	17%	49%
2	16%	41%	14%	29%
3	11%	75%	3%	11%
5	0%	57%	11%	33%
8	0%	67%	5%	27%
9	0%	58%	10%	32%
10	0%	69%	4%	26%
11	7%	79%	3%	11%
14	7%	81%	3%	10%
17	0%	76%	4%	21%
18	0%	75%	4%	21%
19	0%	76%	3%	20%
20	0%	83%	3%	15%
22	6%	84%	2%	8%

2020 Generation Shares, New Resources (%)				
Case	**Coal**	**Renewable/DSM**	**Natural Gas**	**Market**
24	0%	83%	**3%**	14%
25	0%	81%	3%	16%
26	0%	82%	3%	15%
27	0%	83%	3%	14%
29	0%	86%	3%	12%
46	14%	50%	11%	25%
47	14%	50%	11%	25%
Average	4%	70%	6%	20%

Table 8.24 – Generation Shares for New Resources by Fuel Type for 2028

2028 Generation Shares, New Resources (%)					
Case	**Coal**	**Nuclear**	**Renewable/DSM**	**Natural Gas**	**Market**
1	0%	0%	34%	11%	55%
2	10%	0%	47%	8%	35%
3	9%	0%	68%	3%	20%
5	5%	0%	50%	7%	38%
8	0%	0%	61%	4%	35%
9	5%	0%	50%	7%	38%
10	0%	0%	63%	3%	34%
11	6%	0%	71%	2%	21%
14	9%	0%	76%	2%	13%
17	9%	0%	61%	2%	28%
18	9%	0%	61%	2%	28%
19	8%	0%	62%	2%	28%
20	6%	11%	62%	2%	19%
22	11%	12%	70%	2%	6%
24	6%	23%	64%	2%	6%
25	7%	0%	69%	2%	22%
26	6%	23%	66%	2%	3%
27	5%	20%	56%	2%	17%
29	9%	21%	66%	2%	2%
46	9%	0%	51%	7%	33%
47	9%	0%	51%	7%	33%
Average	7%	6%	60%	4%	23%

GENERATOR EMISSIONS FOOTPRINT

Carbon Dioxide

The portfolio cumulative generator CO_2 emissions for the simulation period are presented in Table 8.25 by CO_2 tax level and the average across tax levels. Figure 8.23 shows the emissions footprint in bar chart form by tax level, with portfolios ranked from lowest to highest emissions (left to right) for the \$45 tax.

The portfolios with the lowest cumulative CO_2 emissions are those optimized in response to both the \$100 CO_2 tax and high gas price scenarios. At the other extreme, portfolios optimized with no CO_2 tax have the highest emissions. A notable exception is the portfolio for case 3. This portfolio was optimized with the high June 2008 gas price scenario, and as a consequence, includes both a pulverized coal plant in 2018 and about 3,900 MW of wind by 2028. This resource combination lowered the CO_2 emissions to less than the amount produced by a number of portfolios optimized with the \$45 CO_2 tax; specifically, those for cases 5, 8, 9, and 10.

Table 8.25 – Cumulative Generator Carbon Dioxide Emissions, 2009-2028

	Cumulative Generator CO2 Emissions, 2009-2028 (1,000 Short Tons)			
	CO2 Tax Level			
Case	**\$0**	**\$45**	**\$100**	**Average**
1	1,073,510	899,802	835,943	936,418
2	1,089,942	892,740	821,440	934,707
3	1,028,918	807,954	730,560	855,811
5	1,036,052	841,758	772,358	883,389
8	1,020,539	818,050	746,063	861,551
9	1,037,463	843,569	774,282	885,105
10	1,025,000	823,005	751,041	866,349
11	1,014,089	794,324	716,885	841,766
14	997,347	768,352	688,991	818,230
17	969,127	759,332	687,261	805,240
18	977,559	769,036	696,885	814,493
19	973,843	764,943	692,880	810,555
20	928,315	715,884	643,360	762,520
22	944,887	722,610	647,183	771,560
24	897,912	686,454	615,226	733,197
25	948,159	733,850	660,573	780,861
26	909,892	699,942	628,852	746,228
27	895,656	686,694	616,273	732,874
29	899,919	686,052	615,523	733,831
46	1,080,785	882,033	810,307	924,375
47	1,081,815	883,284	811,541	925,547

Figure 8.23 – Generator Carbon Dioxide Emissions by CO_2 Tax Level

Other Pollutants

Table 8.26 reports for each case portfolio the emissions footprint for sulfur dioxide (SO_2), nitrous oxides (NO_X), and mercury (Hg). On an average basis across each CO_2 tax level, the portfolio for case 24 has the lowest emissions of SO_2. For NO_X, the lowest-emitting portfolio was for case 27, while for mercury, the lowest-emitting portfolio was case 14.

Table 8.26 – Generator Carbon Dioxide Emissions by CO_2 Tax Level

Case	Emission Types and Units			Emission Types and Units			Emission Types and Units		
	SO2	NOx	Hg	SO2	NOx	Hg	SO2	NOx	Hg
	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds
	$0 CO2 Tax			$45 CO2 Tax			$100 CO2 Tax		
1	917	1,214	14,190	735	979	11,665	670	905	10,652
2	922	1,207	14,149	717	947	11,330	647	865	10,244
3	877	1,148	13,648	653	865	10,531	580	776	9,440
5	900	1,191	14,266	698	933	11,591	629	851	10,535
8	883	1,171	13,719	676	908	10,831	606	825	9,752
9	900	1,192	14,281	699	934	11,616	630	853	10,564
10	886	1,175	13,766	679	912	10,898	609	829	9,821
11	869	1,142	13,473	649	863	10,400	577	775	9,322
14	856	1,124	13,329	630	836	10,168	558	746	9,089
17	852	1,143	13,971	642	865	11,356	574	779	10,382
18	859	1,151	14,086	649	874	11,476	580	789	10,495
19	855	1,147	14,037	646	870	11,430	577	784	10,458
20	822	1,102	13,423	610	824	10,831	543	738	9,893
22	825	1,095	13,426	605	807	10,724	537	720	9,780

Case	Emission Types and Units			Emission Types and Units			Emission Types and Units		
	SO2	NOx	Hg	SO2	NOx	Hg	SO2	NOx	Hg
	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds	1000 Tons	1000 Tons	Pounds
	$0 CO2 Tax			$45 CO2 Tax			$100 CO2 Tax		
24	796	1,069	13,049	586	793	10,437	521	709	9,526
25	835	1,123	13,720	621	841	11,070	552	754	10,100
26	805	1,081	13,181	597	806	10,605	532	722	9,697
27	795	1,067	12,954	588	793	10,403	523	710	9,507
29	799	1,072	13,092	590	792	10,462	526	710	9,562
46	917	1,202	14,091	710	941	11,241	639	857	10,153
47	918	1,203	14,103	712	942	11,264	641	858	10,177

TOP-PERFORMING PORTFOLIO SELECTION

Chapter 7 outlined the portfolio preference scoring approach for selecting the top portfolios. Preference-scoring grids were prepared for 12 expected value CO_2 tax levels, ranging from $15 to $70 at $5 increments. Table 8.27 shows the expected value CO_2 tax levels and associated probabilities. Stochastic cost results for the three CO_2 tax production cost simulations were weighted with these probabilities. These probability-weighted results are reported in Appendix B, and include risk-adjusted PVRR, customer rate impact, CO_2 cost exposure, upper-tail mean PVRR, and standard deviation of production costs. The 12 preference-scoring grids are also reported in Appendix B. A preference-scoring grid sample—for the $45 expected value CO_2 tax—is shown as Table 8.28.

Table 8.27 – Probability Weights for Calculating Expected Value CO_2 Tax Levels

Expected Value CO2 Tax	Probability (%)		
	$0/ton	$45/ton	$100/ton
$15	66	34	0
$20	55	45	0
$25	45	55	0
$30	40	55	5
$35	35	55	10
$40	30	55	15
$45	25	55	20
$50	20	55	25
$55	15	55	30
$60	10	55	35
$65	5	55	40
$70	0	55	45

Table 8.28 – Measure Rankings and Preference Scores, $45/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	2.7	2.0	1.0	2.7	10.0	10.0	10	**3.6**	**3.2**
2	1.6	2.1	1.3	1.6	7.2	3.9	2.1	**2.1**	**1.2**
3	2.8	3.2	6.7	2.8	2.8	2.0	2.1	**3.0**	**2.4**
5	1.3	1.1	1.6	1.3	7.6	5.2	4.6	**2.0**	**1.0**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**2.0**	**1.1**
9	1.5	1.0	1.8	1.5	7.6	5.9	5.8	**2.2**	**1.3**
10	2.1	2.1	3.8	2.1	6.2	5.5	8.9	**2.9**	**2.2**
11	3.3	1.4	7.1	3.3	2.7	2.2	2.9	**3.0**	**2.4**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.9**	**4.9**
17	2.2	1.5	6.6	2.2	4.5	4.2	6.6	**2.7**	**2.0**
18	2.3	2.5	5.4	2.3	4.9	4.4	7.8	**3.0**	**2.4**
19	2.8	2.6	6.4	2.8	4.7	4.4	7.1	**3.3**	**2.8**
20	4.9	3.4	8.0	4.9	2.1	2.1	4.3	**4.4**	**4.3**
22	6.9	6.7	10.0	6.9	1.1	1.0	1.0	**6.1**	**6.6**
24	6.8	7.8	9.6	6.8	1.2	1.1	1.5	**6.3**	**6.9**
25	3.8	3.3	8.0	3.8	3.1	3.1	5.1	**3.9**	**3.6**
26	6.8	7.4	9.6	6.8	1.6	1.5	3.4	**6.4**	**6.9**
27	6.8	6.2	9.6	6.8	1.1	1.3	2.6	**6.1**	**6.5**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.7	3.2	2.7	3.7	6.9	4.8	9.0	**4.1**	**3.8**
47	2.4	2.4	1.5	2.4	7.1	4.5	6.9	**2.9**	**2.3**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

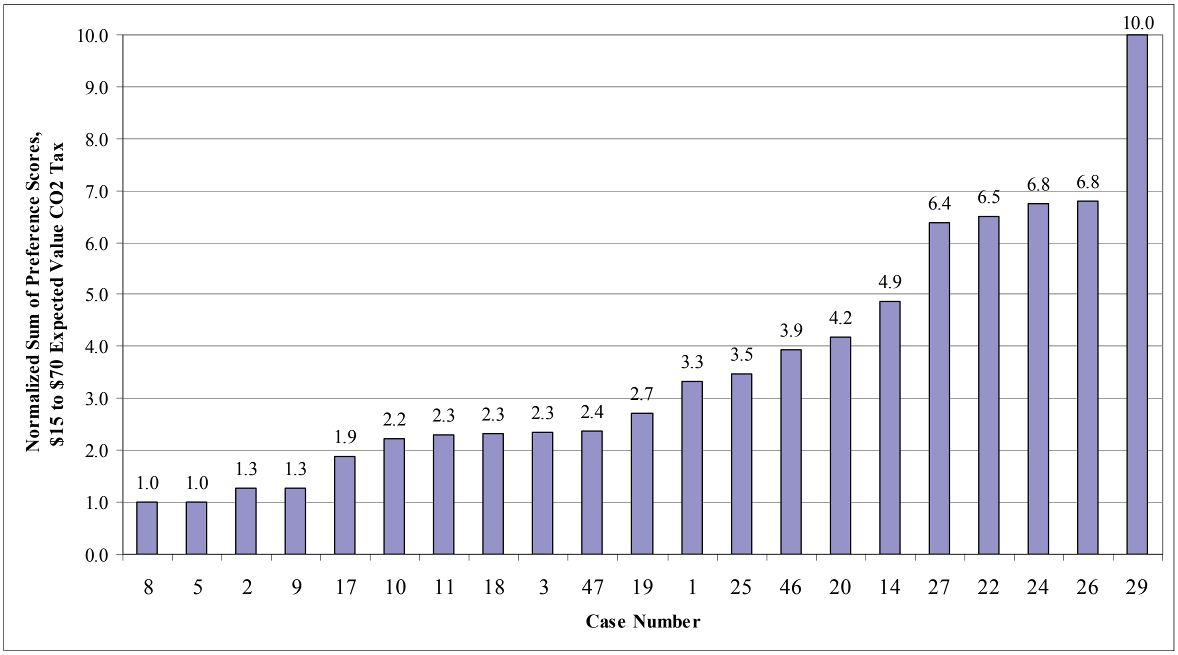
Table 8.29 reports the portfolio preference scores for each of the 12 expected value CO_2 tax levels. When summing the normalized preference scores across the expected value CO_2 tax levels, the portfolios for cases 5 and 8 have the best scores, followed by cases 9 and 2. (These portfolios are shown highlighted in the table.) These four portfolios were therefore selected as the candidates for preferred portfolio selection.

Table 8.29 – Portfolio Preference Scores

	Expected Value CO2 Tax												
Case	**$15**	**$20**	**$25**	**$30**	**$35**	**$40**	**$45**	**$50**	**$55**	**$60**	**$65**	**$70**	**Rank Sum**	**Normalized Score**
1	2.40	2.43	2.47	2.56	2.67	2.82	3.15	3.61	4.19	4.88	5.71	6.81	43.7	3.33
2	1.00	1.00	1.00	1.00	1.00	1.00	1.19	1.50	1.93	2.43	3.03	3.96	20.0	1.26
3	3.14	3.07	3.00	2.86	2.69	2.49	2.41	2.39	2.44	2.49	2.56	2.90	32.4	2.35
5	1.63	1.53	1.43	1.31	1.17	1.01	1.00	1.09	1.27	1.49	1.76	2.37	17.0	1.00
8	2.21	2.06	1.92	1.72	1.48	1.21	1.07	1.00	1.00	1.00	1.02	1.35	17.0	1.00
9	1.83	1.74	1.64	1.53	1.40	1.25	1.25	1.35	1.54	1.77	2.06	2.67	20.0	1.26
10	2.98	2.86	2.75	2.61	2.45	2.28	2.23	2.26	2.36	2.47	2.63	3.07	30.9	2.22
11	3.51	3.39	3.27	3.07	2.85	2.56	2.38	2.25	2.17	2.09	2.01	2.20	31.8	2.29
14	5.46	5.42	5.38	5.27	5.15	4.99	4.91	4.88	4.88	4.88	4.89	5.08	61.2	4.86
17	3.69	3.49	3.29	3.01	2.68	2.30	2.01	1.75	1.53	1.28	1.00	1.00	27.0	1.87
18	3.81	3.64	3.46	3.23	2.96	2.64	2.43	2.25	2.12	1.96	1.80	1.90	32.2	2.33
19	4.18	4.02	3.85	3.62	3.35	3.04	2.82	2.64	2.49	2.33	2.15	2.22	36.7	2.72
20	5.93	5.75	5.56	5.30	5.00	4.64	4.32	4.02	3.71	3.37	2.99	2.81	53.4	4.18
22	7.24	7.18	7.11	7.00	6.87	6.70	6.58	6.47	6.37	6.26	6.14	6.13	80.1	6.51
24	7.91	7.79	7.67	7.51	7.31	7.08	6.87	6.65	6.43	6.17	5.87	5.67	82.9	6.76
25	5.15	4.97	4.79	4.54	4.24	3.89	3.60	3.33	3.08	2.79	2.47	2.37	45.2	3.46
26	7.80	7.69	7.58	7.43	7.26	7.06	6.89	6.72	6.55	6.35	6.12	6.00	83.5	6.81
27	7.72	7.58	7.44	7.25	7.02	6.75	6.50	6.24	5.97	5.67	5.32	5.10	78.6	6.38
29	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	120.0	10.00
46	3.01	3.07	3.14	3.24	3.35	3.49	3.80	4.22	4.75	5.38	6.13	7.13	50.7	3.94
47	1.91	1.93	1.95	1.97	2.01	2.05	2.27	2.60	3.06	3.58	4.22	5.15	32.7	2.37

Figure 8.24 shows the portfolio preference scores from Table 8.36 sorted from best to worst.

Figure 8.24 – Portfolio Preference Scores, sorted from Best to Worst



Sensitivity of Portfolio Preference Rankings to Measure Importance Weights

To test the sensitivity of the preference scores to changes in measure importance weights—particularly for the top-performing portfolios—PacifiCorp constructed a preference-scoring grid for the expected value \$45 CO_2 tax level with an alternate set of weights. The alternate weights reflect a combination of comments and recommendations made by participants at PacifiCorp's February 2, 2009 public meeting, and place more importance on risk-adjusted PVRR and CO_2 cost risk, but none on capital costs. These alternative weights are shown in Table 8.30.

Table 8.30 – Alternate Measure Importance Weights

Measures	Weight
Cost	
Risk-adjusted PVRR	50%
Customer Rate Impact	10%
Capital Cost for 2009-2018	0%
Risk	
CO_2 Cost Exposure	25%
Production Cost Standard Deviation	5%
Average annual ENS	5%
Average Annual Probability of ENS events for July exceeding 25 GWh	5%

The resulting measure rankings and preference scores based on these alternate weightings are reported in Table 8.31. The alternate weights result in changes to scores of no more than two-tenths of a point. The score for case 8 registers a slight improvement relative to the score for case 5, resulting in a switch in ranking. However, portfolios 8, 5, 2, and 9 remain the top ranked under both weighting schemes. Based on this result, PacifiCorp concludes that the top-performing portfolios are robust choices given variations in the measure weighting schemes.

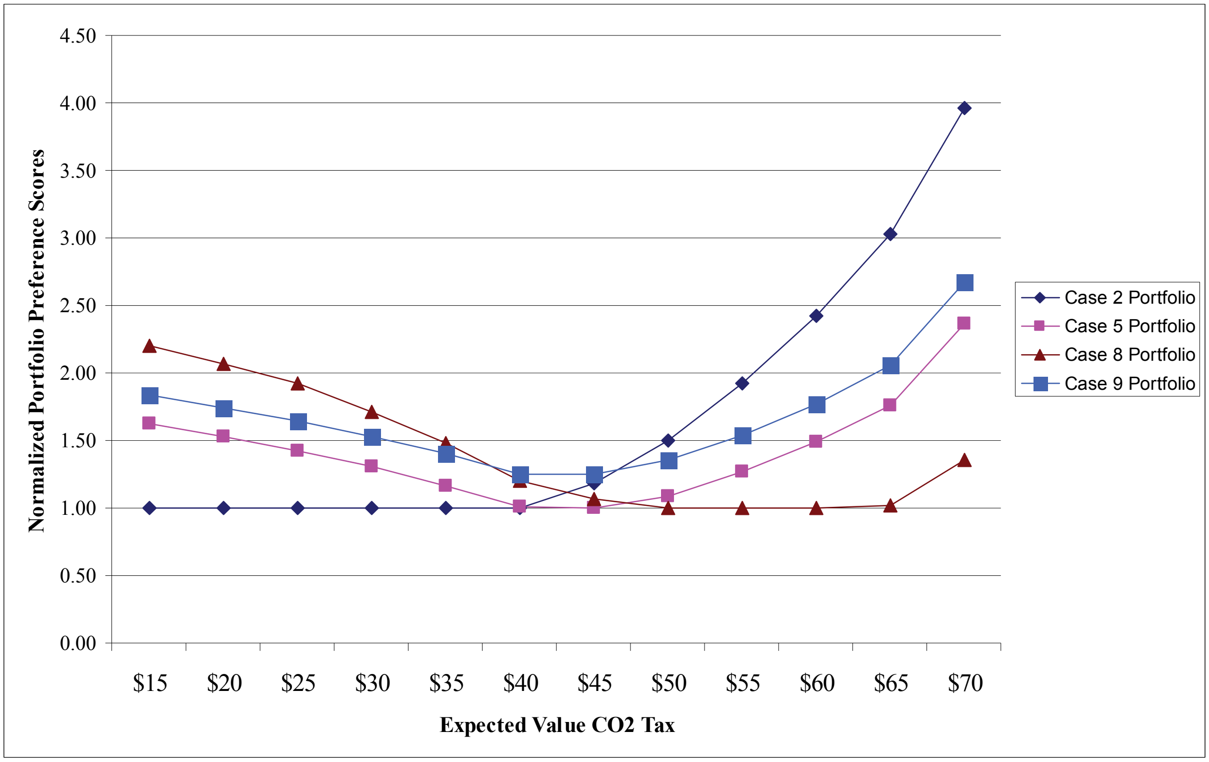
Table 8.31 – Measure Rankings and Preference Scores with Alternative Measure Importance Weights, $45/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1	2.7	2.0	1.0	2.7	10.0	10.0	10	**3.7**	**3.5**
2	1.6	2.1	1.3	1.6	7.2	3.9	2.1	**2.1**	**1.3**
3	2.8	3.2	6.7	2.8	2.8	2.0	2.1	**2.8**	**2.3**
5	1.3	1.1	1.6	1.3	7.6	5.2	4.6	**2.0**	**1.2**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**1.8**	**1.0**
9	1.5	1.0	1.8	1.5	7.6	5.9	5.8	**2.2**	**1.5**
10	2.1	2.1	3.8	2.1	6.2	5.5	8.9	**2.8**	**2.3**
11	3.3	1.4	7.1	3.3	2.7	2.2	2.9	**3.0**	**2.5**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.7**	**4.8**
17	2.2	1.5	6.6	2.2	4.5	4.2	6.6	**2.6**	**2.0**
18	2.3	2.5	5.4	2.3	4.9	4.4	7.8	**2.9**	**2.4**
19	2.8	2.6	6.4	2.8	4.7	4.4	7.1	**3.2**	**2.8**
20	4.9	3.4	8.0	4.9	2.1	2.1	4.3	**4.4**	**4.4**
22	6.9	6.7	10.0	6.9	1.1	1.0	1.0	**6.0**	**6.5**
24	6.8	7.8	9.6	6.8	1.2	1.1	1.5	**6.1**	**6.6**
25	3.8	3.3	8.0	3.8	3.1	3.1	5.1	**3.8**	**3.5**
26	6.8	7.4	9.6	6.8	1.6	1.5	3.4	**6.2**	**6.7**
27	6.8	6.2	9.6	6.8	1.1	1.3	2.6	**6.0**	**6.4**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.7	3.2	2.7	3.7	6.9	4.8	9.0	**4.2**	**4.1**
47	2.4	2.4	1.5	2.4	7.1	4.5	6.9	**3.0**	**2.5**

Importance Weights	**50%**	**10%**	**0%**	**25%**	**5%**	**5%**	**5%**

As indicated above, the portfolios developed under cases 2, 5, 8, and 9 performed the best according to the final preference scores. For selecting the preferred portfolio, of interest is how the preference scores for these portfolios vary across the CO_2 tax levels. Figure 8.25 shows the scores at each expected value CO_2 tax level. The case 2 portfolio scores the best with tax levels below $40, while the case 8 portfolio scores the best with tax levels at $50 and above. Case 5 appears to represent the “least-regrets” portfolio with respect to the range of preference scores, avoiding the highest scores like the case 2 and 8 portfolios, and always dominating the case 9 portfolio.

Figure 8.25 – Preference Scores by Expected Value CO_2 Tax, Top-performing Portfolios



Based on the preference scores and the analysis above, PacifiCorp dropped cases 2 and 9 from further consideration as the preferred portfolio. A discussion of the comparative advantages, disadvantages, and risks for the two remaining portfolios is provided below.

Case 5 versus Case 8 Portfolio Assessment

Both case 5 and case 8 are equally strong contenders to be the 2008 IRP preferred portfolio. The main difference between the two portfolios is that case 8 includes 1,150 MW more wind in the first 10 years (600 MW more overall), and lacks a gas peaking resource in 2016. Case 5 also includes more east-side front office transactions in the first 10 years than case 8.

The assumed CO_2 cost is the key determinant for overall portfolio performance: case 8 out-performs case 5 with CO_2 taxes at $45 and above, but the reverse is true with CO_2 taxes below $45. Noteworthy is that case 5 out-performs case 8 on customer rate impact for all CO_2 tax levels.

In terms of relative advantages independent of the operational cost impact of a CO_2 price, case 5 has a smaller capital cost (by $2.2 billion), as well as a lower probability of a major ENS event during the system peak month. In contrast, case 8 has a lower upper-tail cost and upper-tail ENS, reflecting the variable operating cost savings benefits of the additional wind and its selected location in load areas that exhibit relatively higher ENS.

A disadvantage for case 8 is the amount of wind investment in the first 10 years, which reaches 2,600 MW. The average annual capacity added for 2012 through 2018 exceeds 300 MW, which is a concern from procurement, rate impact, construction project management, and operational perspectives. This wind is not needed for RPS compliance purposes, and its economic desirability hinges on continuation of a production tax credit (or comparable financial incentive), a significant CO_2 cost penalty benefiting clean energy alternatives, and a robust market for sales of excess energy, particularly during off-peak hours. On the other hand, the incremental wind provides added price hedge benefits due to the lack of fuel costs and exposure to future CO_2 compliance costs. The respective wind expansion patterns for cases 5 and 8 suggest that the optimal wind strategy is to identify a wind capacity floor and upper value that are updated as aspects of future federal CO_2 compliance cost and renewable energy policies becomes clearer. This strategy takes advantage of the relatively short development lead-time and modular construction of wind resources. PacifiCorp's action plan discusses this wind strategy in more detail.

Both portfolios have heavier reliance on market purchases relative to most other portfolios, which increases the risk of a high-end cost outcome. Case 8 does better than case 5, due to more renewable resources and east-side Class 2 DSM, but both appear in the bottom quartile of ranking results for upper-tail risk measures. This higher tail risk must be evaluated in the context of the timing of when the tail risk is most pronounced, and other risks that these portfolios help mitigate. For example, Table 8.32 compares the 95th percentile PVRRs for the case 5, 8 and 22 portfolios given a 10-year span (2009-2018) and 20-year span (2009-2028). The case 22 portfolio ranks at the top for upper-tail mean PVRR.

Table 8.32 – Short- and Long-term 95th Percentile PVRR Comparisons

Case	95th Percentile, Million $ $45/ton CO2 Tax 10-Year 2009-2018	95th Percentile, Million $ $45/ton CO2 Tax 20-Year 2009-2028
5	24,832	59,619
8	23,952	57,877
22	24,453	57,320
Case 5 less 22	379	2,299
Case 8 less 22	(501)	558

As the comparison shows, differences in upper-tail mean PVRR are significantly lower under the 10-year view. Case 8 actually performs better than case 22, owing primarily to the high capital costs associated with a pulverized coal plant and 4,500 MW of wind included in case 22. The portfolios that do well on the 20-year upper-tail cost measures rely on large amounts of wind resources, as well as base-load resources such as conventional pulverized coal and nuclear in the out-years—resources with their own significant risks. This comparison again illustrates the tradeoff between expected costs and high-end cost risk.

As emphasized in PacifiCorp's 2007 IRP, PacifiCorp believes that firm market purchases benefit the preferred portfolio by increasing planning flexibility and resource diversity at a time of considerable regulatory uncertainty. The current economic recession, coupled with the Company's need for grid infrastructure and clean air investments, magnifies the importance of such flexibility for maintaining affordable customer rates. Nevertheless, PacifiCorp recognizes the risks associated with market reliance, and has in place a price hedging strategy to mitigate these risks. A description of PacifiCorp's price hedging strategy is provided in Chapter 9.

Regarding fuel source diversity, the case 8 portfolio has a greater proportion of renewable generation—and generation reduction in the case of Class 2 DSM—than for case 5, particularly in the near term. On the other hand, case 5 has a greater share of gas generation, and for the first 10 years, more reliance on generation from market purchases. By 2028, the generation mix for the two portfolios look similar. The significant difference is that case 5 includes a clean coal resource in 2025, while case 8 depends on much earlier wind investment to meet CO_2 and RPS compliance requirements.

Scenario Risk Assessment

Risk Scenario Development

In accordance with the Public Service Commission of Utah's acknowledgement order for PacifiCorp's last IRP, the Company followed the Commission's instruction to "examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions".[51] PacifiCorp selected the three top-performing portfolios—cases 5, 8, and 9—for this analysis (Case 2 had a. were fixed in the System Optimizer capacity expansion model. The model was then executed to solve for the deterministic PVRR under each selected input scenario. The input scenarios consisted of the following case assumptions:

- Medium load growth forecast
- June 2008 forward price curves and high/low variations
- Varying CO_2 tax levels: \$0, \$45, \$70, and \$100

The resulting ten risk scenarios, along with the represented cases, are listed in Table 8.33. A total of 30 deterministic PVRRs therefore represent the outcome of the scenario risk modeling.

Table 8.33 – Scenario Risk Case Definitions

Risk Scenario Number	Case Number	CO_2 tax (\$/ton)	Gas Price Forecast	Load Growth Scenario
1	1	\$0	Low	Medium
2	2	\$0	Medium	Medium
3	3	\$0	High	Medium
4	5	\$45	Low	Medium
5	8	\$45	Medium	Medium
6	14	\$45	High	Medium
7	17	\$70	Medium	Medium
8	22	\$70	High	Medium
9	24	\$100	Medium	Medium

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[51] Public Service Commission of Utah, Report and Order, In the Matter of the PacifiCorp 2006 Integrated Resource Plan, Docket No. 07-2035-01, February 6, 2008, p. 40.

Risk Scenario Number	Case Number	CO_2 tax ($/ton)	Gas Price Forecast	Load Growth Scenario
10	29	$100	High	Medium

The analysis did not include alternative load growth scenarios because the portfolios were developed with the same load growth forecast. Therefore, applying alternative load forecasts would have no value for cost comparison purposes. The selection of only the June 2008 price forecast assumptions reflects a practical decision to help limit the number of additional model runs to a manageable number.

Risk Scenario Modeling Results

Table 8.34 shows the deterministic PVRR results for the 30 System Optimizer runs, along with the PVRR average and the standard deviation for each portfolio across the risk scenarios. The portfolio for case 8 has both the lowest PVRR and the smallest PVRR variability across the risk scenarios. The case 8 and 5 portfolios are nearly equal with respect to both PVRR average and standard deviation, owing to the similarity of the portfolios.

Table 8.34 – Scenario Risk PVRR Results

Risk Scenario Number	Case	Deterministic PVRR (Million 2008$)		
		Portfolio Case 5	Portfolio Case 8	Portfolio Case 9
1	1	21,025	21,972	21,048
2	2	22,176	22,305	22,188
3	3	22,550	21,288	22,481
4	5	40,542	40,730	40,542
5	8	41,691	41,389	41,672
6	14	44,243	42,430	44,146
7	17	52,533	51,782	52,489
8	22	55,159	53,144	55,049
9	24	64,853	63,379	64,768
10	29	65,123	62,913	64,915
Average		42,990	42,133	42,930
Standard Deviation		15,968	15,278	15,920

Table 8.35 reports the portfolio PVRR rankings for each risk scenario. Case 8 ranks first on the basis of having the lowest rank sum (16). Case 9 comes in second with a rank sum of 19, followed by case 5 with a rank sum of 24.

Table 8.35 – Portfolio PVRR Rankings

Risk Scenario Number	Case	Portfolio Rankings based on Deterministic PVRR		
		Portfolio Case 5	Portfolio Case 8	Portfolio Case 9
1	1	1	3	2
2	2	1	3	2

Risk Scenario Number	Case	Portfolio Rankings based on Deterministic PVRR		
		Portfolio Case 5	**Portfolio Case 8**	**Portfolio Case 9**
3	3	3	1	2
4	5	1	3	1
5	8	3	1	2
6	14	3	1	2
7	17	3	1	2
8	22	3	1	2
9	24	3	1	2
10	29	3	1	2
Rank Sum		24	16	19

Table 8.36 shows differences between the original deterministic PVRR and those obtained for the risk scenario runs.[52]

Table 8.36 – PVRR Differences, Portfolio Development Case less Risk Scenario Results

Risk Scenario Number	Case	Deterministic PVRR (Million 2008$)		
		Portfolio Case 5	**Portfolio Case 8**	**Portfolio Case 9**
Original PVRR		40,526	41,372	40,204
1	1	(19,501)	(19,400)	(19,156)
2	2	(18,350)	(19,067)	(18,016)
3	3	(17,976)	(20,084)	(17,723)
4	5	16	(642)	338
5	8	1,165	17	1,468
6	14	3,717	1,058	3,942
7	17	12,007	10,410	12,285
8	22	14,633	11,772	14,845
9	24	24,327	22,007	24,564
10	29	24,597	21,541	24,711

These results indicate that Portfolio 5 performed best in low gas/low CO_2 tax scenarios and performed worst in high gas price and high CO_2 tax cases. Portfolio 8 performed best under the medium/high gas price and medium/high CO_2 tax scenarios, but performed worst in low gas/low CO_2 scenarios.

Conclusions

The scenario risk assessment yielded findings similar to the stochastic mean cost analysis regarding the top-performing portfolio, case 8. However, case 9 performed slightly ahead of case 5 in the scenario risk analysis, whereas case 5 performed ahead of case 9 under the stochastic mean cost analysis. Given this outcome, the question is whether the risk scenario analysis, as formu-

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[52] Fixing of resources in System Optimizer for the risk scenario runs entailed rounding capacity values of the smaller resources, such as class 2 DSM amounts by topology bubble, price tier, and year. The result was a small PVRR difference with respect to the PVRR obtained in the original portfolio development run.

lated above, provides any added value for preferred portfolio selection over that provided by the stochastic analysis. PacifiCorp concludes that it does not. The reasons are as follows. First, the stochastic Monte Carlo simulations provide 100 combinations of input invariables, accounting for variable correlations. The scenario risk assessment is essentially a manually formulated and limited version of the Monte Carlo simulation. It is impractical to emulate this range of input variability using System Optimizer or the Planning and Risk model in deterministic mode.

Second, the scenario risk assessment introduces a confounding aspect to the preferred portfolio selection process given the situation where the analysis yields performance conclusions contradictory to those obtained from the stochastic analysis—such as with the case 5 and 9 portfolios.

In summary, PacifiCorp believes that the stochastic risk analysis is sufficient for exploring portfolio cost outcomes given a range of input assumptions reflecting uncertainty and risk. The only value that the scenario risk assessment provides is to confirm the degree that stochastic and deterministic costs are consistent for portfolio ranking purposes. On the other hand, the Company finds value with subjecting a portfolio to resource-specific scenarios as part of the acquisition path analysis, and using System Optimizer to determine the optimal resource mix under those alternate resource assumptions.

PORTFOLIO IMPACT OF THE 2012 GAS RESOURCE DEFERRAL DECISION

Based on the portfolio preference scores and consideration of relative resource risks, the Company would have chosen the case 5 portfolio as the basis for its preferred portfolio. However, due to the Company's February 2009 decision to terminate the construction contract for the Lake Side II CCCT resource, PacifiCorp conducted additional portfolio analysis to determine a revised preferred portfolio that takes this decision into account, as well as new transmission and market assumptions that supported that decision.

PacifiCorp conducted two types of portfolio studies reflecting the removal of Lake Side II as a planned resource in 2012. The first type involved fixing a combined-cycle gas plant in 2014 and running System Optimizer to select other resources using the case 5 input assumptions. Two portfolios were created: one had a 570 MW (July capacity) wet-cooled CCCT located at the Lake Side site in Utah North, while the second had a 536 MW dry-cooled CCCT located in the Currant Creek site. This was followed by stochastic production cost modeling runs using the PaR model with \$0, \$45, and \$100 CO_2 tax levels. These two portfolios reflect a CCCT deferral strategy that assumes, conservatively, that CCCT capital costs do not change from the generic values assumed for the 2008 IRP, after adjusting for inflation.[53] The rationale for fixing CCCTs in System Optimizer is that this model does not account for resource optionality and reserve holding value captured through stochastic production cost modeling, and tends to favor SCCTs over CCCTs for meeting capacity planning reserve margins as a result.

The second portfolio study type consisted of the removal of the Lake Side II plant in the top eight portfolios selected on the basis of the preference scores (Table 8.36), and having System

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[53] PacifiCorp expects that lower commodity costs and the effects of the world-wide economic downturn should eventually start to impact plant construction prices. However, the Company did not see price reductions in the bids received in response to its 2008 All-Source RFP issued in October 2008.

Optimizer select the portfolios to fill the resource gap using the case definitions associated with these portfolios. Stochastic production cost simulations with multiple CO_2 tax levels were also conducted for these 10 portfolios.

The portfolios modeled without Lake Side II reflect a number of assumption changes documented in Chapters 6 and 7. Table 8.37 profiles the 10 portfolios and the associated input assumptions.

Table 8.37 – Additional Portfolios Modeled to Support a 2012 Gas Resource Deferral Strategy

Portfolio Name	Case Definition Used	Additional Fixed Resources	Common Assumption Changes
2B	2	None	● Lake Side II CCCT removed as a planned resource ● West Main/West Main to Yakima topology updates (See Figure 7.2) ● Mona to Utah South topology update (See Figure 7.2) ● Mid-Columbia market depth updates for 2012 and 2013 (See Table 6.22) ● Mona market depth updates for 2012 and 2013, including Nevada Utah Border (See Table 6.22)
5B	5	None	
5B_CCCT_Dry	5	Dry-cooled CCCT fixed in 2014	
5B_CCCT_Wet	5	Wet-cooled CCCT fixed in 2014	
8B	8	None	
9B	9	None	
10B	10	None	
17B	17	None	
18B	18	None	
47B	47	None	

PacifiCorp developed a full set of performance measures for these portfolios and ranked them using the same preference-scoring scheme applied for the original 21 portfolios. These additional portfolios are shown in Appendix A. The stochastic performance measures are reported in Appendix B.

Table 8.38 compares the cumulative nameplate capacities by major resource type for the original and "B series" portfolios. The B series portfolios include more front office transaction and energy efficiency program capacity than their original portfolio counterparts, and—with the exception of the two fixed CCCT portfolios (5B_CCCT_Dry and 5B_CCCT_Dry)—include more IC Aero SCCT capacity. On the other hand, just four of the 10 portfolios include more wind capacity (2B, 10B, 17B, and 47B), while two portfolios have less wind than the original portfolios (8B and 18B). Portfolio tables showing the resource capacity differences between the ten B series portfolios and the corresponding originals are included in Appendix A.

Table 8.38 – Resource Capacity Comparisons, Original and B Series Portfolios

	Cumulative Nameplate Capacity for 2009-2028 (MW) by Resource Type						
Case	**Wind**	**CCCT**	**IC Aero SCCT**	**FOT [1/]**	**DSM, Class 2**	**Dist Gen [2/]**	**Clean Coal Retrofit**
2	1,204	607	261	646	1,815	50	0
2B	1,863	0	548	775	1,866	92	0
5	1,863	607	261	691	1,835	50	346

	Cumulative Nameplate Capacity for 2009-2028 (MW) by Resource Type						
Case	**Wind**	**CCCT**	**IC Aero SCCT**	**FOT** [1/]	**DSM, Class 2**	**Dist Gen** [2/]	**Clean Coal Retrofit**
5B	1,863	0	391	829	1,896	132	0
5B_CCCT_Dry	1,863	536	261	821	1,839	78	346
5B_CCCT_Wet	1,863	570	261	820	1,838	50	346
8	2,663	607	0	663	1,942	88	0
8B	2,563	0	261	811	1,989	129	0
9	1,863	607	261	690	1,834	50	346
9B	1,863	0	391	829	1,893	132	0
10	2,863	607	0	679	1,936	57	0
10B	2,952	0	261	820	1,985	127	0
17	4,163	607	0	613	2,020	50	346
17B	4,363	0	261	796	2,063	127	346
18	4,163	607	0	640	1,974	50	346
18B	3,863	0	261	808	2,023	127	346
47	1,607	607	174	646	1,822	92	0
47B	2,383	0	609	797	1,855	92	0

[1/] Annual average front office transactions capacity for 2009-2018 shown.

[2/] Distributed generation consists of customer standby generation and combined heat and power facilities.

General findings for this additional portfolio analysis are as follows.

- The combination of revised input assumptions and deferral of a 2012 gas resource resulted in lower PVRRs compared with those reported for the original portfolios. For example, as shown in Table 8.39, the stochastic mean PVRR of portfolio 5B (averaged across the three CO_2 tax simulations) is $570 million less than the PVRR for the original case 5 portfolio.[54]

- The portfolio with a wet-cooled CCCT located at the Lake Side II site ("5B_CCCT Wet") had the lowest risk-adjusted PVRR, CO_2 cost exposure, and rate impact (Table 8.40). The other two case 5 portfolios ranked second and third.

- The wet-cooled CCCT deferral portfolio also had the best overall preference score, ranking at the top for expected value CO_2 tax levels of $20 through $60. Table 8.41 presents the portfolio preference scores for CO_2 tax expected values from $15 to $70.

- The three portfolios developed with the case 5 input assumptions had the highest preference scores (Table 8.41). This portfolio analysis strengthens the assertion that case 5 is relatively robust at producing the optimal portfolios on the basis of overall preference scoring.

- Fixing a CCCT in 2014 rather than allowing System Optimizer to fully optimize resource selection resulted in improved stochastic costs. For example, fixing a wet-cooled CCCT in 2014 yielded a $115 million improvement in risk-adjusted PVRR (averaged across the $0,

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[54] The PVRRs for the original case 5 portfolio reported in Table 8.41 are adjusted to include 2012 CCCT capital costs for comparability with the gas resource deferral portfolios. Because the Lake Side II CCCT was treated as an existing resource in all the original portfolios, associated capital costs were not included in the PVRR calculations.

$45, and $100 CO_2 tax simulations) relative to portfolio 5B, which has no CCCT. Fixing a dry-cooled CCCT in 2014 resulted in a $51 million risk-adjusted PVRR improvement.

- The tail risk (upper-tail mean PVRR) for the B series portfolios is lower than that for the original portfolios, accounting for the capital cost of the Lake Side II resource (See footnote no 49). This is generally due to more wind, DSM, and distributed generation in these new portfolios. The two CCCT deferral portfolios had the highest upper-tail risk and production cost standard deviation among the B series portfolios. Figure 8.26 is a scatter-plot graph of the stochastic mean PVRR versus upper-tail mean PVRR for the three CO_2 tax levels. (Table B.23 in the appendix volume shows portfolio ranking results for an alternate importance weighting scheme that includes the upper-tail mean PVRR as a performance measure with a relatively large importance weight: 20%.)

Table 8.39 – Stochastic Mean PVRR for 2012 Gas Resource Deferral Strategy Portfolios

Case	CO2 Tax Level			Average	Rank
	$0/Ton	$45/Ton	$100/Ton		
2B	22,126	40,062	60,448	40,879	8
5B	22,554	39,452	58,664	40,224	3
5B_CCCT_Dry	22,462	39,369	58,751	40,194	2
5B_CCCT_Wet	22,457	39,315	58,639	40,137	1
8B	23,402	39,673	57,809	40,295	4
9B	22,778	39,725	59,031	40,511	5
10B	23,921	40,261	58,542	40,908	8
17B	25,569	40,539	56,798	40,968	9
18B	25,102	40,353	57,136	40,864	6
47B	22,658	40,507	60,872	41,346	10
5 [1/]	23,075	39,947	59,358	40,794	

[1/] The PVRRs for the original case 5 portfolio are adjusted to include 2012 CCCT capital costs for comparability with the gas resource deferral portfolios.

Table 8.40 – Measure Rankings and Preference Scores for 2012 Gas Resource Deferral Strategy Portfolios, $45/ton Expected-value CO_2 Tax

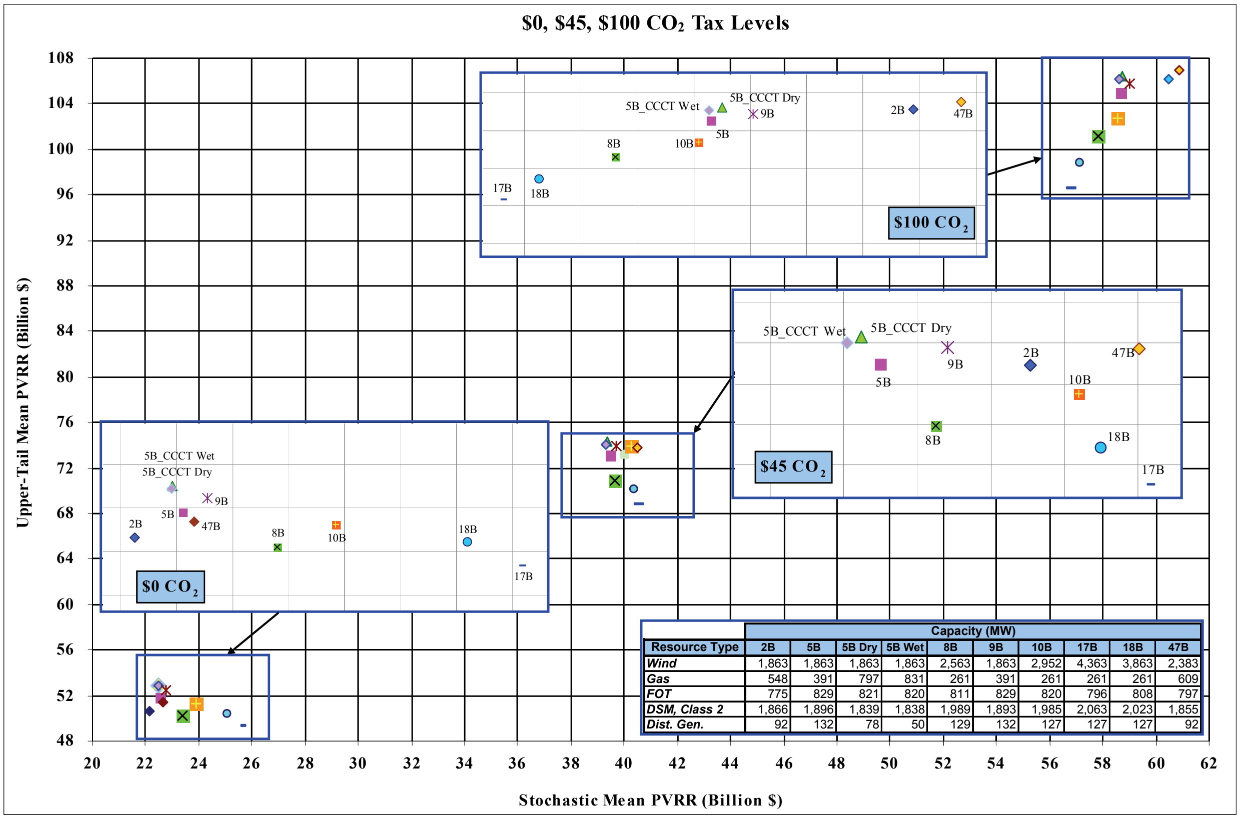
Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	6.5	8.9	1.0	6.0	8.0	1.2	1	**5.8**	**6.7**
5B	2.0	2.7	3.0	3.0	8.5	7.5	6.3	**2.7**	**2.8**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.8**	**1.7**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	2.9	4.8	6.4	4.0	5.2	4.9	4.5	**3.7**	**4.0**
9B	4.2	2.3	3.2	5.0	9.0	10.0	10.0	**4.3**	**4.8**
10B	7.8	10.0	5.7	7.0	5.8	5.3	6.8	**7.5**	**8.9**
17B	8.8	8.9	10.0	9.0	1.0	1.1	2.2	**7.8**	**9.3**
18B	7.9	8.1	8.2	8.0	2.9	3.3	2.2	**7.1**	**8.4**
47B	10.0	9.2	1.2	10.0	8.3	1.0	7.4	**8.3**	**10.0**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

Table 8.41 – Measure Rankings and Preference Scores for 2012 Gas Resource Deferral Strategy Portfolios

	Expected Value CO2 Tax													Normalized
Case	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**	**Rank Sum**	**Score**
2B	1.2	1.8	2.3	2.9	4.2	5.4	6.7	7.6	7.8	7.9	8.0	8.3	63.9	6.8
5B	2.2	2.1	2.2	2.3	2.4	2.6	2.8	2.8	2.9	2.8	3.2	3.9	32.2	3.2
5B_CCCT Dry	1.3	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.6	1.7	2.1	2.9	20.1	1.8
5B_CCCT Wet	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	2.3	13.3	1.0
8B	4.5	4.6	4.4	4.4	4.3	4.1	4.0	3.4	2.7	1.7	1.3	2.1	41.7	4.3
9B	3.3	3.4	3.5	3.7	3.8	4.4	4.8	4.6	4.5	4.8	4.7	5.3	50.8	5.3
10B	6.6	6.8	7.1	7.4	7.9	8.4	8.9	8.2	7.4	6.7	6.2	6.2	87.8	9.6
17B	10.0	10.0	10.0	10.0	10.0	10.0	9.3	6.9	5.1	3.1	1.5	1.0	86.9	9.5
18B	8.9	8.9	8.9	8.9	8.9	9.0	8.4	6.2	4.8	3.4	1.9	1.7	79.8	8.7
47B	3.3	3.8	4.5	5.3	6.4	8.0	10.0	10.0	10.0	10.0	10.0	10.0	91.4	10.0

Figure 8.26 - Stochastic Cost versus Upper-tail Risk: \$0, \$45, and \$100 CO_2 Tax Levels



	Capacity (MW)									
Resource Type	**2B**	**5B**	**5B Dry**	**5B Wet**	**8B**	**9B**	**10B**	**17B**	**18B**	**47B**
Wind	1,863	1,863	1,863	1,863	2,563	1,863	2,952	4,363	3,863	2,383
Gas	548	391	797	831	261	391	261	261	261	609
FOT	775	829	821	820	811	829	820	796	808	797
DSM, Class 2	1,866	1,896	1,839	1,838	1,989	1,893	1,985	2,063	2,023	1,855
Dist. Gen.	92	132	78	50	129	132	127	127	127	92

WIND RESOURCE ACQUISITION SCHEDULE DEVELOPMENT

Based on the 2012 gas resource deferral modeling results, PacifiCorp chose the "5B_CCCT_Wet" portfolio as the basis for the preferred portfolio. An issue with this portfolio, and wind resource optimization in general, is that the capacity expansion model adds a large amount of wind capacity in certain years and little or none in others. Such a pattern, while optimal from the model's perspective, is not desirable from a business planning perspective.

As noted in Chapter 7, PacifiCorp applied annual wind capacity constraints to reflect realistic system limits. However, additional constraints are required to emulate a long-term procurement program that ideally accounts for rate stability/financial impacts, anticipated demand for construction and equipment resources, flexibility to respond to changing market and regulatory conditions, construction management requirements, and location-specific considerations not factored into the IRP models. The Company believes that given the current sophistication of capacity expansion optimization models, development of a suitable wind acquisition schedule that takes these various factors into account is best handled outside of the model. Consequently, PacifiCorp manually developed a wind acquisition schedule based on the aggregate wind amount from the 5B_CCCT_Wet portfolio, and then ran System Optimizer with this fixed wind schedule and the 5B_CCCT_Wet input assumptions. The resulting portfolio, presented in the next section, constitutes PacifiCorp's preferred portfolio. Table 8.42 shows the wind acquisition schedule and original wind additions from the 5B_CCCT_Wet portfolio.

Table 8.42 – Revised Wind Resource Acquisition Schedule

Wind Resource Acquisition Schedule (Capacity, MW)														
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total (2009-2018)**	**Total (2009-2021)**
East	198	150		100	100	100	150	100	100	50	200	200	150	1,048	1,598
West	45	20	200											265	265
Total	243	170	200	100	100	100	150	100	100	50	200	200	150	1,313	1,863
Wind Additions for Case 5B_CCCT_Wet															
East	99	99					300			750	550			598	1,798
West	45	20												65	65
Total	342	119				140	460	100		750				1,261	1,863

The strategy behind this acquisition schedule is to distribute wind quantities across all years of the business planning period (2009-2018) and through 2021, keeping annual amounts at 200 MW or less. Planning to relatively level annual wind additions provides the following customer and Company benefits:

- Helps to support rate and capital spending stability
- Strikes a balance between the risk of (1) front-loading wind development and then experiencing lower-than-expected CO_2 costs, and (2) deferring wind development and then experiencing higher-than-expected CO_2 costs, termination of the PTC after 2012, or both
- Reduces the risk of RPS compliance penalty costs stemming from procurement delays for projects needed to meet percentage-of-sales requirements in a given year
- Helps in maintaining efficiently sized construction management, engineering, and support teams

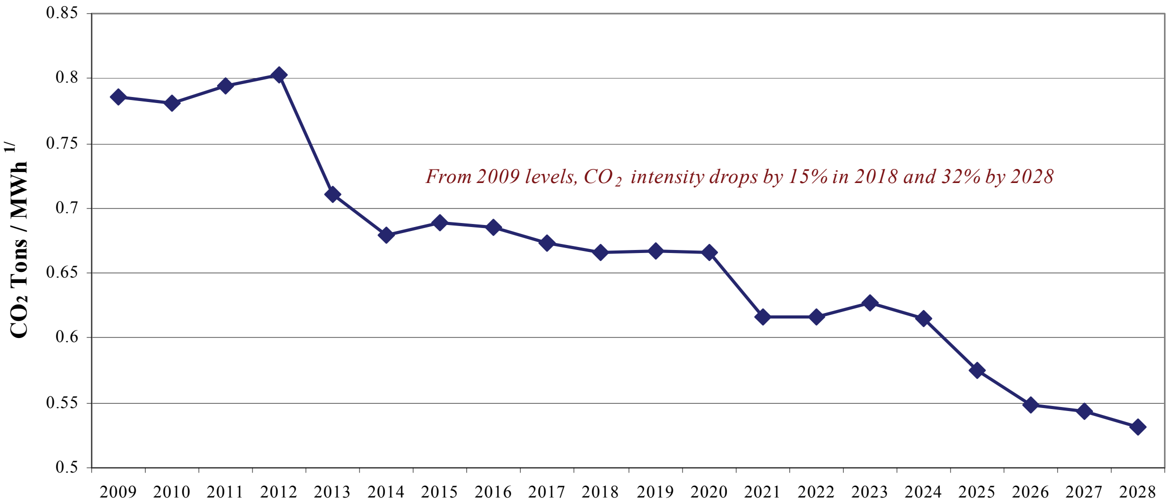
The wind schedule also reflects the addition of 200 MW of west-side wind resources in 2011 to take advantage of regional wind diversity benefits that are not captured in the IRP models.

THE IRP PREFERRED PORTFOLIO

The increasing mix of clean resources reflected in the 2008 IRP preferred portfolio—renewables and demand-side management—reduces the carbon intensity of PacifiCorp's generation fleet (Figure 8.27) and positions the Company well for meeting future climate change and renewable resource requirements. For example, the preferred portfolio exceeds current jurisdictional RPS requirements expressed on a system load basis, and would potentially meet a 15-percent federal RPS requirement such as the one contained in draft legislation proposed by U.S. Representatives Waxman and Markey ("The American Clean Energy and Security Act of 2009"). The addition of energy efficiency resources—reaching 4.2 million kWh by 2018—reduces the system coincident peak load from a 2.7% average annual growth rate (2009-2018) to 1.9%.

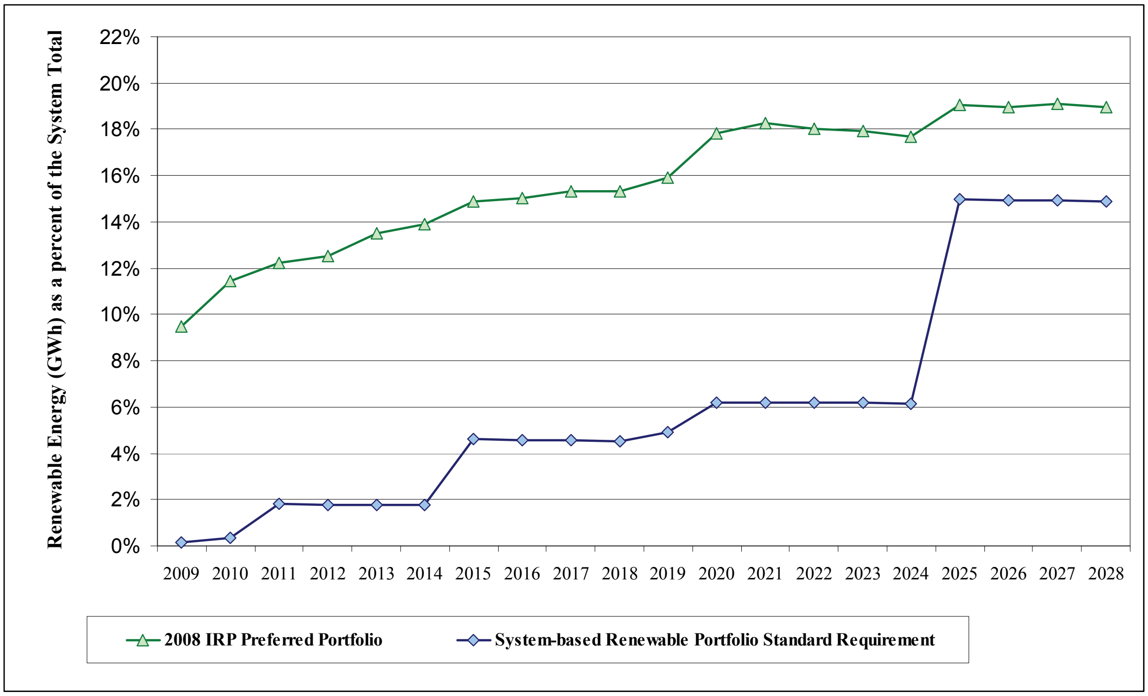
The addition of flexible natural gas resources supports the aggressive expansion of intermittent renewable generation while meeting incremental base load and intermediate load needs. The role of new firm market purchases is to help replace expiring long-term power purchases, and, by adjusting volumes up or down, provide resource flexibility to manage the volatility and uncertainty in load forecasts, commodity prices, and capital costs. The increase in near-term front office transactions takes advantage of the significant price drops in fuels and forward wholesale power in late 2008 and early 2009, providing the opportunity to lower power supply costs before the Company needs to commit to a large new thermal power plant. If construction markets continue to soften as several experts predict, this will create additional cost-saving opportunities through lower plant prices.

Figure 8.27 – Carbon Dioxide Intensity of the 2008 IRP Preferred Portfolio



[1/] Generation consists of the output from thermal, renewable and hydro resources based on a $45/ton CO_2 tax beginning in 2013.

Figure 8.28 – Renewable Portfolio Standard Compliance 2008 IRP Preferred Portfolio



Relative to the preferred portfolio reported in the 2007 IRP Update report (June 2008), the 2008 preferred portfolio relies on significantly less firm market purchases for the period covered in common (2009-2017). For gas resources, the major difference is the addition of a simple-cycle gas plant in 2016; with the acquisition of the Chehalis plant in 2008, there is negligible change in the amount of combined-cycle gas capacity. The 2008 IRP relies more heavily on distributed generation resources, while differences in wind and Class 2 DSM are minimal. Table 8.43 shows the annual resource differences for the two preferred portfolios (2008 IRP less the 2007 IRP Update).

Table 8.43 – Resource Differences, 2008 IRP Preferred Portfolio less 2007 IRP Update Preferred

		Capacity, MW											Total
	Resource	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2008-2017**
East	Gas Combined Cycle (2x1)		-	-	-	(1,096)	-	570	-	-	-	-	(526)
	IC Aero SCCT		-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement		-	-	-	201	-	-	-	-	-	-	201
	Coal Plant Turbine Upgrades		(18)	7	(5)	(12)	2	14	-	8	-	-	(4)
	Geothermal, Blundell 3		-	(35)	-	-	35	-	-	-	-	-	-
	Wind	36 [2]	(201)	149	(100)	(100)	100	(100)	150	100	100	50	134
	Distributed Generation		6	(13)	6	6	6	6	8	8	8	8	42
	Firm Market Purchases		75	50	150	279	(140)	(546)	(598)	(572)	(66)	800	NA
West	Chehalis CCCT	509 [2]	-	-	-	-	-	-	-	-	-	-	509
	Coal Plant Turbine Upgrades		-	(8)	(9)	(5)	(5)	-	-	-	-	-	(28)
	Swift Hydro Upgrades*		-	-	-	-	-	-	-	-	-	-	-
	Wind	139 [2]	45	20	-	-	(100)	-	-	-	-	-	104
	Distributed Generation		2	2	2	2	3	3	3	3	3	3	25
	Firm Market Purchases	(400)	(400)	(657)	(677)	(311)	30	(55)	(100)	(333)	(609)	582	NA
DSM [3]	Energy Efficiency (Class 2 DSM)	(67)	2	2	(2)	(3)	1	2	3	2	5	87	(55)

[1] Acquisition of the Chehalis 509 MW combined-cycle plant in Washington.

[2] For 2008, actual wind additions totaled 545 MW, compared to the planned amount of 370 MW in the 2007 IRP Update

[3] Expansions of the existing Utah Cool Keeper program and dispatchable irrigation programs are treated as existing resources. Relative to the 2007 IRP Update quantities, the incremental DSM planned expansions reach 525 MW by 2018.

[4] For the 2007 IRP Update, Class 2 DSM was treated as a decrease to load rather than as a resource included in the preferred portfolio.

Table 8.44 presents the detailed view of the preferred portfolio resources. This portfolio reflects the wind schedule described in the preceding section. Since Class 1 DSM other than the Utah Cool Keeper program was found to be cost-effective in all the portfolios modeled, the preferred portfolio includes up to 120 MW of additional cost-effective Class 1 DSM to be identified through competitive Requests for Proposals and procured in the 2009-2018 time frame. (For the non-CCCT "B series" cases, the capacity expansion model typically selected 91 MW of various Class 1 DSM programs in the east—predominantly irrigation load control and load curtailment—and 34 MW in the west.) This amount is in line with the corporate objective of aggressively pursuing DSM opportunities, and exceeds the 2009 business plan goal by 15 MW. Acquiring the additional Class 1 DSM amounts would reduce the need for front office transactions.

Below are explanatory notes for the portfolio table.

- Swift 1 Upgrades – The three Swift upgrade projects (25 MW each) are shown under the year for which they enter commercial service (2012, 2013, and 2014); however, the planned in-service dates occur after the system peaks for these years. They are available to support the summer peak load in 2013, 2014, and 2015, respectively.
- High Plains and Duke PPA Wind Projects – The High Plains wind project has an October December 2009 in-service date, and is therefore shown under the year for which it enters commercial service (2009); the Duke project has a December 2009 in-service date, but is modeled with a start date of January 1, 2010, and is therefore shown in the year it is available to support the summer peak load (2010).
- Gas resource MW capacities reflect average annual capability rather than the generator nameplate. For the CCCT, the value shown approximates the July maximum capability.
- Class 2 DSM resource capacities reflect summer peak values.
- The capacities shown for the coal plant CCS (carbon capture and sequestration) retrofit resources represent replacement capacities for the existing units. The replacement capac-

ity is smaller than the original unit size, which is due to a capacity penalty for capturing the CO_2.

- Front office transactions and growth resources reflect amounts acquired for the given year only, and are not cumulative.
- For the 20-year totals column, growth resources are reported as an eight-year average from 2021-2028.
- Short-term resource totals comprise the sum of front office transactions and growth resources.

Table 8.45 shows the resulting capacity load and resource balance for 2009-2018 with preferred portfolio resources included. Wind and 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 Table 8.44. Figures 8.29 and 8.30 consist of pie charts showing the energy and capacity mixes of the portfolio for 2009, 2014, and 2018. (Note that for the capacity charts, the expected system peak capacity contribution for wind resources is shown.)

Table 8.44 – Preferred Portfolio, Detail Level

		Capacity, MW																				Resource Total	
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**10 Year**	**20 Year**
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	CCCT F 2x1	-	-	-	-	-	570	-	-	-	-	-	-	-	-	-	-	-	-	-	-	570	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell Geothermal 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, High Plains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35% Capacity Factor	-	150	-	100	100	100	150	100	100	50	200	200	150	-	-	-	-	-	-	-	850	1,400
	Total Wind	**99**	**249**	**-**	**100**	**100**	**100**	**150**	**100**	**100**	**50**	**200**	**200**	**150**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,048**	**1,598**
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, Utah-Cool Keeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	-	-	-	-	-	-	-	-	-	-	Up to 90	Up to 90
	DSM, Class 2, Goshen	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, Utah	40	46	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	447	971
	DSM, Class 2, Wyoming	-	3	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	68	164
	DSM, Class 2 Total	**42**	**51**	**49**	**52**	**55**	**55**	**56**	**56**	**58**	**59**	**58**	**59**	**60**	**62**	**64**	**64**	**71**	**67**	**69**	**67**	**532**	**1,173**
	FOT Utah, 3rd Qtr HLH	-	-	-	44	50	-	2	28	-	-	-	7	50	50	50	50	-	-	50	-		
	FOT Mead, 3rd Qtr HLH	-	-	-	-	-	-	-	-	517	600	600	600	600	600	600	600	600	600	600	600		
	FOT Mona/Nevada Utah Border, 3rd Qtr HLH	75	50	150	350	443	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-		
	FOT East Total	**75**	**50**	**150**	**394**	**493**	**200**	**202**	**228**	**717**	**800**	**800**	**807**	**650**	**650**	**650**	**650**	**600**	**600**	**650**	**600**		
	Growth Resource - Goshen	-	-	-	-	-	-	-	-	-	-	-	-	204	187	198	219	-	-	192	-		
	Growth Resource - Utah North	-	-	-	-	-	-	-	-	-	-	-	-	212	308	238	242	-	-	-	-		
	Growth Resource - Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	73	79	126	167	-	-	196	-		
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, Yakima, 29% Capacity Factor PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Walla Walla, 29% Capacity Factor PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	**45**	**20**	**200**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**265**	**265**
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	25	-	-	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	-	-	-	-	-	-	-	-	-	-	Up to 30	Up to 30
	DSM, Class 2, Washington	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, West Main	28	28	30	30	30	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, Yakima	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	**35**	**36**	**39**	**39**	**38**	**39**	**39**	**39**	**39**	**29**	**29**	**29**	**30**	**29**	**29**	**30**	**29**	**30**	**30**	**30**	**372**	**665**
	FOT COB, Flat Annual	-	-	59	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-		
	FOT COB, 3rd Qtr HLH	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338		
	FOT Mid-Columbia, Flat Annual	-	-	-	-	-	-	-	-	-	171	228	228	37	67	71	63	68	87	109	165		
	FOT Mid-Columbia, 3rd Qtr HLH	-	-	-	400	400	300	400	400	-	121	105	160	-	-	-	7	308	313	291	235		
	FOT West Main, 3rd Qtr HLH	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50		
	FOT West Total	**-**	**-**	**59**	**839**	**839**	**739**	**739**	**689**	**289**	**582**	**721**	**776**	**424**	**454**	**459**	**457**	**764**	**788**	**788**	**788**		
	Growth Resource - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	106	97	134	135	127	128	396	403		
	Growth Resource - West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	660	67	666		
	Growth Resource - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	157	163	268	271	215	294	315	317		
	Annual Additions, Long Term Resources	**257**	**467**	**378**	**491**	**286**	**823**	**266**	**485**	**218**	**158**	**289**	**291**	**243**	**94**	**94**	**95**	**471**	**97**	**123**	**97**		
	Annual Additions, Short Term Resources	**75**	**50**	**209**	**1,234**	**1,332**	**939**	**942**	**918**	**1,006**	**1,382**	**1,521**	**1,583**	**1,825**	**1,937**	**2,074**	**2,141**	**2,313**	**2,470**	**2,603**	**2,773**		
	Total Annual Additions	**332**	**517**	**587**	**1,725**	**1,618**	**1,762**	**1,208**	**1,402**	**1,224**	**1,540**	**1,811**	**1,873**	**2,068**	**2,031**	**2,168**	**2,236**	**2,785**	**2,567**	**2,727**	**2,870**		

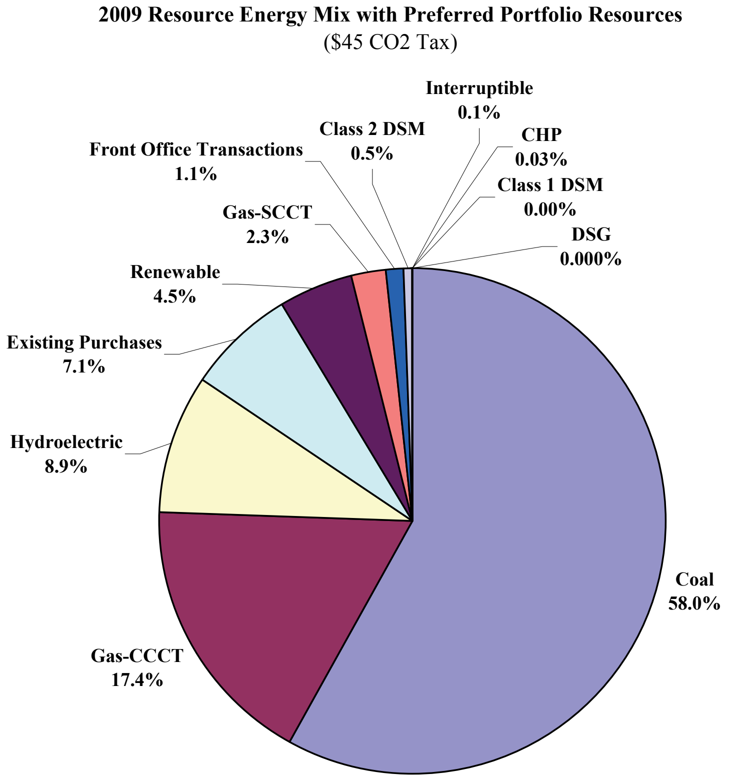
* Up to 120 MW of additional cost-effective Class 1 DSM programs (90 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced accordingly

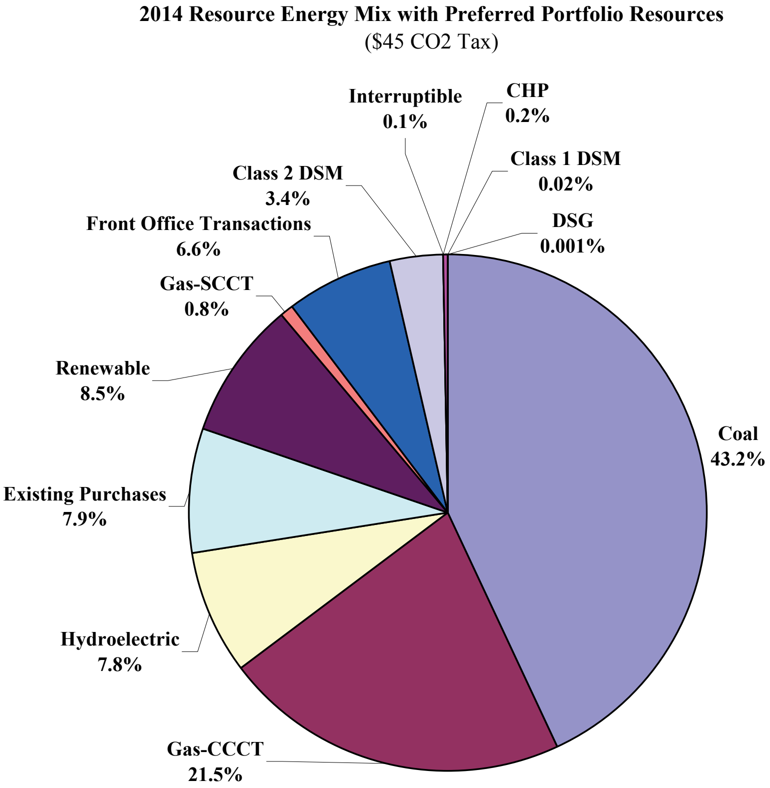
.

Table 8.45 - Preferred Portfolio Load and Resource Balance (2009-2018)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East										
Thermal	5,983	5,998	6,025	6,066	6,066	6,078	6,079	6,087	6,088	5,863
Hydroelectric Generation	135	135	135	135	135	135	135	135	135	135
Demand-side Management	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
Qualifying Facilities	151	151	151	151	151	151	151	151	151	151
Interruptible Contracts	237	237	237	237	237	237	237	237	237	237
Transfers	854	914	794	685	737	565	769	737	231	519
East Existing Resources	**8,614**	**8,534**	**8,476**	**8,238**	**8,300**	**8,149**	**8,361**	**8,326**	**7,831**	**7,905**
Combined Heat and Power	2	4	6	9	11	14	18	22	26	30
Distributed Standby Generation	4	8	12	15	19	23	27	31	35	38
DSM, Class 2	36	79	119	160	205	249	294	338	384	431
Front Office Transactions	75	50	150	394	493	200	202	228	717	800
Gas	0	0	0	201	201	771	771	1,032	1,032	1,032
Geothermal	0	0	0	0	35	35	35	35	35	35
Wind	9	12	12	15	17	20	23	26	28	29
Growth Resource	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**126**	**153**	**299**	**794**	**980**	**1,310**	**1,369**	**1,711**	**2,255**	**2,395**
East Total Resources	**8,740**	**8,687**	**8,774**	**9,032**	**9,280**	**9,460**	**9,730**	**10,037**	**10,086**	**10,300**
Load (Coincident Peak)	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	**7,538**	**7,717**	**7,908**	**8,151**	**8,388**	**8,524**	**8,774**	**9,048**	**9,150**	**9,355**
Planning reserves (12%)	731	769	771	786	797	841	865	890	837	845
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	**802**	**840**	**841**	**857**	**867**	**912**	**935**	**961**	**908**	**915**
East Obligation + Reserves	**8,339**	**8,556**	**8,749**	**9,007**	**9,255**	**9,436**	**9,709**	**10,009**	**10,058**	**10,271**
East Position	**401**	**131**	**25**	**25**	**25**	**24**	**21**	**28**	**29**	**29**
East Reserve Margin	**17.3%**	**13.7%**	**12.3%**	**12.3%**	**12.3%**	**12.3%**	**12.2%**	**12.3%**	**12.3%**	**12.3%**
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydroelectric Generation	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
Demand-side Management	0	0	0	0	0	0	0	0	0	0
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
Qualifying Facilities	120	120	120	120	120	120	120	120	120	120
Transfers	(855)	(914)	(795)	(686)	(738)	(565)	(769)	(737)	(231)	(520)
West Existing Resources	**4,530**	**4,281**	**3,958**	**3,198**	**3,217**	**3,392**	**3,300**	**3,325**	**3,815**	**3,551**
Combined Heat and Power	1	2	4	5	7	9	10	12	14	16
Distributed Standby Generation	1	2	4	5	6	7	8	9	11	12
DSM, Class 1	0	0	0	0	0	0	0	0	0	0
DSM, Class 2	26	54	83	112	140	169	199	228	257	279
Front Office Transactions	0	0	59	839	839	739	739	689	289	582
Other	0	0	0	0	0	0	0	0	0	0
Wind	0	0	8	8	8	8	8	8	8	8
Growth Resource	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**29**	**58**	**157**	**969**	**1,000**	**933**	**965**	**947**	**580**	**896**
West Total Resources	**4,559**	**4,340**	**4,115**	**4,167**	**4,217**	**4,325**	**4,265**	**4,272**	**4,395**	**4,448**
Load (Coincident Peak)	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	**3,892**	**3,912**	**3,780**	**3,845**	**3,896**	**3,980**	**3,927**	**3,932**	**4,001**	**4,086**
Planning reserves (12%)	307	319	346	334	333	355	345	348	401	370
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	**313**	**325**	**353**	**340**	**339**	**362**	**352**	**355**	**408**	**377**
West Obligation + Reserves	**4,199**	**4,230**	**4,126**	**4,179**	**4,229**	**4,335**	**4,272**	**4,280**	**4,402**	**4,456**
West Position	**360**	**110**	**(11)**	**(12)**	**(12)**	**(10)**	**(7)**	**(8)**	**(7)**	**(9)**
West Reserve Margin	**21.1%**	**14.6%**	**11.5%**	**11.5%**	**11.5%**	**11.6%**	**11.7%**	**11.6%**	**11.7%**	**11.6%**
System										
Total Resources	**13,299**	**13,027**	**12,889**	**13,199**	**13,497**	**13,785**	**13,995**	**14,309**	**14,481**	**14,747**
Obligation	**11,430**	**11,628**	**11,687**	**11,996**	**12,284**	**12,504**	**12,701**	**12,980**	**13,151**	**13,441**
Reserves	**1,115**	**1,165**	**1,194**	**1,197**	**1,206**	**1,274**	**1,287**	**1,316**	**1,315**	**1,292**
Obligation + Reserves	**12,544**	**12,793**	**12,882**	**13,192**	**13,490**	**13,777**	**13,988**	**14,296**	**14,466**	**14,733**
System Position	**754**	**234**	**7**	**7**	**6**	**7**	**8**	**13**	**15**	**14**

Figure 8.29 – Current and Projected PacifiCorp Resource Energy Mix





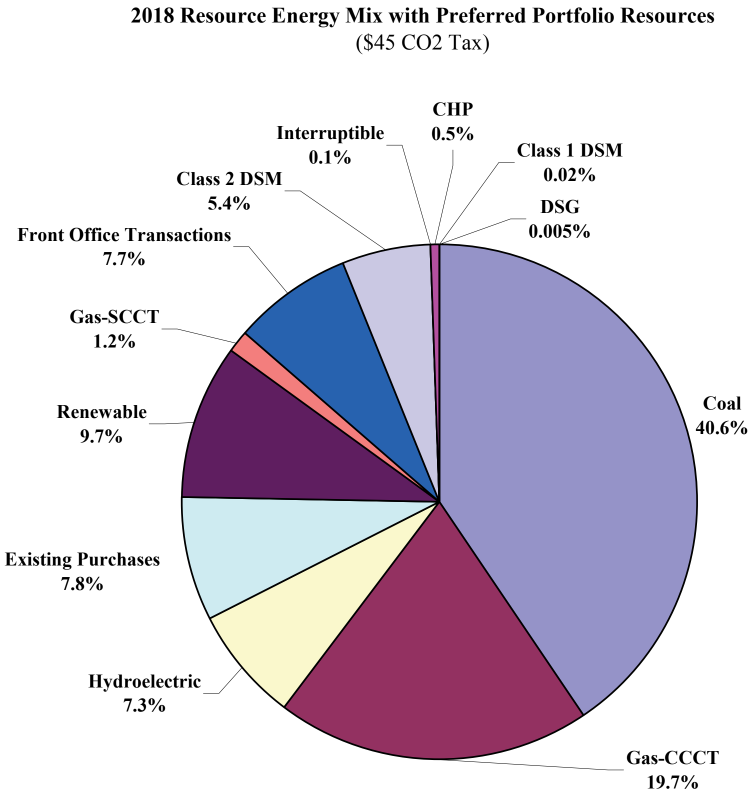
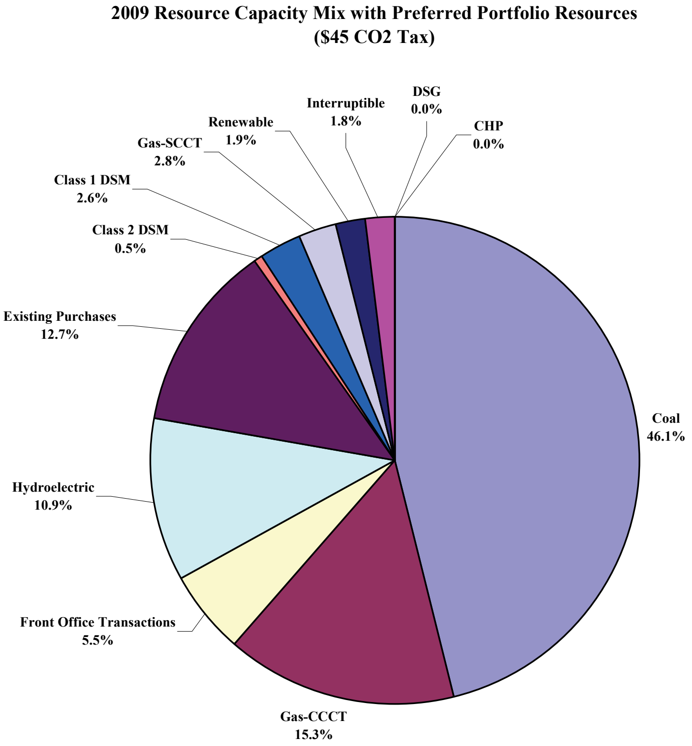
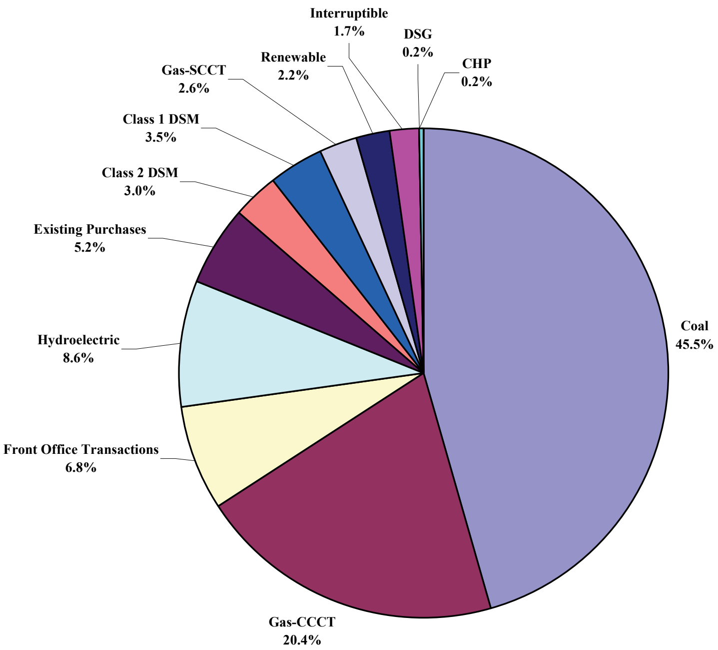

2018 Resource Energy Mix with Preferred Portfolio Resources
($45 CO2 Tax)

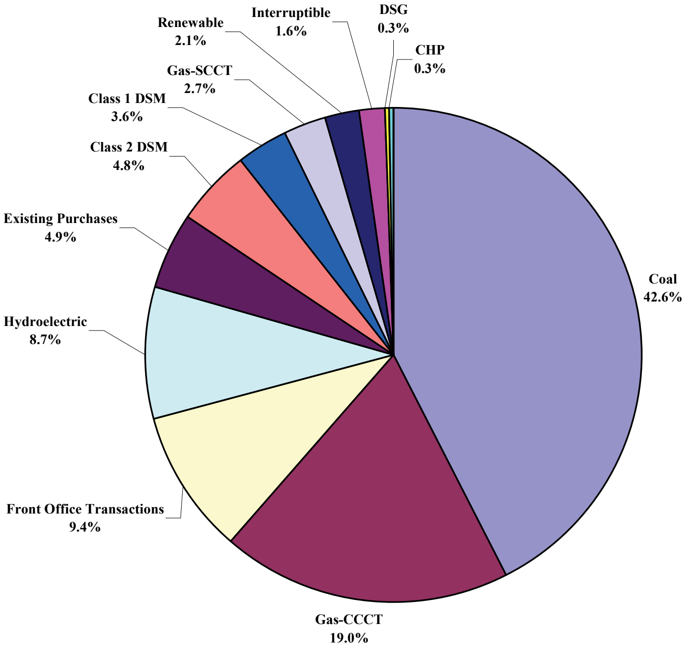
Figure 8.30 – Current and Projected PacifiCorp Resource Capacity Mix


2009 Resource Capacity Mix with Preferred Portfolio Resources
($45 CO2 Tax)

2014 Resource Capacity Mix with Preferred Portfolio Resources
($45 CO2 Tax)



2018 Resource Capacity Mix with Preferred Portfolio Resources
($45 CO2 Tax)



PORTFOLIO IMPACT OF PACIFICORP'S FEBRUARY 2009 LOAD FORECAST

PacifiCorp prepared a new load forecast in February 2009 after reviewing actual loads through January 2009. This forecast is being used to support corporate planning efforts including the acquisition path analysis outlined in the next Chapter, as well as recent regulatory filings.

Table 8.46 compares the coincident peak loads for the two load forecasts. For the 2009 business plan, the load forecast was adjusted to include the expected impact of historical Class 2 DSM programs, which are assumed to contribute incremental load reductions in the future as equipment and appliances are replaced with higher-efficiency alternatives. This load forecast adjustment was not included in previous IRP modeling, but is factored into the portfolio modeling using the February 2009 load forecast. As with the federal lighting standards adjustment described in Chapter 5, this DSM adjustment has the effect of increasing the load forecast for capacity expansion modeling only, so that the model can select additional DSM to fill the load gap. Including this adjustment also ensures that sufficient resource capacity is added in case the full amount of estimated future load reductions from existing Class 2 DSM programs is not realized. This adjustment, which partially offsets the recession-related load reductions, ranges from 34 MW in 2009 to 337 MW by 2018. Appendix E reports the detailed February 2009 forecast net of expected future load reductions attributable to existing Class 2 DSM programs and federal lighting standards.

Table 8.46 – Coincident Peak Load Forecast Comparison

Nov. 2008 Forecast	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
West	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
System	**10,150**	**10,371**	**10,640**	**10,991**	**11,281**	**11,501**	**11,798**	**12,127**	**12,384**	**12,674**
Feb. 2009 Forecast	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	6,722	6,924	7,220	7,483	7,741	7,905	8,173	8,410	8,664	8,886
West	3,265	3,324	3,379	3,447	3,491	3,554	3,608	3,624	3,719	3,793
System	**9,987**	**10,248**	**10,599**	**10,930**	**11,232**	**11,459**	**11,781**	**12,034**	**12,383**	**12,679**
Difference	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	(35)	(25)	70	79	98	126	144	107	173	190
West	(128)	(98)	(111)	(140)	(147)	(168)	(161)	(200)	(174)	(185)
System	**(163)**	**(123)**	**(41)**	**(61)**	**(49)**	**(42)**	**(17)**	**(93)**	**(1)**	**5**

Although the Company could not accommodate a comprehensive portfolio evaluation based on the February 2009 load forecast without contravening certain state IRP filing requirements, PacifiCorp was nevertheless able to conduct a preferred portfolio sensitivity analysis with it.

PacifiCorp developed a portfolio using this new DSM-adjusted load forecast and the case 5 input assumptions ($45/ton CO_2 tax and low June 2008 forward price curves) with the CCCT fixed in 2014. As indicated in table 8.45, the peak load reductions are not sufficient to eliminate or defer a gas combined-cycle plant.

The resource impacts of applying the new load forecast with the DSM adjustment described above, relative to the 5B_CCCT_Wet portfolio, are as follows:

- The IC aero SCCT originally added in 2016 is no longer needed
- Front office transactions are deferred in both the east and west, and decrease overall by about 100 MW by 2020; the east experiences a net increase of about 90 MW while the west experiences a net decrease of 185 MW in line with the lower loads
- To make up for the loss of the IC aero SCCT and front office transactions, the model added 41 MW of customer standby generation (30 MW in the east; 12 MW in the west), 50 MW of utility-scale biomass capacity in 2015-2016, and moved up 243 MW of wind from 2019 to 2017

Table 8.47 shows the resource capacity differences through 2020 between the portfolio produced using the new load forecast and the wet-cooled CCCT portfolio (5B_CCCT_Wet).

Table 8.47 – Resource Capacity Differences, February 2009 Load Forecast Portfolio less Wet-Cooled CCCT Portfolio

		Capacity, MW											
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East													
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-
	IC Aero	-	-	-	-	-	-	-	(261)	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	243	-	(243)	-
	CHP - Reciprocating Engine	-	-	1	-	-	-	-	-	-	-	-	-
	Distributed Standby Generation	4	4	4	4	4	4	4	4	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	(2.1)	-	-	-	-	-	-	-
	DSM, Class 2 Total	0.3	-	-	1.9	0.6	0.8	0.4	-	-	-	-	-
	FOT Utah, 3rd Qtr HLH	-	-	-	(30)	-	-	(17)	5	-	50	47	50
	FOT Mead, 3rd Qtr HLH	-	-	-	-	-	-	-	-	64	-	-	-
	FOT Mona/Nevada Utah Border, 3rd Qtr HLH	-	-	-	(7)	(74)	-	-	-	-	-	-	-
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-
West													
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	1	-	-	-	-	-	-	-	-
	Distributed Standby Generation	2	2	2	2	2	2	2	2	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	1.9	-	-	-	-
	DSM, Class 2 Total	-	-	-	-	1.1	0.5	-	-	-	-	-	-
	FOT Mid-Columbia, Flat Annual	-	-	(55)	-	-	-	-	-	-	-	-	-
	FOT Mid-Columbia, 3rd Qtr HLH	-	-	-	-	-	-	-	-	26	(17)	(22)	(19)
	FOT West Main, 3rd Qtr HLH	-	-	-	(44)	-	(71)	(58)	-	-	64	54	(42)
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-

Since the relative resource impact of the DSM-adjusted February 2009 load forecast is minimal until 2016, PacifiCorp decided to retain the IC aero SCCT in the preferred portfolio. Also supporting this decision is the uncertainty over the timing and pace of an economy recovery, combined with the short lead-time for a gas peaking resource and the potential need for such resources to support wind integration. Consideration of the timing and type of gas resources and other resource changes will be handled as part of a comprehensive assumptions update and portfolio analysis to be conducted for the next business plan and 2008 IRP update.

9. ACTION PLAN AND RESOURCE RISK MANAGEMENT

INTRODUCTION

PacifiCorp's 2008 IRP action plan identifies the steps the Company will take during the next two to four years to implement the plan, covering the 10-year resource acquisition time frame, 2009-2018. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions expected during the action plan time horizon and other events that could materially impact resource acquisition strategies.

The resources included in the 2008 IRP preferred portfolio were used to help define the actions included in the action plan, focusing on the size, timing, and type of resources needed to meet load obligations and current and potential future state regulatory requirements. The preferred portfolio resource combination was determined to be the lowest cost on a risk-adjusted basis accounting for cost, risk, reliability, and regulatory uncertainty.

The 2008 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study completion The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties. The current volatile economic and regulatory environment will likely require near-term alteration to resource plans as a response to specific events and improved clarity concerning the direction of the economy and government energy and environmental policies. For example, the economic stimulus package enacted in February 2009 ("The American Recovery and Reinvestment Act of 2009") introduced a number of provisions affecting resource planning, including extension and expansion of renewable and distributed energy technology tax benefits, funding of grid infrastructure improvements, and block grants for energy efficiency improvements. Provisions of the economic stimulus package, other than the renewable PTC extension, require more analysis to determine how they impact the Company and should be addressed within the IRP analytical framework. On the climate change mitigation front, the Waxman-Markey CO_2 cap-and-trade provisions are under investigation, but the Company is not able to determine the impact on resource plans until the legislation is finalized. Complicating the picture are state environmental/energy legislative proposals, such as Oregon's Senate Bill 80, that establish a state CO_2 cap-and-trade system.

Resource information used in the 2008 IRP, such as capital and operating costs, is consistent with that used to develop the Company's business plan completed in December 2008. However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost, and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

In addition to the action plan and acquisition path analysis, this chapter addresses a number of topics associated with resource risk management. These topics include the following:

- Managing carbon risk for existing plants

- The use of physical and financial hedging for electricity price risk
- Managing gas supply risk
- The treatment of customer and investor risks for resource planning

THE INTEGRATED RESOURCE PLAN ACTION PLAN

Table 9.1 is a summary of the annual MW capacity and timing for the resources contained in the 2008 IRP preferred portfolio. A more comprehensive summary of portfolio resources can be found in Chapter 8.

Table 9.1 – Preferred Portfolio, Summary Level

		Capacity, MW										Cumulative
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
East												
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-	200
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	128
	Geothermal	-	-	-	-	35	-	-	-	-	-	35
	Wind	99	249	-	100	100	100	150	100	100	50	1,048
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4	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	532
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800	
West												
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	42
	Swift Hydro Upgrades [2/]	-	-	-	25	25	25	-	-	-	-	75
	Wind	45	20	200	-	-	-	-	-	-	-	265
	CHP	1	1	1	1	2	2	2	2	2	2	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	372
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582	

[1/] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.

[2/] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

The 2008 IRP action plan, detailed in Table 9.2, provides the Company with a road map for moving forward with new resource acquisitions, including major transmission projects needed to support the preferred portfolio and other Company objectives. (More detail on transmission expansion action items is provided in Chapter 10.)

Table 9.2 – 2008 IRP Action Plan

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**	**2009 - 2018**	Acquire an incremental 1,400 MW of renewables by 2018, in addition to the already planned 75 MW of major hydroelectric upgrades in 2012-2014; PacifiCorp's projected renewable resource inventory by 2018 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 269 MW of wind resources in 2010 that are currently in the project pipeline, 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 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 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 solar and emerging technologies, government financial incentives, and procure 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 at the state and federal levels, and adjust the renewable acquisition timeline accordingly*
2	**Firm Market Purchases**	**2009 - 2013**	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until no sooner than the beginning of summer 2014 • Acquire the following resources: – Up to 1,400 MW of economic front office transactions on an annual basis as needed through 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) • Resources will be procured through multiple means: (1) reactivation of the suspended 2008 All-Source

Action Item	Category	Timing	Action(s)
			RFP in late 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 2009 load forecast • *Acquire incremental transmission through Transmission Service Requests to support resource acquisition*
3	**Peaking / Intermediate / Base-load Supply-side Resources**	**2012 - 2016**	Procure long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame • 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 in late 2009 – The Company plans to submit Company resources (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.*
4	**Plant Efficiency Improvements**	**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 2016, which are expected to add 128 MW of incremental in the east and 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*[55] • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules*
5	**Class 1 DSM**	**2009-2018**	Acquire at least 200 - 300 MW of cost-effective Class 1 demand-side management programs for implementation in the 2009-2018 time frame • *Pursue up to 200 MW of expanded Utah Cool Keeper program participation by 2018* • *Pursue up to 130 MW of additional cost-effective class 1 DSM products(90 MW in the east side and 30*

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

Action Item	Category	Timing	Action(s)
			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, 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.
6	**Class 2 DSM**	**2009-2018**	Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa • *Procure through the currently active DSM RFP and subsequent DSM RFPs*
7	**Class 3 DSM**	**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*
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 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
9	**Planning Process**	**2009-2010**	Portfolio modeling improvements • Complete the implementation of System Optimizer capacity expansion model enhancements for

Action Item	Category	Timing	Action(s)
	Improvements		improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level • 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 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 • Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for 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
10	**Transmission**	**2009-2011**	Obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona To 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
11	**Transmission**	**2010**	Permit and build Utah/Idaho/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief • Permit and construct a 345 kV line between Populus to Terminal
12	**Transmission**	**2012**	*Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Mona and Oquirrh*

Action Item	**Category**	**Timing**	**Action(s)**
13	**Transmission**	**2014**	*Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct 230 kV and 500 kV line between Windstar and Populus* • *Permit and construct a 345 kV line between Sigurd and Red Butte*
14	**Transmission**	**2016**	*Permit and build Northwest/Utah/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Populus and Hemingway*
15	**Transmission**	**2017**	*Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* • *Permit and construct a 500 kV line between Aeolus and Mona*

PROGRESS ON PREVIOUS ACTION PLAN ITEMS

This section describes progress that has been made on previous active action plan items documented in the 2007 Integrated Resource Plan Update report filed with the state commissions on June 11, 2008. Most of these action items have been superseded in some form by items identified in the current IRP action plan.

Action Item 1: Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources.

Status: PacifiCorp is on pace to exceed the 2,000 MW target by 2013. Since 2005, the Company's projected renewable resource inventory has grown by 1,405 MW, accounting for existing resources and those under construction, contract, or included in a capital budget. The incremental renewables identified in the 2008 IRP preferred portfolio and action plan bring the target to about 2,040 MW by 2013. The projected inventory exceeds 2,540 MW by 2018.

Action Item 2: Acquire the base Class 2 DSM (Pacific Power and Energy Trust of Oregon combined, including energy savings in Oregon beyond that funded by the ETO) of 300 MWa and 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Public Utility Commission of Oregon. PacifiCorp will reassess Class 2 objectives upon completion of system-wide DSM potential study. Will incorporate potentials study findings into the 2007 IRP update and 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.

> *Status: This action item has been superseded by Action Item no. 6 in Table 9.2. PacifiCorp issued a DSM RFP in November 2008 to help meet Class 1 DSM acquisition goals.*

Action Item 3: Targets were established through potential study work performed for the 2007 IRP. Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified. A new potential study was completed June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

> *Status: This action item has been superseded by Action Item no. 5 in Table 9.2. PacifiCorp developed Class 1 DSM supply curves using the DSM potentials study data, and incorporated them into the portfolio modeling for this IRP.*

Action Item 4: Although not currently in the base resource stack, the Company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. PacifiCorp will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes.

> *Status: This action item has been superseded by Action Item no. 7 in Table 9.2. PacifiCorp developed Class 3 DSM supply curves using the DSM potentials study data, and incorporated them into the portfolio modeling for this IRP. The all-source DSM RFP seeks price-responsive product proposals.*

Action Item 5: Pursue at least 75 MW of combined heat and power generation for the west-side and 25 MW for the east-side, to include purchase of combined heat and power output pursuant to PURPA regulations and from supply-side RFPs. The potential study results will be incorporated into the 2007 update and 2008 integrated resource planning processes.

> *Status: This action item has been superseded by Action Item no. 8 in Table 9.2. PacifiCorp has about 75 MW online of CHP/other distributed generation resources and 30-40 MW in the project pipeline.*

Action Item 6: [Distributed Generation] Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes.

> *Status: This action item has been successfully completed. Chapter 6 describes how PacifiCorp incorporated distributed generation resources in the 2008 IRP portfolio modeling process.*

Action Item 7: Procure base load / intermediate load / summer peak resources system-wide by the summer of 2012 through 2016. This is part of the requirement included in the 2012 Base Load RFP and the 2008 All Source RFP.

> *Status: This action item has been superseded by Action Item no. 3 in Table 9.2. PacifiCorp will reactivate the suspended 2008 All-Source RFP in late 2009 to assist in procuring the needed resources*

Action Items 8 through 12:

> *Status: These action items are no longer active.*

Action Item 13: Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability. Work with other transmission providers to facilitate joint projects where appropriate.

> *Status: This action item has been superseded by Action Item nos. 10 through 15 in Table 9.2. Chapter 4 and Chapter 10 outline the Company's transmission expansion plans.*

Action Item 14: Continue to have dialogue with stakeholders on Global Climate Change issues.

> *Status: PacifiCorp continues to participate in numerous forums that address these issues. PacifiCorp's Environmental Policy and Strategy department and Government Affairs de-*

> *partment are among the lead organizations within the Company that participate in ongoing policy dialogues.*

Action Item 15: Evaluate technologies that can reduce the carbon dioxide emissions of the Company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power. For the 2008 IRP, include integrated gasification combined cycle (IGCC) plants with carbon capture and sequestration as a resource option for selection.

> *Status: A variety of clean generating technologies were evaluated in this IRP, including a range of renewables, nuclear plants, and coal plants with carbon capture and sequestration (IGCC and conventional coal plant CCS retrofits).*

Action Item 16: Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system.

> *Status: This action item has been superseded by Action Item Nos. 1 and 9 in Table 9.2. PacifiCorp is currently updating its wind integration cost estimates, and will include the results as Appendix F in the separate appendix volume for the May 29 IRP filing. PacifiCorp is also pursuing operational improvements for integrating wind resources. This activity is briefly described in the Resource Procurement Strategy section below.*

Action Item 17: Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. PacifiCorp has successfully updated modeling assumptions, including detailed representation of state RPS requirements as system load-based constraints. See Chapter 7 for details on the modeling approach for representing RPS compliance and CO_2 costs.*

Action Item 18: Work with states to gain acknowledgement or acceptance of the 2008 integrated resource plan and action plan. To the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs.

> *Status: Activity under this action item will commence after filing of the 2008 IRP with the state commissions.*

Action Item 19: In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. In formulating market purchase options for the IRP models, the Company lacked information with which to discriminate such purchases from the proxy front office transaction (FOT) resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the 2008 All-Source RFP to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received*

> *no intermediate-term market purchase bids; therefore, such resources could not be reasonably modeled for this IRP. (See Chapter 6, "Resource Options") PacifiCorp will continue to investigate the formulation of satisfactory intermediate-term market purchases for portfolio modeling contingent on acquiring suitable market data.*

Action Item 20: For the 2008 IRP, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.

> *Status: This action item was successfully completed. PacifiCorp designed a portfolio analysis to address this requirement, estimating a system-wide hard cap based on Oregon's HB 3543 emission reduction goals. A description of this portfolio scenario ("case 40") is provided in Chapter 7; modeling results are provided in Chapter 8.*

Action Item 21: For the 2008 IRP, further develop with stakeholders, use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. The Company will investigate functionality in the System Optimizer model that allows the application of an LOLP constraint for capacity planning.*

Action Item 22: For the 2008 IRP, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.

> *Status: This action item has been successfully completed. PacifiCorp incorporated existing plant retrofits with carbon capture and sequestration technology as capacity expansion model resource options. Additionally, portfolios were developed to simulate the effect of forced coal plant back-down through high CO_2 costs and emissions hard cap constraints. The associated analysis is provided in Chapter 8.*

Action Item 23: Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emission rates to short-term market transactions.

> *Status: This action item has been superseded by Action Item no. 9 Table 9.2, which highlights the CO_2 modeling enhancements that PacifiCorp is currently in the process of implementation with its model software vendor, Ventyx Energy, LLC. Completion of the software enhancements are expected in the summer of 2009.*

IRP ACTION PLAN LINKAGE TO BUSINESS PLANNING

The IRP is not only a regulatory requirement, but is also a primary tool for PacifiCorp's business planning. As indicated in Chapter 2, the Company has made a concerted effort to further align these two planning processes during this IRP cycle. The business planning process addresses the impacts of resources on the Company's financial health, electricity rates, and the prospects for successful recovery of shareholder investments. Considerations such as resource affordability and financeability thus serve as checks to make sure that the IRP's long-term planning perspective comports with prudent utility business practices under today's commercial and regulatory environments.

For IRP and business planning alignment purposes, major resource differences between the 2008 preferred portfolio and the 2009 business plan approved in December 2008 were analyzed by PacifiCorp Energy's finance department for rate and financial impacts. This analysis also supported credit rating agency review of the business plan. The major resource changes included deferral of the CCCT to 2014 from 2012, deferral of the IC Aero SCCT to 2016 from 2013, and a modified wind acquisition schedule. (The preferred portfolio includes an additional 450 MW from 2009 through 2018.)

RESOURCE PROCUREMENT STRATEGY

To acquire resources outlined in the 2008 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, the Company will use its IRP models to support resource evaluation as part of the procurement process, with updated assumptions including load forecasts, commodity prices, and regulatory requirement information available at time that the resource evaluations occur. This will ensure that the resource evaluations account for a long-term system benefit view in alignment with the IRP portfolio analysis framework as directed by state procurement regulations, and with business planning goals in mind.

The sections below profile the general procurement approaches for the key resource categories covered in the action plan: renewables, demand-side management, thermal plants, distributed generation, and market purchases.

Renewable Resources

The renewables 2008R-1 shelf RFP is representative of the mechanism under which the Company will issue subsequent RFPs to meet most of the renewable resource acquisition goals over the ten-year business planning horizon. The 2008R-1 shelf RFP, to be re-issued on a periodic basis, will allow the Company to react effectively to power supply market developments and changes in the status of RPS requirements, the production tax credit, other financial incentives, and CO_2 legislation. The Company will seek both cost-effective conventional and emerging renewable technologies through the RFP process, including those coupled with energy storage. Qualifying Facilities under the Public Utilities Regulatory Policy Act (PURPA), at least 10 MW in size, are also treated as eligible resources under this particular RFP program.

The Company will also pursue renewable resources through means other than the shelf RFP in recognition that strong competition for renewable projects, and the dynamic nature of renewable construction and equipment markets, will require the Company to respond quickly and efficiently as resource opportunities arise. Other procurement strategies that PacifiCorp will pursue in parallel include bilateral negotiations, PURPA contracting, and self-development.

In addition to supply-side resource acquisition, the Company will add transmission infrastructure and flexible generating resources to support and integrate wind generation. PacifiCorp will also work to improve its understanding of how to integrate large amounts of wind into its portfolio in a reliable and cost-effective manner. Areas of focus include wind forecasting, scheduling practices, curtailment tools, and regional coordination activities.

Demand-side Management

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results (such as the Cool Keeper program). In other cases, PacifiCorp manages the program and contracts out specific tasks (such as the Energy FinAnswer program). A third method is to operate the program completely in-house as was done with the Idaho Irrigation Load Control program. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness. With some RFP's, PacifiCorp developed a specific program design, and put that design out to competitive bid. In other cases, as with the currently active 2008 DSM RFP issued in November 2008, PacifiCorp opened up bidding to many types of Class 1, 2, and 3 programs and design options.

To support the DSM procurement program, the IRP models are used for resource valuation purposes to gauge the cost-effectiveness of programs identified for procurement shortlists. In the case of the 2008 DSM RFP, system benefit valuation estimates will be provided for both Class 1 and 2 programs. For Class 2 programs, PacifiCorp will perform a "no cost" load shape decrement analysis to derive program values, similar to what was done for the 2007 IRP. (Although the supply curve modeling approach used for Class 1 and Class 2 DSM programs can provide a gross-level indication of program value, an avoided-cost type of study is necessary to pinpoint precise values suitable for cost-effectiveness assessment.)

Thermal Plants and Power Purchases

Prior to the issuance of any supply-side RFP, PacifiCorp will determine whether the RFP should be "all-source" or if the RFP will have limitations as to the amount, proposal structure(s), fuel type, or other resource attributes. The Company has lately turned to all-source RFPs in support of IRP fuel-type and technology diversity goals. For example, the 2008 all-source RFP does not specify fuel type requirements, and seeks a range of resources including renewables (greater than 10 MW), power purchase agreements, load curtailment, and QFs.

Company benchmark resources will also be determined prior to an RFP being issued and may consist of a self-build option or ownership transfer arrangement. As with other resource categories, the IRP models will be used for bid evaluation, and will reflect the latest market prices, load forecasts, regulatory policies, and other updated information as appropriate.

Distributed Generation

Distributed generation, such as CHP and distributed standby generators, were found to be cost-effective resources in the context of IRP portfolio modeling. PacifiCorp's procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative, but that is also consistent with PacifiCorp's then-current and applicable tariff filings (QF tariffs for example). As noted in the action plan, QFs of 10 MW or greater are considered eligible resources in the Company's currently active renewables RFP (2008R-1) and the 2008 All Source RFP, which was suspended in February 2009, but is expected to be reactivated later in 2009.

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed generation resources. The Company will also continue to improve representation of distributed generation resource in the IRP models.

ASSESSMENT OF OWNING ASSETS VERSUS PURCHASING POWER

As the Company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the Company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, the Company can hedge itself from the uncertainty of relying on purchasing power from others. On the negative side, owning a facility subjects the Company and customers to the risk that the cost of ownership and operation exceeds expectations, the cost of poor performance or early termination, fuel price risk, and the liability of reclamation at the end of the facility's life.

Purchasing power from another party can help mitigate the risk of cost overruns during construction and operation of the plant, can mitigate some cost and performance risks, and can avoid any liabilities associated with closure of the plant. Short-term purchased power contracts could allow the Company to defer a long term resource acquisition. On the negative side, a long-term purchase power contract relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. For example, a purchase power contract could terminate prior to the end of the term, requiring the Company to replace the output of the contract at then current market prices. In addition, the Company and customers do not receive any of the savings that result from management of the asset, nor do they receive any of the value that arise from the plant after the contract has expired. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation can affect the Company's credit ratios and credit rating.

ACQUISITION PATH ANALYSIS

The acquisition path analysis conducted for the 2008 IRP focuses on four risk areas: regulatory events, load growth, natural gas prices, and procurement delays. The sections below present contingency resource strategies for the Company to consider given significant changes in resource planning conditions tied to these four risk areas. The decision mechanism for pursuing resource strategies is the outcome of the business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions.

Regulatory Events

Table 9.3 outlines a set of resource acquisition strategies tied to regulatory "trigger" events that have been analyzed for the 2008 IRP via input assumption scenarios developed for portfolio analysis. These trigger events include (1) a fairly stringent federal RPS is enacted, (2) the federal renewable production tax credit expires or is phased out in the next 10 years, and (3) federal CO_2 regulation is enacted that results in CO_2 cost above and below PacifiCorp's assumed CO_2 trigger point, which is the CO_2 cost that yields significant changes in the resource mix. Table 9.3 also lists major risks and implementation constraints for each acquisition strategy.

The Public Utility Commission of Oregon IRP guidelines require PacifiCorp to "provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated."[56] For the 2008 IRP, PacifiCorp defined a trigger point of $45/ton (modeled as a CO_2 tax) to demarcate the point at which large changes to future resource acquisitions, and significant changes to existing fossil fuel resource operations, take place. Relative to the 2008 IRP preferred portfolio, defined with the $45/ton CO_2 cost, PacifiCorp defined a trigger point of $70/ton that indicates a reasonable point at which further significant changes to future resource acquisition, as well as major changes to existing fossil fuel resource operations, take place. The Company developed numerous portfolios based on these CO_2 cost trigger points, along with portfolios defined with even higher costs: a $100 CO_2 tax, and a $45 CO_2 tax with real escalation that reaches over $160 by 2028. (Chapter 8 provides expected cost and risk performance results as required by the Oregon IRP guidelines.) PacifiCorp also developed portfolios with no CO_2 tax for estimation of the portfolio cost of CO_2 regulations.

The likelihood that CO_2 prices would reach or exceed $70/ton depends on the confluence of both federal and state policies that have yet to be determined regarding overall strategic goals, program design, and economic sector/industry responsibilities for helping to attain long-term CO_2 reduction objectives. Specifically, governments will need to determine if policies are needed to severely restrict the use of existing fossil fuel resources, and not just discourage new coal plants from being built. Until that policy question is answered, PacifiCorp has no basis to predict whether CO_2 costs will exceed any particular level.

Even when this policy question is answered, there are many uncertainties that complicate the task of predicting how high CO_2 prices will go at this time. For example, assuming that the U.S. adopts a cap-and-trade system like the Waxman-Markey proposal, such open issues as the trajectory of annual CO_2 caps, free allowance and offset policies, state/federal interjurisdictional coor-

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[56] Public Utility Commission of Oregon, Order No. 08-339, "Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process", Guideline 8d, June 30, 2008.

dination, safety valve provisions, linkages to potential federal RPS requirements, and many other factors, will ultimately determine if CO_2 costs exceed $70/ton. Adding to the uncertainty are the following factors:

- The perceived affordability of aggressive CO_2 reduction policies in today's economic environment, which could result in a "take it slow" regulatory track
- The pace of technology advancements
- Public policies towards clean coal, advanced nuclear, and other emerging technologies that are currently controversial
- Commitments to reaching international climate change mitigation goals

Load Growth and Gas Prices

Figure 9.1 shows different resource acquisition paths based on combinations of relative decreases and increases in load growth and gas price projections given the 2008 IRP preferred portfolio input assumptions as the starting point. The acquisition paths shown are necessarily high-level, reflecting resource types rather than quantities and timing. The figure also highlights the connection with CO_2 regulations, the uncertainty of which greatly complicates any type of contingency resource planning involving other planning variables.

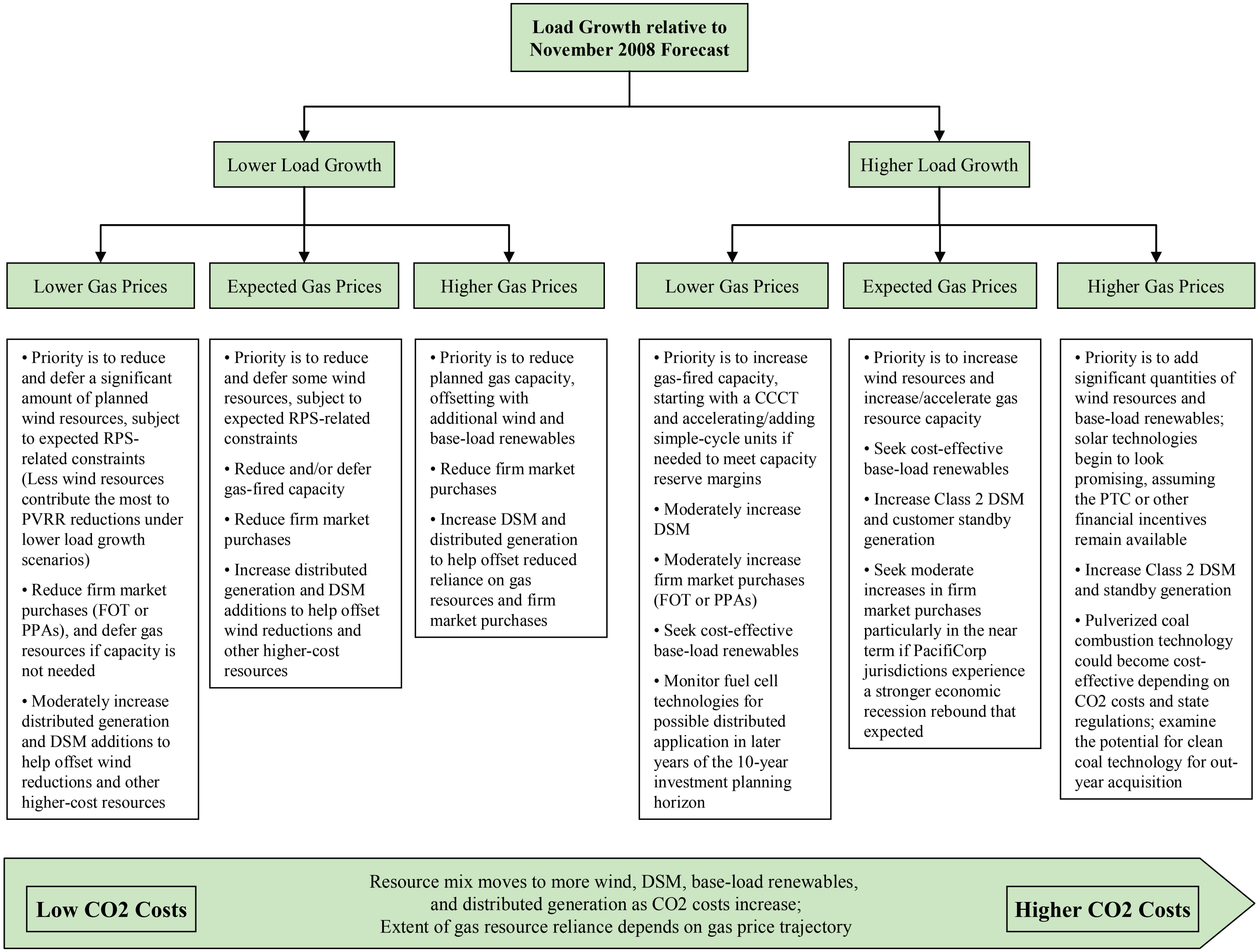
Table 9.3 – Resource Acquisition Paths Triggered by Major Regulatory Actions

Trigger Event	Planning Scenario(s)	Resource Acquisition Strategy	Risks and Constraints
Federal Renewable Portfolio Standard enacted	• A federal RPS is instituted requiring 15% of load to be met with qualifying renewables by 2020, 20% by 2020, and 25% by 2025.	• Cumulative wind capacity totals of 1,600 MW and 3,500 MW are needed by 2020 and 2025, respectively, based on the portfolio developed for the high RPS requirement scenario (case 44). • Spread incremental renewables acquisition according to an annual schedule for procurement flexibility, accelerating as necessary to account for near-term RPS requirements and to take advantage of cost-effective site availability, transmission access, and government financial incentives. • Aggressively diversify the renewables portfolio with other technologies (geothermal, solar, and biomass) as dictated by market conditions and the availability of suitable cost-effective projects. • Continue to issue renewable RFPs under PacifiCorp's shelf RFP program, and step up consideration of unsolicited proposals and multi-participant projects as opportunities arise. • Step up acquisition of demand-side management programs and distributed renewables generation to mitigate cost and procurement risks of utility-scale supply-side projects. • Adjust transmission construction plans and increase regional transmission coordination efforts to facilitate project development activity.	• Ratepayer affordability and Company financial impacts associated with a large and protracted renewables acquisition program. • Demand/supply imbalance for wind turbines and labor results in project delays and higher construction costs. • Local environmental and land use concerns/restrictions begin to adversely impact renewable project plans by increasing resource costs and forcing construction delays. • Transmission construction delays. • Increased exposure to wind integration issues and increased need for flexible resources. • Compliance burden and costs associated with multi-jurisdictional RPS requirements.
Federal renewable production tax credit expiration or cutback	• The federal renewables PTC expires within the 2013-2018 period for wind, or less likely, all renewable resources. • The federal renewables PTC is phased out over a multi-year period.	• Accelerate renewables acquisition to obtain as much as possible before the federal PTC expiration date; renewable additions were not found to be cost-effective without the federal PTC during the 2013-2018 period, given relatively low CO_2 costs.	• Acceptability of associated rate increases due to the accelerated renewables acquisition combined with other generation and transmission resource acquisitions. • Near-term impact on the Company's financial situation. • Regulatory requirements (siting and procurement) that could jeopardize

Trigger Event	Planning Scenario(s)	Resource Acquisition Strategy	Risks and Constraints
			meeting required in-service dates.
CO_2 emission compliance: low to medium cost impact	• A federal cap-and-trade program or CO_2 tax is implemented with an effective production cost impact of up to $70/ton.	• The preferred portfolio is considered a reasonable planning starting point for an uncertain CO_2 cost up to $70/ton. • The 2008 IRP preferred portfolio would be modified as an outcome of business plan/IRP portfolio modeling to reflect updated assessments of CO_2 regulations (start and trajectory of CO_2 costs), other energy policies affecting renewable energy acquisition and economics, and forward gas prices. (Natural gas prices affect the quantity of wind included in the resource portfolio. For example, comparing the preferred portfolio and the portfolio for case 8B, a 20% increase in gas prices was found to result in a 700 MW increase in wind selected by the capacity expansion model.) • Depending on expected CO_2 costs and gas prices, step up acquisition of demand-side management programs and high-efficiency distributed generation to help minimize the carbon footprint, continue to diversify the resource mix, and take advantage of any CO_2 compliance credits that may be given to these resource types. • Modify the bid evaluation process (which is based on the IRP portfolio modeling framework) to reflect updated CO_2 regulatory expectations.	• Ratepayer affordability and Company financial impacts associated with CO_2 costs that approach the upper end of the cost range ($40 to $70/ton). • Compliance burden and costs associated with multi-jurisdictional CO_2 regulatory requirements.
CO_2 emission compliance: high cost impact	• A federal cap-and-trade program or CO_2 tax is implemented with an effective production cost of $70/ton or greater.	• Acquire at least an additional 2,500 MW of wind and at least 70 MW of geothermal capacity or other base-load renewable resources, with the timing and annual amounts tied to the start of CO_2 regulations and trajectory of CO_2 costs. These minimum targets are suggested by the portfolio generated from case 17B, optimized using a $70/ton CO_2 cost. • Consider emission offset possibilities to ame-	• Customer affordability and Company financial impacts associated with necessary resource acquisitions (including those needed to potentially replace less efficient fossil fuel plants). • Compliance safety value or emergency off-ramp provisions kick in due to high compliance costs.

Trigger Event	Planning Scenario(s)	Resource Acquisition Strategy	Risks and Constraints
		liorate resource acquisition and cost risks. • Step up acquisition of higher-cost demand-side management programs and high-efficiency distributed generation to further minimize the carbon footprint. • Consider advanced high-efficiency gas generation technologies, evaluating the trade-off between greater efficiency and higher capital costs and project risks. • Aggressively pursue efficiency improvements for PacifiCorp's existing fossil fuel and hydropower plants. • For long-term resource needs and to potentially replace existing fossil fuel plants, continue to reevaluate clean coal technologies, advanced nuclear, and emerging renewable and energy storage technologies. • Modify the bid evaluation process to reflect updated CO_2 regulatory expectations.	• Demand/supply imbalance for wind turbines and labor results in project delays and higher construction costs. • Local environmental and land use concerns/restrictions begin to adversely impact renewable project plans by increasing resource costs and forcing construction delays. • Transmission construction delays. • Increased exposure to wind integration issues and increased need for flexible resources. • Compliance burden and costs associated with multi-jurisdictional requirements or poorly designed implementation.

Figure 9.1 – Resource Acquisition Paths Tied to Load Growth and Natural Gas Prices



Procurement Delays

The main procurement risk is an inability to procure resources in the required time frame to meet the need. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2008 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or a material change in the market for fuels, materials, electricity, or environmental or other electric utility regulations, may change the Company's entire resource procurement strategy.

Possible paths PacifiCorp could take if there was either a delay in the on-line date of a resource or, if it was no longer feasible or desirable to acquire a given resource, include the following:

- Consider alternative bids if they haven't been released under a current RFP
- Issue an emergency RFP for a specific resource
- Move up the delivery date of a potential resource by negotiating with the supplier/developer
- Rely on near-term purchased power and transmission until a longer-term alternative is identified, acquired through PacifiCorp's mini-RFPs or sole source procurement
- Install temporary generators to address some or all of the capacity needs
- Temporarily drop below the 12 percent planning reserve margin
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts

MANAGING CARBON RISK FOR EXISTING PLANTS

Carbon dioxide reduction regulations at the federal and state levels would prompt the Company to continue to look for measures to lower CO_2 emissions of existing thermal plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures would be cost-effective and practical from operational and regulatory perspectives. For a cap-and-trade system, examples of factors include the allocation of free allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. To lower the emission levels for existing thermal plants, options include changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and. adoption of new technologies such as CO_2 capture with sequestration when commercially proven. Indirectly, plant carbon risk can be addressed by acquiring offsets in the form of renewable generation and energy efficiency programs. Under an aggressive CO_2 regulatory environment, early coal plant retirement becomes a tenable option. Such coal plant retirement decisions would also depend on market conditions and technological advancements that would enable cost-effective base-load power replacement or retrofit opportunities.

High CO_2 costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, but as a general rule, coal units will continue to use the existing coal technology until it is more cost-effective to replace the unit in total. A major issue is whether new technologies will be available that can be exchanged for existing coal economically.

Fuel switching and dual-fueling provide some limited opportunities to address emissions, but will require both capital investment and an understanding of the trade-offs in operating costs and risks. While these options would provide the Company a means to lower its emission profile, such options would be extremely expensive to implement unless there is a high carbon emission penalty to justify them.

USE OF PHYSICAL AND FINANCIAL HEDGING FOR ELECTRICITY PRICE RISK

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

The Company also proposes to continue to hedge the physical delivery risk inherently carried due to the volume mismatch between physical resources and physical obligations by purchasing or selling physical products in the forward through real-time markets. The purpose of purchases is to ensure adequate resources to maintain reliable delivery to the Company's obligations such as retail load. The purpose of sales is to ensure the Company's ability to economically generate and deliver electricity to wholesale purchasers.

MANAGING GAS SUPPLY RISK

Adding natural gas generating resources to PacifiCorp's system requires an understanding of the fuel supply risks associated with such resources, and the application of prudent risk management practices to ensure the availability of sufficient physical supplies and limit price volatility exposure. The risks discussed below include price, availability, and deliverability.

Price Risk

PacifiCorp manages price risk through a documented hedging strategy. This strategy involves fully hedging price risk in the nearest 12-month period and hedging less of the exposure each year beyond that through year four. Near-term prices are fully hedged to add price certainty to near term planning horizons, budgets, and rate case filings. Further out, where plans and budgets are less certain, PacifiCorp considers its most recent ten-year business plan, current market fundamentals, credit risk, collateral funding, and regulatory risk in making hedging decisions. PacifiCorp balances the benefit of hedging that plan's price assumptions with prudent risk management for its ratepayers and shareholders. PacifiCorp hedges price risk through the use of financial swap transactions and/or physical transactions. These transactions are executed with various counterparties that meet PacifiCorp's credit and contractual requirements.

Availability Risk

Availability risk refers to the risk associated with having natural gas supply in the vicinity of contemplated generating assets. PacifiCorp purchases physical supply on a forward basis achieving contractual commitments for supply. The Company also relies on its ability to purchase physical supplies in the future to meet requirements. This second approach subjects PacifiCorp to price risk resulting from swings in supply-demand balances, as well as the risk that natural gas production in a producing region ceases regardless of price. It is reasonable that a region-wide cease in production, given reserve estimates, could only be brought about by extreme and unforeseen events such as natural disaster or regulatory moratoriums on the production or consumption of natural gas—events that long-term supply commitments would not counteract. Index prices are designed to reflect the prevailing cost of supply at various delivery locations. As described above, PacifiCorp hedges its exposure to changes in those index prices, thereby allowing for procurement of supply at floating index prices or waiting to acquire supply when requirements estimates are more accurate and the premiums for longer-term commitments are no longer demanded by suppliers.

Deliverability Risk

Deliverability risk refers to the risk associated with transporting natural gas supply from supply locations to generating facilities. The 2008 IRP accounts for the cost of natural gas transportation service required to fuel gas plants, and uses existing tariff pipeline-defined transportation capacity and transportation costs in evaluating the need, timing, and location of new natural gas-fired generating plants. More specifically, the 2008 IRP uses existing maximum tariff rates for demand charges, volumetric costs, and reimbursement of fuel and lost/unaccounted natural gas. These tariff rates are developed through cost of service filings with appropriate regulators—the FERC for interstate pipelines and relevant state regulators for intrastate pipelines. By definition, rates are developed based on cost of service of existing operations, without consideration for maintenance and operations of future expansions. The result of this is that the 2008 IRP assumes that the economics of a new natural gas fired generator reflect the current cost of service for existing natural gas transportation facilities; whereas, the cost of any new natural gas transportation capacity is dependent on the volumetric size of the new capacity, and prevailing costs of construction, maintenance, and operations (e.g. steel, labor, financing).

Also, the 2008 IRP accounts for the availability of natural gas transportation service required to fuel new electricity generating facilities. In selecting a gas-fired resource, the implicit assumption is made that natural gas transportation infrastructure exists or will be built. This is a reasonable assumption if one further assumes that the construction of new pipeline facilities is a function of cost, which is addressed above.

PacifiCorp manages this transportation cost through two transaction types: transportation service agreements and delivered natural gas purchases:

- PacifiCorp enters into transportation service agreements that offer PacifiCorp the right to ship natural gas from prolific production basins or liquidly traded “hubs” to generating assets. Natural gas hubs exist where a large volume of production is gathered and delivered into a large interstate pipeline or where large pipelines intersect. These hubs lead to liquidly traded markets as the movement of gas from one transporting pipeline to another lead to a large number of willing buyers and sellers.

- PacifiCorp purchases natural gas delivered to generating plants and/or hubs. This approach pushes the deliverability risk to the supplier by contractually committing it to making necessary supply and/or transportation arrangements.

PacifiCorp is confident that the risks associated with fueling current and prospective natural gas fueled generation can be effectively managed. Risk management involves ongoing monitoring of the factors that affect price, availability, and deliverability. While prudence warrants the monitoring of many factors, some issues that PacifiCorp needs to pay particular attention to, given today's market, include the following:

- Potential counterparties need to be continually monitored for their creditworthiness and long-term viability, especially given the current economic downturn.
- Environmental concerns could impact natural gas prices, particularly given the prospects of a CO_2 cap-and-trade or tax program. PacifiCorp continues to monitor the regulatory environment and its potential impact on natural gas pricing.
- As production grows in the Rocky Mountains, so does the transportation infrastructure. PacifiCorp continues to monitor this activity for risks and opportunities that new pipeline infrastructure may yield.

TREATMENT OF CUSTOMER AND INVESTOR RISKS

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

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the 2008 IRP. Capital expenditures continue to increase, driven by the need for infrastructure investment to support load growth and maintain reliable electricity supplies, and the effects of cost inflation. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risk of this type facing PacifiCorp continues to be government actions related to CO_2 emissions. This scenario risk relates to the uncertainty in predicting the scope, timing, and cost impact of CO_2 emission compliance rules. Chapter 3 frames this issue in terms of the impacts of CO_2 policy and cost uncertainty on natural gas and wholesale electricity prices, and consequent dramatic cost impacts to consumers.

To address this risk, the Company decided in 2007 that acquiring a coal plant was not a viable resource option until regulatory clarity concerning CO_2 costs and technology/fuel policies is obtained. While coal plants are allowed as eligible resources for competitive procurements that solicit base-load resources, PacifiCorp evaluates all bid resources using a range of CO_2 prices consistent with the scenario analysis methodology adopted for the Company's IRP portfolio evaluation process. Further, coal resources must comply with applicable existing state CO_2 compliance regulations. The risk of potential future CO_2 costs is therefore fully accounted for in resource planning and procurement decision-making. The Company's efforts to acquire wind and DSM resources also serve as effective CO_2 risk mitigation measures.

10. TRANSMISSION EXPANSION ACTION PLAN

INTRODUCTION

Since the original announcement of Energy Gateway in May 2007 and as discussed further in Chapter 4, PacifiCorp has emphasized that significant infrastructure of new transmission capacity is needed to adequately serve PacifiCorp's existing and future loads. The Company's position has not changed in this regard and still requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South) of new transmission capacity to adequately serve its customers load and growth needs for the long-term.

PacifiCorp also recognized in its original announcement the need and benefits of potentially "upsizing" the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors, potential to reduce environmental impacts, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity.

PacifiCorp still believes there are short-term and long-term benefits for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp is proceeding with efforts regarding planning, rating, and permitting requirements for the Energy Gateway Program that facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need and construction timing.

PacifiCorp is moving forward with the expansion plan that will construct transmission lines and substations required to provide 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads.

In addition, several main grid reinforcement projects that are complementary to the Energy Gateway program are scheduled for completion over the next several years. They are described after the Energy Gateway segments.

High-level descriptions of the Energy Gateway segments and Company planning activities are outlined below. In-service dates are based on optimal timing of transmission needs and best efforts to complete construction. The dates reflect the most recent Gateway planning assessment, which occurred after the completion of IRP modeling described in the preceding chapters. Gateway plan modifications will be incorporated in PacifiCorp's 2010 business plan and the 2008 IRP update. In-service dates are subject to timing shifts based on permitting, environmental approvals, and construction schedules.

GATEWAY SEGMENT ACTION PLANS

Walla Walla to McNary – Segment A

Originally planned as a single circuit 230 kV transmission line approximately 56 miles in length between Wall Walla, Washington and Umatilla, Oregon that connects existing substations at Walla Walla, Wallula, and McNary. The initial target completion date was 2010; however, additional information became available in early 2009 that prompted the decision to defer moving forward with the current project scope in 2009.

PacifiCorp acquired the Chehalis generation plant in late 2008 and on February 13, 2009 redirected 470 MW of transmission rights to the Mid Columbia area. Existing transmission rights between Yakima and Walla Walla allow a portion of the Chehalis resources to cover any Walla Walla short resource position. This minimizes any net power costs benefits from the prior economics that showed Hermiston generation located in Oregon displacing Mid-Columbia purchases and serving Yakima and Walla Walla loads during short supply periods.

Over the next six to twelve months, PacifiCorp is actively participating in transmission plans and system rating processes impacting the Northwest, and these plans are expected to mature and possibly influence PacifiCorp's Westside Plan. At that time, the Company will determine any additional transmission needed in the Walla Walla / McNary area. PacifiCorp will continue to evaluate the project and incorporate the analysis with regional transmission needs.

Populus to Terminal – Segment B

A double circuit 345 kV line that will run approximately 135 miles from a new substation (Populus) near Downey, Idaho to the existing Terminal Substation near Salt Lake International Airport west of Salt Lake City, Utah. When completed in 2010, this segment will improve reliability along a critical transmission corridor (Path C) and provide additional transfer capability of energy resources both south bound and north bound. It will also provide a vital link for Energy Gateway path ratings.

Mona to Limber to Oquirrh – Segment C

A single circuit 500 kV line that will run approximately 65 miles between the existing Mona Substation in central Utah to a future substation called Limber in the Tooele Valley, west of Salt Lake City, Utah. It will also include a double circuit 345 kV line that will run approximately 21 miles between the future Limber Substation to an existing substation called Oquirrh in the Salt Lake valley. When completed in 2012, it provides a critical northbound path for additional resource whether internally generated or purchased through market transactions. It will also provide a vital link for reliability and Energy Gateway path ratings.

Oquirrh to Terminal

A double circuit 345 kV line that will run approximately 14 miles between the Oquirrh Substation to an existing Terminal Substation near Salt Lake International Airport west of Salt Lake City, Utah. When completed in 2012, it will add operational flexibility to the bulk electrical system, improved reliability and will provide a vital link for Energy Gateway path ratings.

Windstar to Aeolus to Bridger to Populus – Segment D

Part of Energy Gateway West, it is comprised of two single circuit 230 kV lines that will run approximately 82 and 72 miles respectively between the recently constructed Windstar Substation in eastern Wyoming to a new substation called Aeolus near Medicine Bow, Wyoming. It will continue as a 500 kV single circuit line that will run approximately 141 miles from Aeolus Substation to a new annex substation near the existing Bridger Substation near Jim Bridger Power Plant in western Wyoming.

The last section will connect the new annex substation located near Bridger Substation to the Populus Substation that is being constructed as part of the Populus to Terminal segment. When completed in 2014, the entire segment will move wind or other resources from eastern Wyoming to a critical hub (Populus) located near Downey, Idaho. The Populus Substation is the intersection substation for Gateway West and Gateway Central.

Populus to Hemingway – Segment E

Two single circuit 500 kV lines that will run approximately 135 and 149 miles respectively between the Populus Substation and the existing Midpoint Substation. One of the lines will also connect the existing Borah Substation between Populus and Midpoint. The segment will continue as a single circuit 500 kV line for approximately 126 miles from Midpoint Substation to a new Hemingway Substation located south of Boise on the south side of the Snake River between the towns of Melba and Murphy. When completed in 2016 the segment will connect resources located in eastern Wyoming and Gateway Central to load centers further west. It will also allow the Company to maintain reliable electric service in the Western Interconnection.

Aeolus to Mona – Segment F

A single-circuit 500 kV line that runs approximately 395 miles between the Aeolus Substation (constructed as part of Gateway West) and the Mona Substation (expanded as part of Gateway Central). When completed in 2017 the segment will connect Gateway West and Gateway Central providing operational flexibility for the bulk electric network, reliability and supports path ratings for each segment.

Sigurd to Red Butte – Segment G

A single circuit 345 kV line that runs approximately 160 miles connecting the existing Sigurd Substation located in central Utah to another existing substation called Red Butte Substation located in southwest Utah. When completed in 2014, it provides a critical path to meet load obligations, increase export capability and to maintain transmission capacity on TOT2C for contracted point to point service. Specific routing alternatives are currently being considered in the permitting and ratings processes.

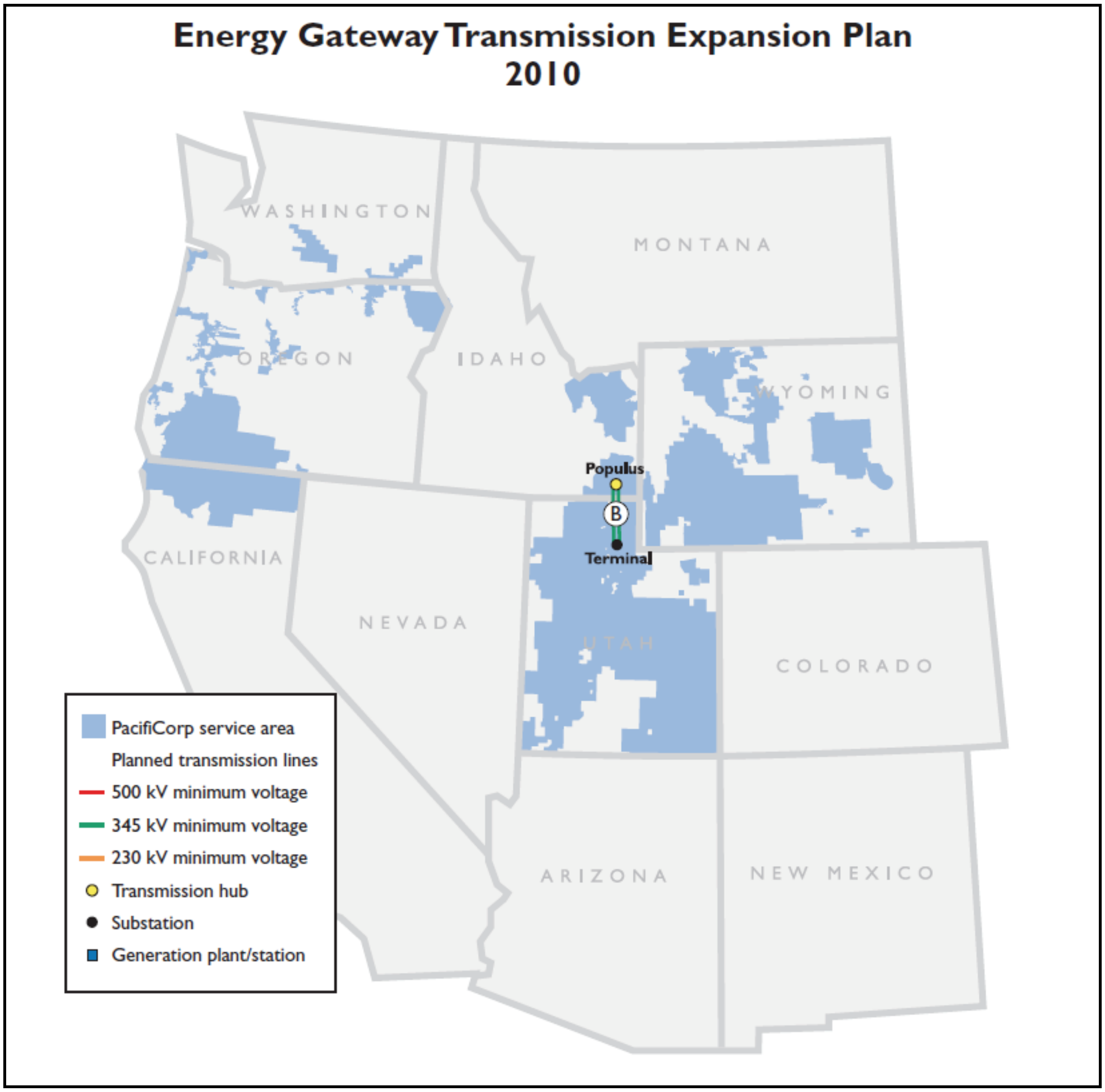
Segment G originally included a single circuit 500 kV line from Red Butte Substation in Utah to Crystal Substation in Nevada. The transmission line is being deferred for further review due to the fact that existing customer forecasted needs are anticipated to be met without its construction. Studies show bi-directional flows to markets are met by installing upgrades at Harry Allen Substation in Nevada and other system reinforcements in 2014. Although the segment is not needed at this time for the 1,500 MW Gateway South expansion plan, the line segment and related substation upgrades will be required for Energy Gateway South to obtain the next incremental rating of 3,000 MW total.

Construction of the planned transmission segments by estimated in-service dates and additional megawatt capacity are shown in the following sequence of maps. Delivery of the segments by the calendar years shown are particularly critical for Gateway West from Windstar to Populus, Gateway Central from Mona to Terminal, and Gateway South from Sigurd to Red Butte, due to the IRP preferred portfolio reliance on available transmission.

Maintaining sufficient transmission capacity for southwest Utah loads and maintaining contracted point-to-point transmission service prior to the Sigurd to Red Butte - Segment G addition in 2014 will require several substation upgrades. The Sigurd to Red Butte project is being considered with other alternatives to meet the requirements in SW Utah. In 2010, PacifiCorp is planning to install additional station equipment at Harry Allen Substation, Pinto Substation and Three Peaks Substation and in 2011 additional station equipment is being installed at Red Butte Substation.

Additional main grid reinforcement projects also includes upgrades to TOT2C path at Harry Allen Substation in Nevada, which will increase bi-directional flows to markets in the Desert Southwest needed in 2014.

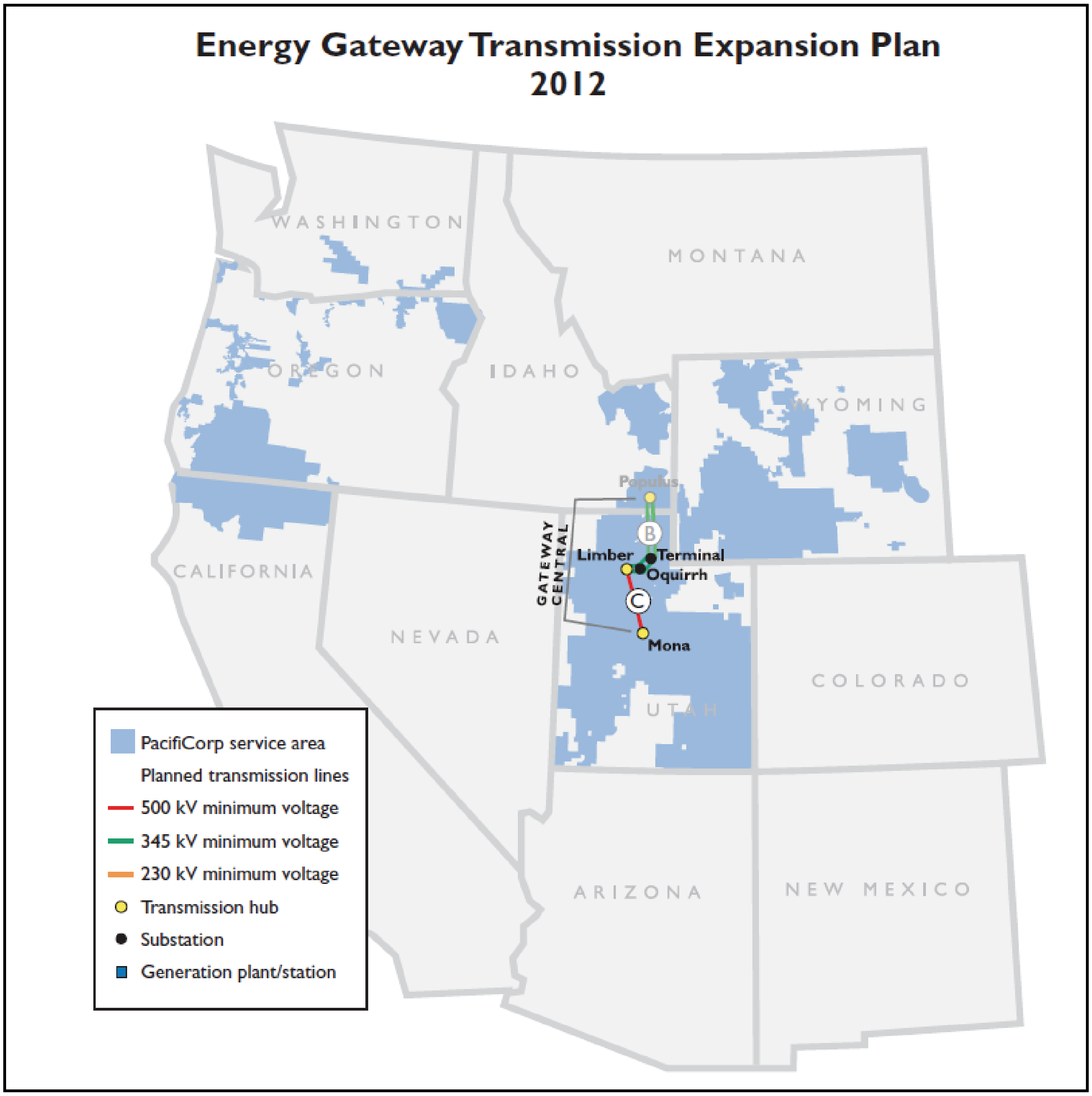
Figure 10.1 – Energy Gateway 2010 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
B	Populus - Terminal	345 kV double circuit	700 MW	1400 MW

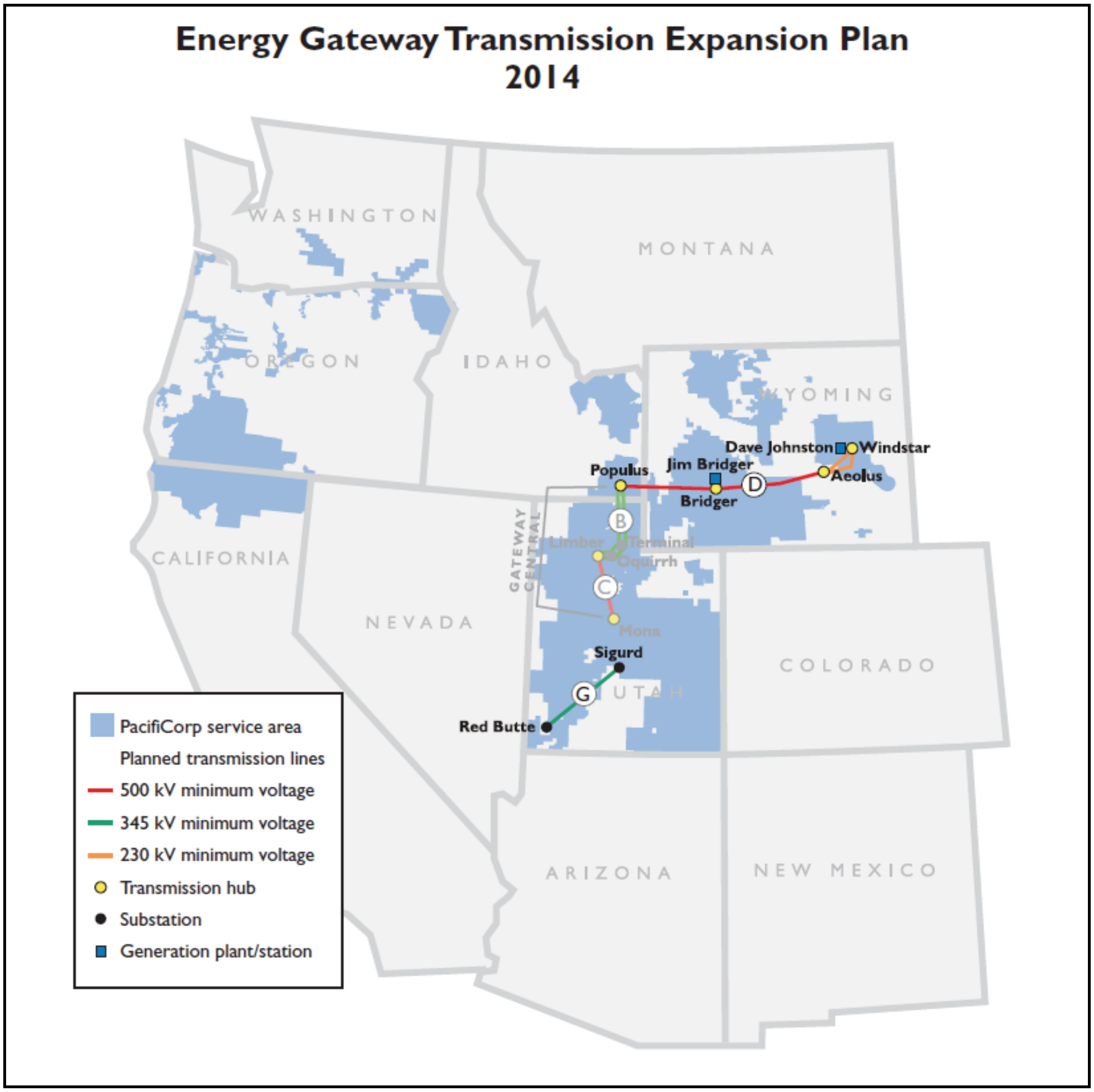
Figure 10.2 – Energy Gateway 2012 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
C	Mona – Limber Limber – Oquirrh	500 kV single circuit/ 345 kV double circuit	700 MW	1500 MW
Other	Oquirrh – Terminal	345 kV double circuit	700 MW	1500 MW

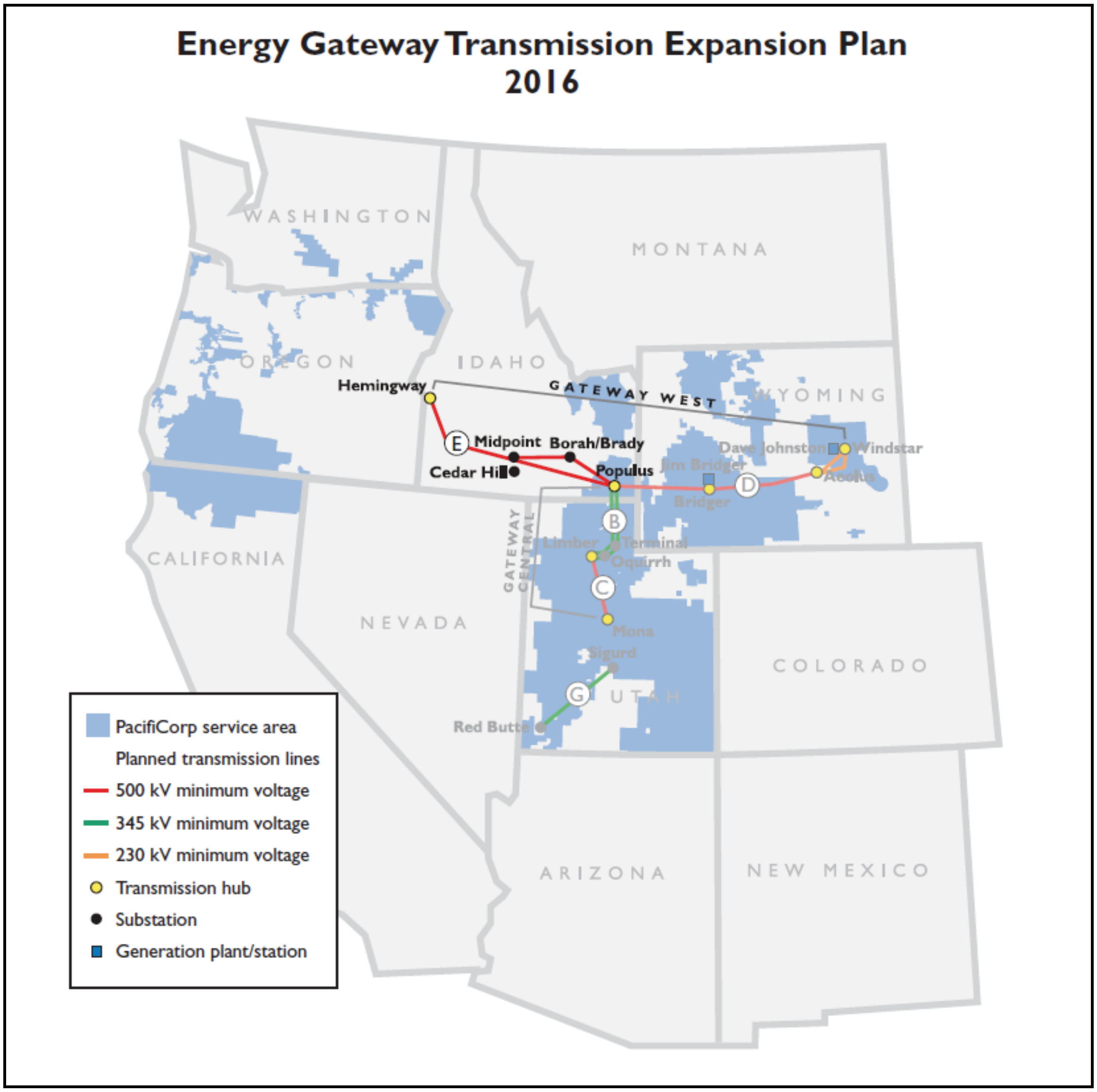
Figure 10.3 – Energy Gateway 2014 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
D	Windstar – Aeolus	2-230 kV single circuits	700 MW	700 MW
	Aeolus –Bridger	500 kV single circuit	700 MW	1500 MW
	Bridger - Populus	500 kV single circuit	700 MW	1500 MW
G	Sigurd – Red Butte	345 kV single circuit	600 MW	600 MW
Various	Various upgrades at Harry Allen to increase capacity to the Desert Southwest	TOT2C Path	600 MW	600 MW

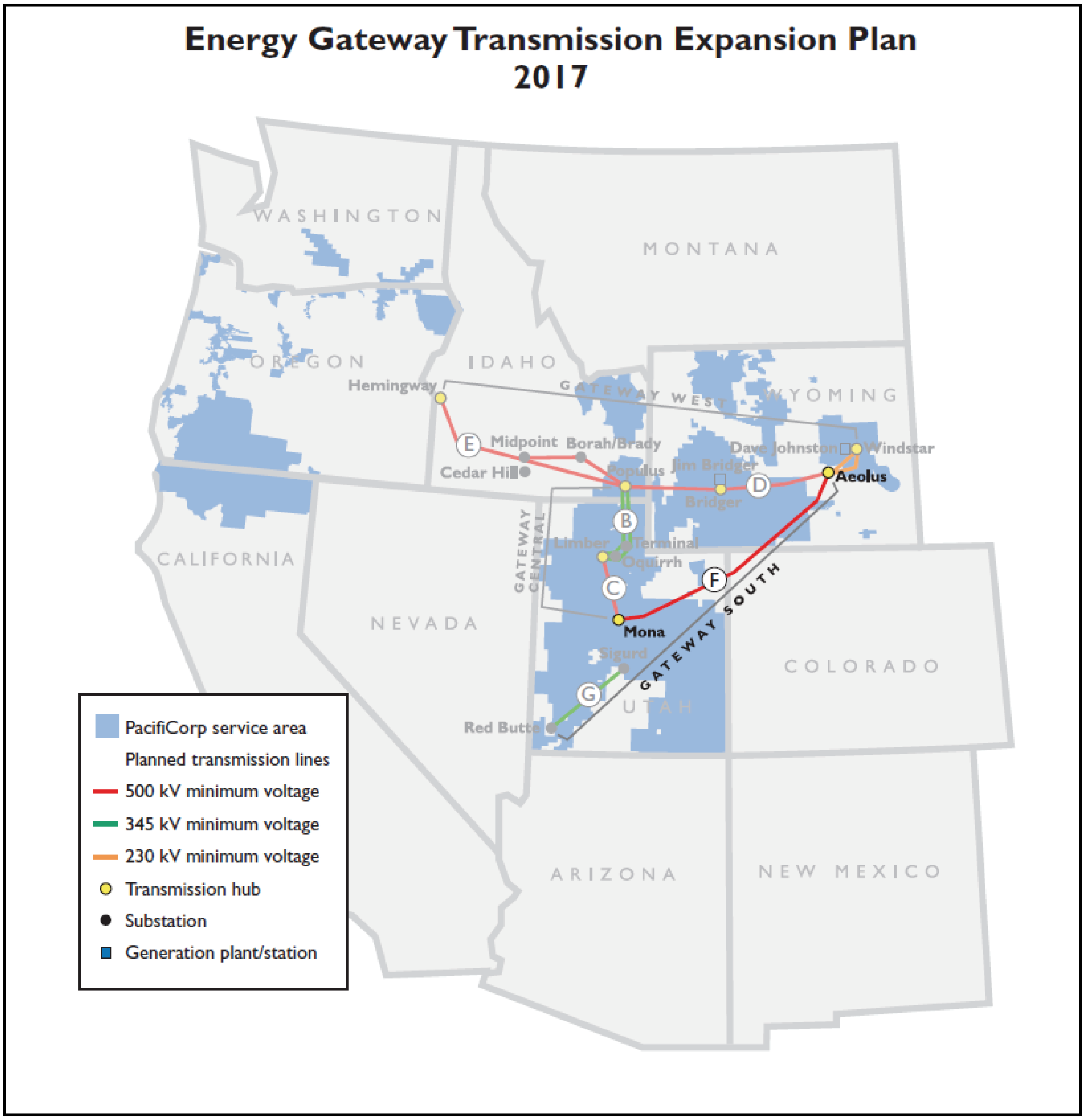
Figure 10.4 – Energy Gateway 2016 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
E	Populus – Borah – Midpoint	500 kV single circuit	700 MW	1500 MW
E	Populus – Midpoint – Hemingway	500 kV single circuit	700 MW	1500 MW

Figure 10.5 – Energy Gateway 2017 Additions



Note: This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
F	Aeolus – Mona	500 kV single circuit	1500 MW	1500 MW

Westside Plan / Red Butte – Crystal

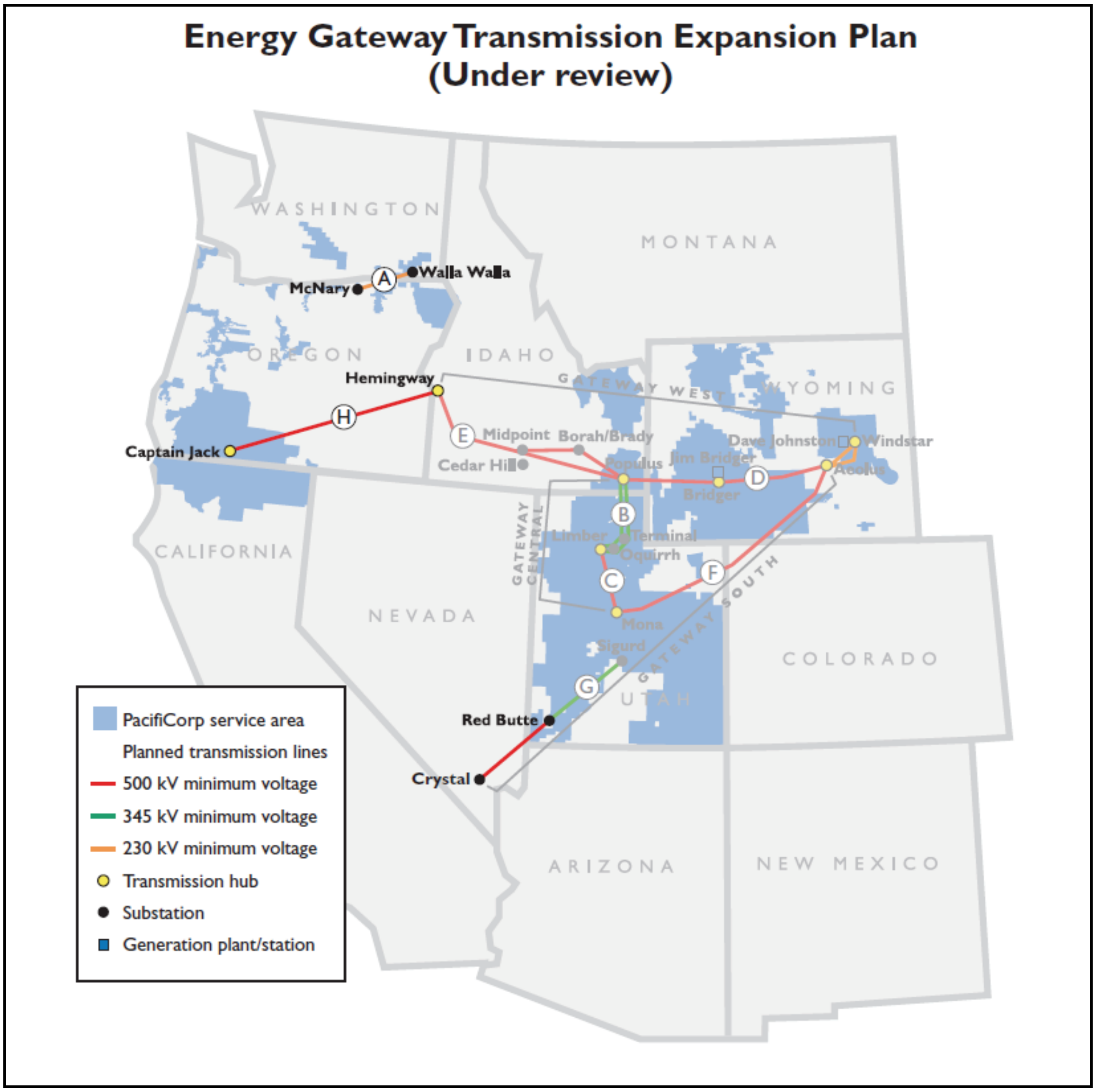
The west side of PacifiCorp's system (Washington, Oregon and California) is well integrated with Avista Energy, Bonneville Power Administration, Portland General Electric, and, to a lesser degree, interconnections to the California Independent System Operator. Additionally, several regional projects have been proposed to interconnect in the northwest (California to Canada Transmission, Boardman to Hemingway, Southern Crossing, West of McNary, I-5 reinforcement, Devils Gap, Northern Lights and others).

PacifiCorp's Walla Walla to McNary single circuit 230 kV line and Hemingway to Captain Jack single circuit 500 kV line will be planned and coordinated with other regional projects to provide the best solution for customers and the region. Ultimate configuration and timing of PacifiCorp's Walla Walla to McNary and Hemingway to Captain Jack projects is an action item resulting from this IRP.

The Red Butte to Crystal single circuit 500 kV line was originally planned for 2012 but was deferred due to other Energy Gateway/system reinforcement projects providing sufficient transmission capacity to meet customer requirements. The line will be reevaluated as future needs are identified.

The map shown below shows the geographic context of the segments described above.

Figure 10.6 – Westside Plan / Red Butte – Crystal



Note: This map generally reflects key expansion segments under review. It does not reflect all the segments that are necessary to for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

Segment	Segment Description	Line	Planned Rating (Initial completion)	Planned Rating (Core completion)
A	Walla Walla – McNary	230 kV single circuit	400 MW	400 MW
G	Red Butte - Crystal	500 kV single circuit	TBD	1500 MW
H	Hemingway – Captain Jack	500 kV single circuit	TBD	1500 MW

Let's turn the answers on.

2008
Integrated Resource Plan
Volume II - Appendices

PACIFICORP
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May 28, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2008 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: Foot 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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APPENDIX A – DETAIL CAPACITY EXPANSION RESULTS

This appendix provides additional System Optimizer results for each of the cases studied during the 2008 IRP. A prior version of this appendix was provided to IRP public participants in December 2008 and later updated. New to this appendix are the additional "B-Series" cases and their respective charts and tables which are at the end of each section of this appendix. The follow bullets layout this appendix;

Reference Information

- Case Definition List
- Resource Name List

Charts and Pivot Summaries

- Portfolio Area Charts
    - "B-Series" Area Charts
- Core Cases – Pivot Summary
    - 2009 to 2013
    - 2014 to 2020
    - 2021 to 2028
- Core Cases – 20-Year Summary by Scenario Variable
    - CO_2 Tax Level
    - Gas Price Curves
    - Load Growth Level
- Core Cases – Resource Type Summary

Detail Portfolio Data

- Portfolio RPS Summary
- Portfolio Summary Tables
- B Series Delta Summary Comparison

Table A.1 – Core Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Core Cases										
1	CO2 tax	$0	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
2	CO2 tax	$0	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
3	CO2 tax	$0	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
4	CO2 tax	$45	Low	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
5	CO2 tax	$45	Low	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
6	CO2 tax	$45	Low	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
7	CO2 tax	$45	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
8	CO2 tax	$45	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
9	CO2 tax	$45	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
10	CO2 tax	$45	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
11	CO2 tax	$45	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
12	CO2 tax	$45	Medium	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
13	CO2 tax	$45	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
14	CO2 tax	$45	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
15	CO2 tax	$45	High	Jun-08	High	Base, if needed	Base	Base	12%	Excluded
16	CO2 tax	$70	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
17	CO2 tax	$70	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
18	CO2 tax	$70	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
19	CO2 tax	$70	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
20	CO2 tax	$70	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
21	CO2 tax	$70	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
22	CO2 tax	$70	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
23	CO2 tax	$100	Medium	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
24	CO2 tax	$100	Medium	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded
25	CO2 tax	$100	Low	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
26	CO2 tax	$100	Medium	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
27	CO2 tax	$100	High	Oct-08	Medium	Base, if needed	Base	Base	12%	Excluded
28	CO2 tax	$100	High	Jun-08	Low	Base, if needed	Base	Base	12%	Excluded
29	CO2 tax	$100	High	Jun-08	Medium	Base, if needed	Base	Base	12%	Excluded

Table A.2 – Sensitivity and Business Plan Reference Case Definitions

Case #	CO2 Compliance Strategy and Costs		Base Gas Cost (Prior to CO2 compliance impact adjustments)		Load Growth	Renewable Portfolio Standard	Clean Baseload Plant Available	Plant Construction Cost	Planning Reserve Margin	Class 3 DSM for Peak Load Reduction
	Compliance Type (CO2 tax, federal cap-and-trade, hard cap)	CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation	Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008	Price Curve Date	**Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point	**High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met	**Base** = 2025 **Early** = 2020 **Late** = 2030	**Base** **High** = Base + 20%		**Excluded** as capacity resource **Included** as capacity resource
Real CO2 Cost Escalation with Changing Load Growth										
30	CO2 tax	$45 (2013) to $163 (2028)	Medium	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
31	CO2 tax	$45 (2013) to $163 (2028)	High	Jun-08	Medium (2009-2020) Low (2021-2028)	Base	Base	Base	12%	Excluded
National CO2 Cap-and-Trade Policy: Lieberman-Warner "Climate Security Act of 2008" (SB 3036, introduced May 20, 2008)										
32	Cap-and-Trade	Market	Medium	Oct-08	Medium	Base	Base	Base	12%	Excluded
High-Cost Outcome										
33	CO2 tax	$100	High	Jun-08	High	Base	Late	High	12%	Excluded
Clean Base-Load Generation Availability										
34	CO2 tax	$45	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
35	CO2 tax	$45	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
36	CO2 tax	$70	Medium	Jun-08	Medium	Base	Early	Base	12%	Excluded
37	CO2 tax	$70	High	Jun-08	Medium	Base	Early	Base	12%	Excluded
High Plant Construction Costs										
38	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	High	12%	Excluded
39	CO2 tax	$45	High	Jun-08	Medium	Base	Base	High	12%	Excluded
Oregon CO2 Reduction Targets (from HB 3543) Applied as System-wide Hard Caps										
40	Hard Cap	N/A	Medium	Jun-08	Medium	Base	Base	Base	12%	Excluded
Alternative Planning Reserve Margin Level (15%)										
41	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
42	CO2 tax	$70	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
43	CO2 tax	$100	Medium	Jun-08	Medium	Base	Base	Base	15%	Excluded
Alternative renewable policy assumptions										
44	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	High	Base	Base	12%	Excluded
45	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Base/PTC expires	Base	Base	12%	Excluded
Business Plan Reference Cases										
46	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Fixed RPS-compliant wind schedule	Base	Base	12%	Excluded
47	Cap-and-Trade	$8 allowance price	Medium	Oct-08	Medium	Optimized RPS-compliant renewables	Base	Base	12%	Excluded
Class 3 DSM For Peak Load Reduction										
48	CO2 tax	$45	Medium	Jun-08	Medium	Base	Base	Base	12%	Included

Table A.3 – Resource Name and Description

Plant	Side	Description
CCS Hunter3	East	IRP Carbon Capture & Sequestration Hunter 3
Coal Plant Turbine Upgrades	East	Coal Plant Turbine Upgrades
UT IGCC CCS	East	IRP Utah Integrated Gasificafication Combine Cycle Carbon Capture & Sequestration
UT Pulverized Coal	East	IRP Utah Pulverized Coal
UT Pulverized Coal CCS	East	IRP Utah Pulverized Coal Carbon Capture & Sequestration
WY IGCC CCS	East	IRP Wyoming Integrated Gasificafication Combine Cycle Carbon Capture & Sequestration
WY Pulverized Coal	East	IRP Wyoming Pulverized Coal
WY Pulverized Coal CCS	East	IRP Wyoming Pulverized Coal Carbon Capture & Sequestration
CCS Bridger1	West	IRP Carbon Capture & Sequestration Bridger 1
CCS Bridger2	West	IRP Carbon Capture & Sequestration Bridger 2
CCCT F 1x1	East / West	Combine Cycle Combustion Turbine F-Machine 1x1 with Duct Firing
CCCT F 2x1	East / West	Combine Cycle Combustion Turbine F-Machine 2x1 with Duct Firing
CCCT G 1x1	East / West	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing
CCCT H 2x1	East / West	Combine Cycle Combustion Turbine H-Machine 2x1 with Duct Firing
ICE	East / West	Internal Combustion Engine
IC Aero	East / West	Simple Cycle Combustion Turbine Intercooled Aero
SCCT Aero	East / West	Simple Cycle Combustion Turbine Aero Dérivative
SCCT Frame	East / West	Simple Cycle Combustion Turbine Frame
Geothermal	East / West	Geothermal (East-Blundell,East-Greenfield, West-Greenfield)
Nuclear	East / West	Nuclear
Battery Storage	East / West	Battery Storage
Utility Biomass	East / West	Utility Biomass
CAES	East / West	Compressed Air Energy Storage
CHP - Biomass	East / West	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	East / West	Combined Heat and Power - Reciprocating Engine
CHP - Kern River	East / West	Combined Heat and Power - Kern River (Recovered Energy Generation)
CHP - Other	East / West	Combined Heat and Power - Other
Distributed Standby Generation	East / West	Distributed Standby Generation
Fuel Cell	East / West	Fuel Cell
Pump Storage	East / West	Pump Storage
Wave	West	Wave (Hydrokinetic)
Solar	East / West	Solar Concentrating (PV)
Solar Gas	East / West	Solar Concentrating (PV, Natural Gas Backup)
Solar Storage	East / West	Solar Concentrating (Trough, Thermal Storage)
Micro Solar	East / West	Micro Solar - Roof-top PV
DSM, Class 1, UT-Coolkeeper	East / West	DSM - Class 1 - Utah Coolkeeper
DSM, Class 1, [Bubble]-Curtail *	East / West	IRP DSM Class 1 *[Bubble] Curtailment*
DSM, Class 1, [Bubble]-DLC-Com *	East / West	IRP DSM Class 1 *[Bubble] Direct Load Control-Commercial*

Plant	Side	Description
DSM, Class 1, [Bubble]-DLC-RES *	East / West	IRP DSM Class 1 *[Bubble] Direct Load Control-Residential*
DSM, Class 1, [Bubble]-DLC-WH *	East / West	IRP DSM Class 1 *[Bubble] Direct Load Control-Water Heater*
DSM, Class 1, [Bubble]-Irrigate *	East / West	IRP DSM Class 1 *[Bubble] Irrigation*
DSM, Class 1, [Bubble]-Sch-TES *	East / West	IRP DSM Class 1 *[Bubble] Scheduled-Thermal Energy Storage*
DSM, Class 3, [Bubble]-CPP-CI *	East / West	IRP DSM Class 3 *[Bubble] Critical Peak Pricing-Small commercial*
DSM, Class 3, [Bubble]-CPP-RES *	East / West	IRP DSM Class 3 *[Bubble] Critical Peak Pricing-Residential*
DSM, Class 3, [Bubble]-DemandB *	East / West	IRP DSM Class 3 *[Bubble] Demand Buyback-Ind/Comm*
DSM, Class 3, [Bubble]-RTP-CI *	East / West	IRP DSM Class 3 *[Bubble] Time-of-Use - Small Commercial*
DSM, Class 3, [Bubble]-TOU-RES *	East / West	IRP DSM Class 3 *[Bubble] Time-of-Use - Residential*
DSM, Class 2, [Bubble]	East	DSM, Class 2, - *Goshen, Utah, Total Wyoming, Washington, West Main, Yakima*
Wind, *[Bubble]*, 24	East / West	*[Bubble]* Wind 24% Capacity Factor
Wind, *[Bubble]*, 29	East / West	*[Bubble]* Wind 29% Capacity Factor
Wind, *[Bubble]*, 35	East / West	*[Bubble]* Wind 35% Capacity Factor
Wind, Project I	East	Wind, Project I
Wind, Project II	East	Wind, Project II
Wind, Duke Energy PPA	East	Wind, Duke Energy PPA
Wind, HighPlains	East	Wind, High Plains
Wind PPA	West	Wind Power Purchase Agreement
2012 RFP Lake Side	East	2012 RFP Lake Side 2 ***
East PPA	East	East Power Purchase Agreement
Coal & Gas Capacity Upgrades	East	Coal & Gas Capacity Turbine Upgrades
Coal Plant Turbine Upgrades	West	Coal Plant Turbine Upgrades
Blundell 3	East	Blundell Geothermal 3 (Expansion)
Swift Hydro Upgrades	West	Swift Hydro Upgrades
FOT *[Market Bubble]* Q3 **	East	Front Office Transaction - *3rd Quarter HLH Product*
FOT *[Market Bubble]* Flat **	East	Front Office Transaction - *Flat Annual Product*
Growth Resource *[Bubble]*	East / West	**Growth Resource (Goshen, Utah North, Wyoming, Walla Walla, West Main, Yakima)**

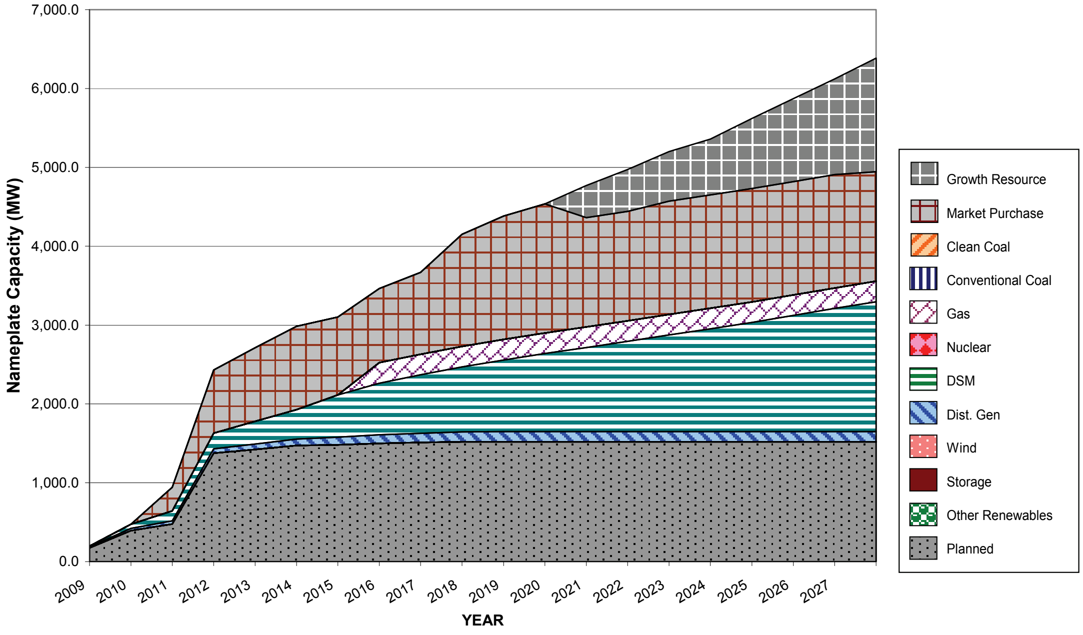
Notes on Market and Topology Bubbles:

Please see the Transmission Topology chart for the "bubbles" used for location of modeled resource options.
**** Topology Bubbles:** Goshen (GO), Utah (UT), WYAE (Wyoming Aeolus), MC (Mid-Columbia), WM (West Main), WW (Walla Walla), YA (Yakima)*
WYSW (Wyoming Southwest)
***** Market Bubble:** Mead, Mona, Utah, California Oregon Border, Mid-Columbia, West Main, Nevada-Utah Border (NUB)*
*** The 2012 RFP Lake Side 2 resource option was removed in February 2009 during the planning process.

AREA CHARTS: PORTFOLIO CAPACITY ADDITIONS BY RESOURCE TYPE

Resource Additions for Case: Case 01

PVRR = $20,045



Notes:

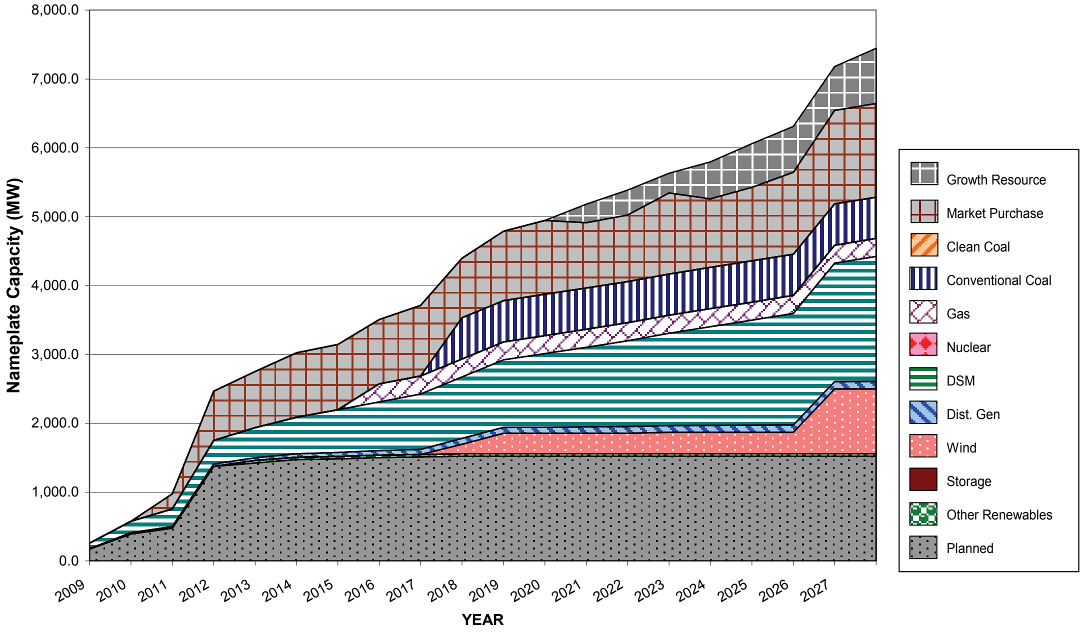
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 02

PVRR = $21,512

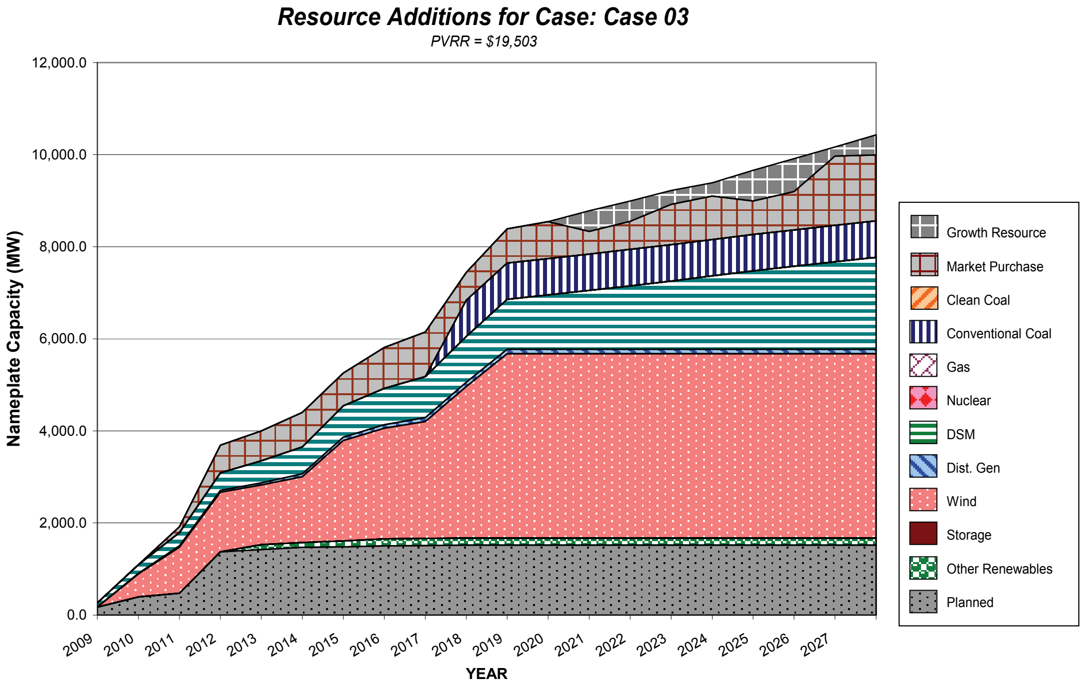


Notes:

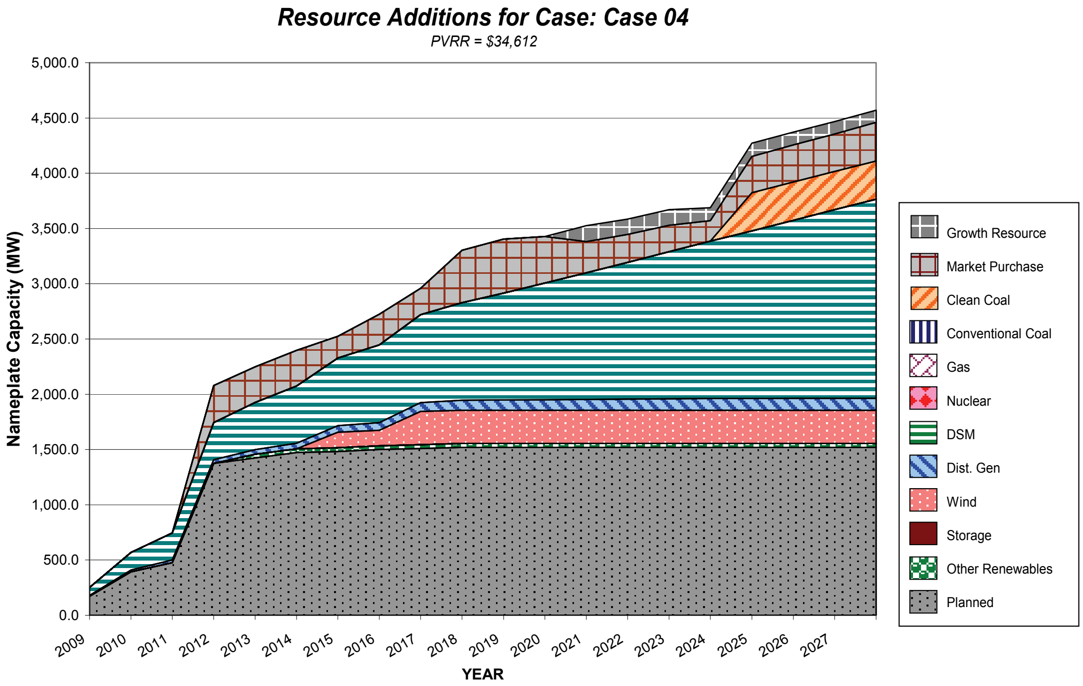
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



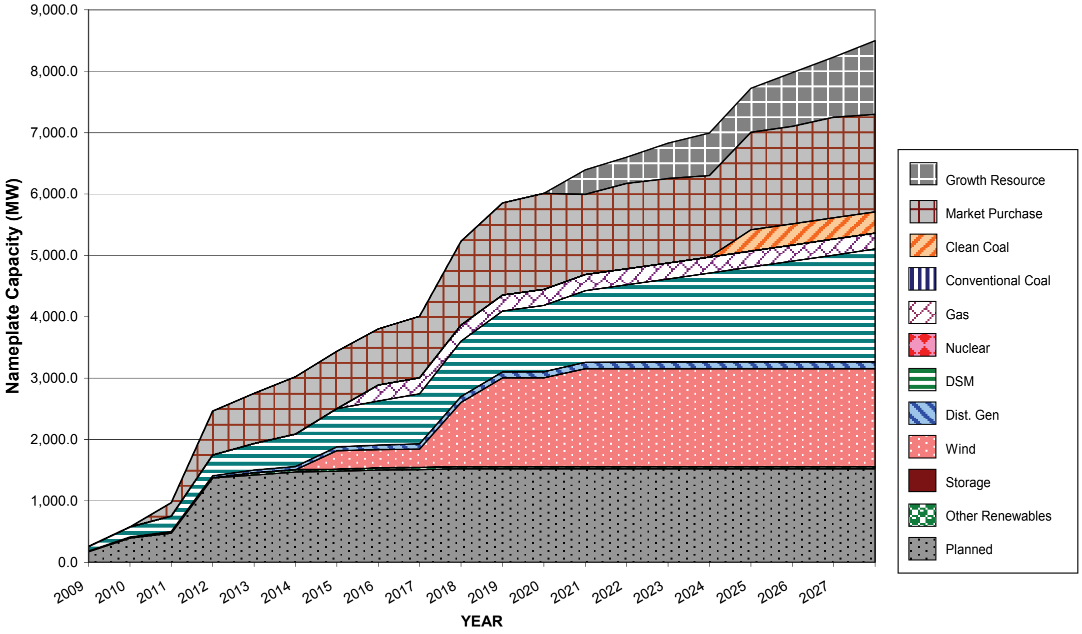
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 05

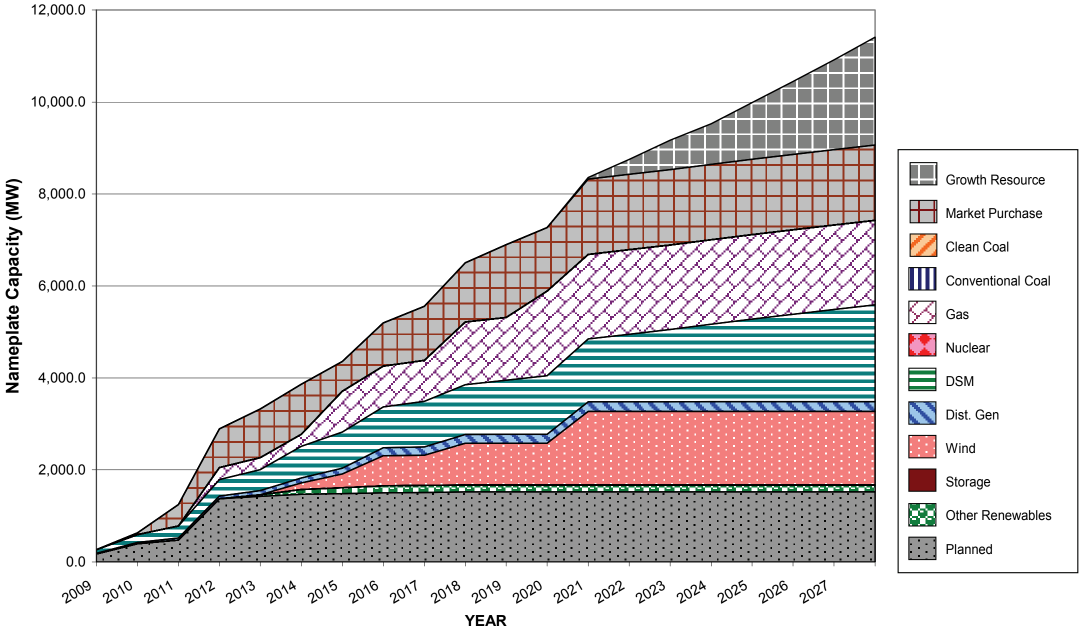
PVRR = $40,526



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 06

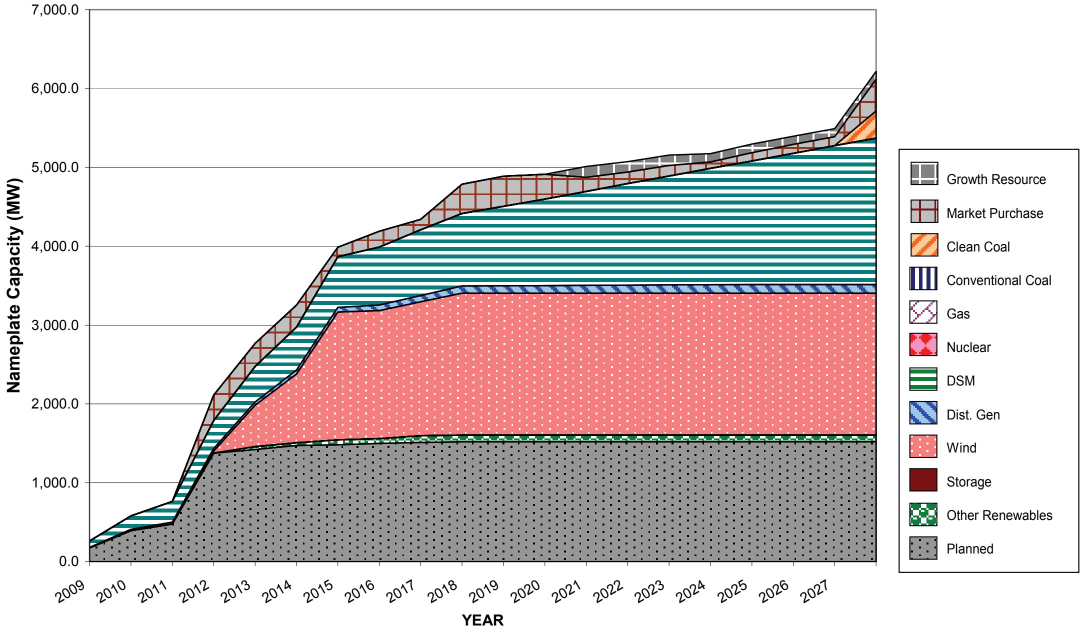
PVRR = $48,140



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 07

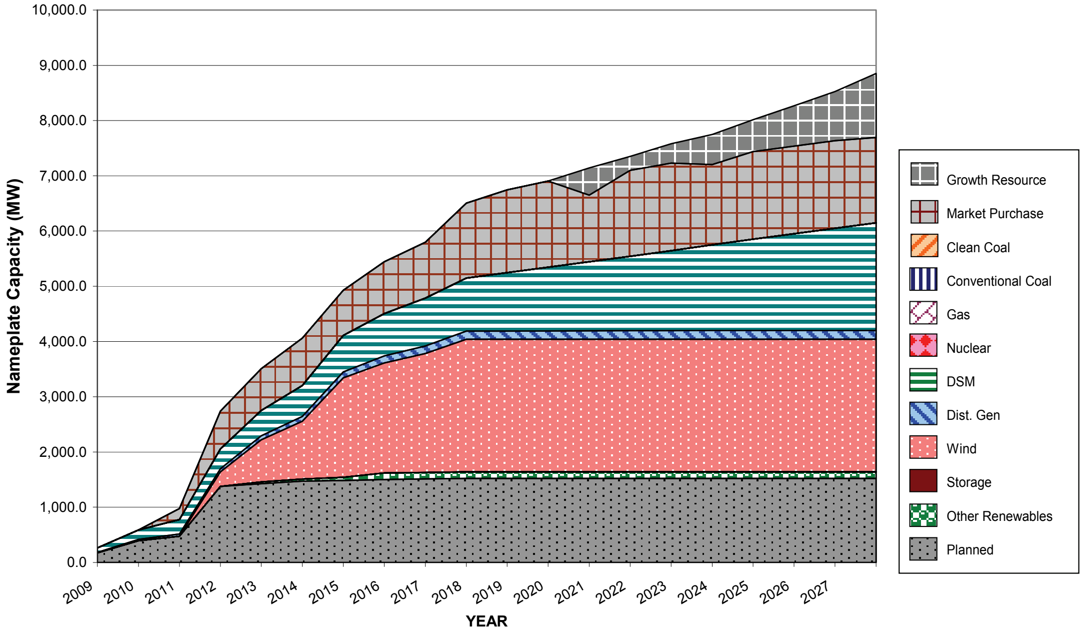
PVRR = $34,582



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 08

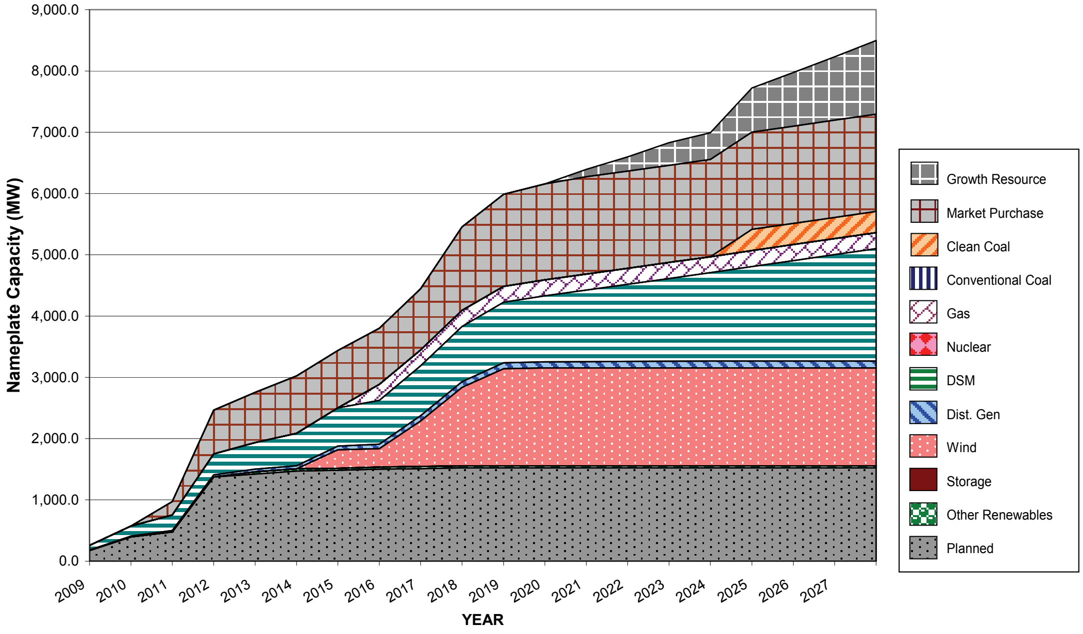
PVRR = $41,372



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 09

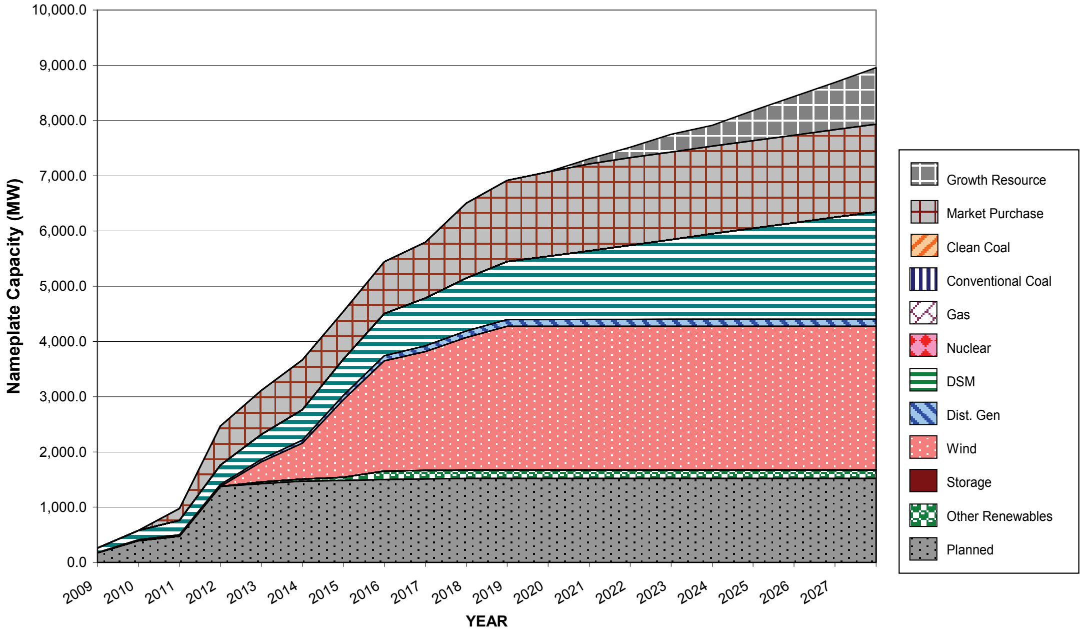
PVRR = $40,204



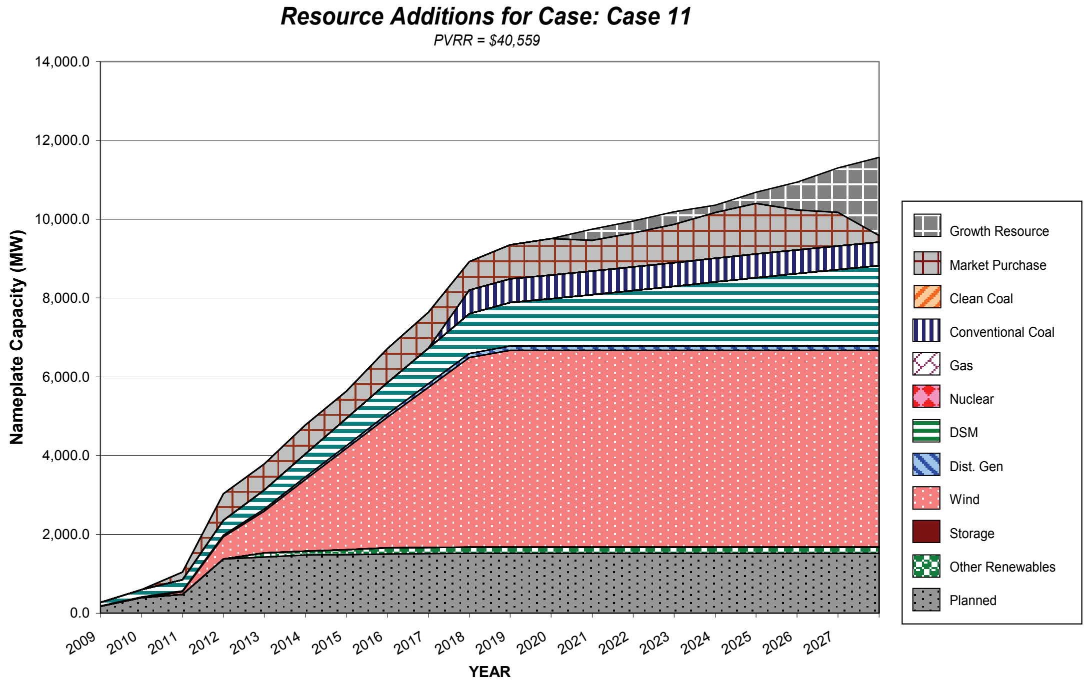
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 10

PVRR = $40,319

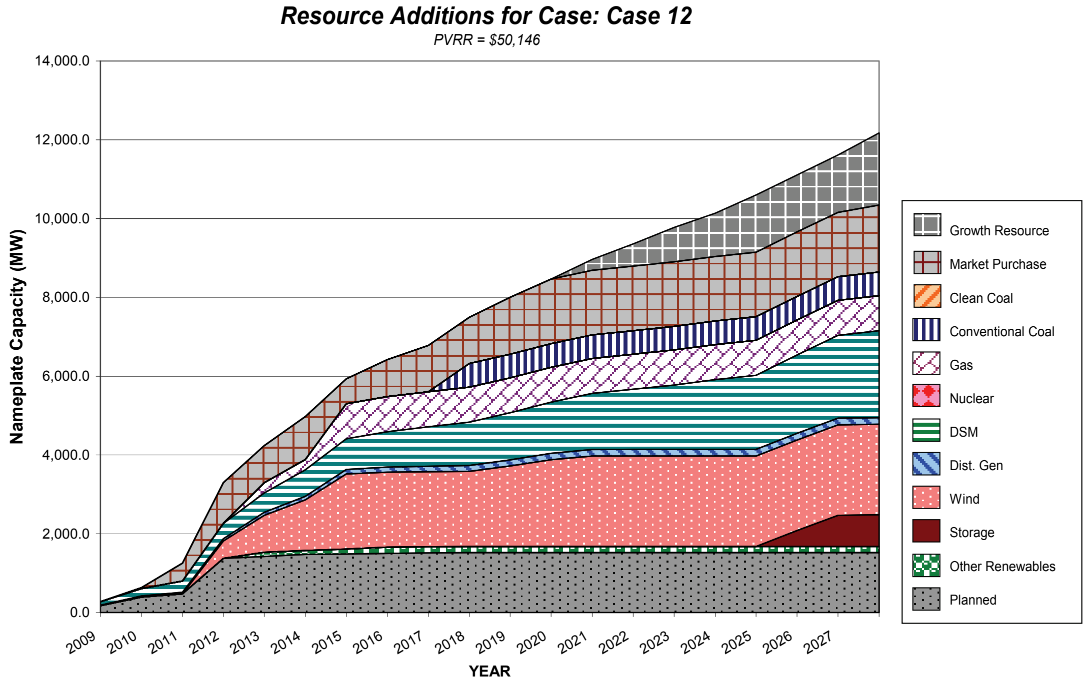


Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).


Resource Additions for Case: Case 11

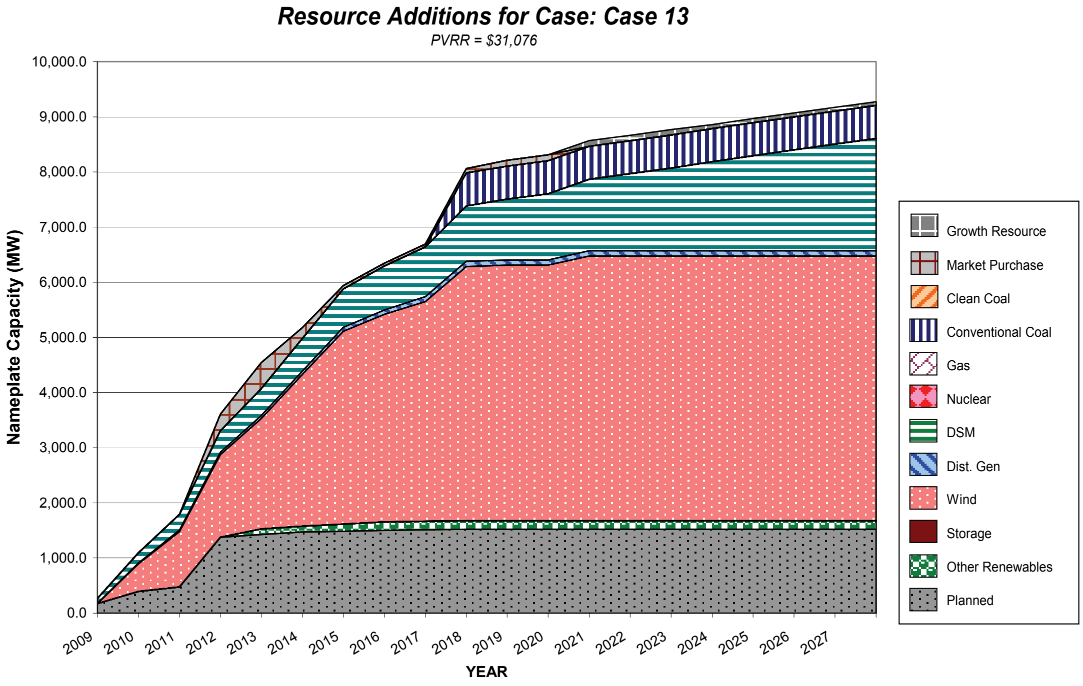
PVRR = $40,559

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

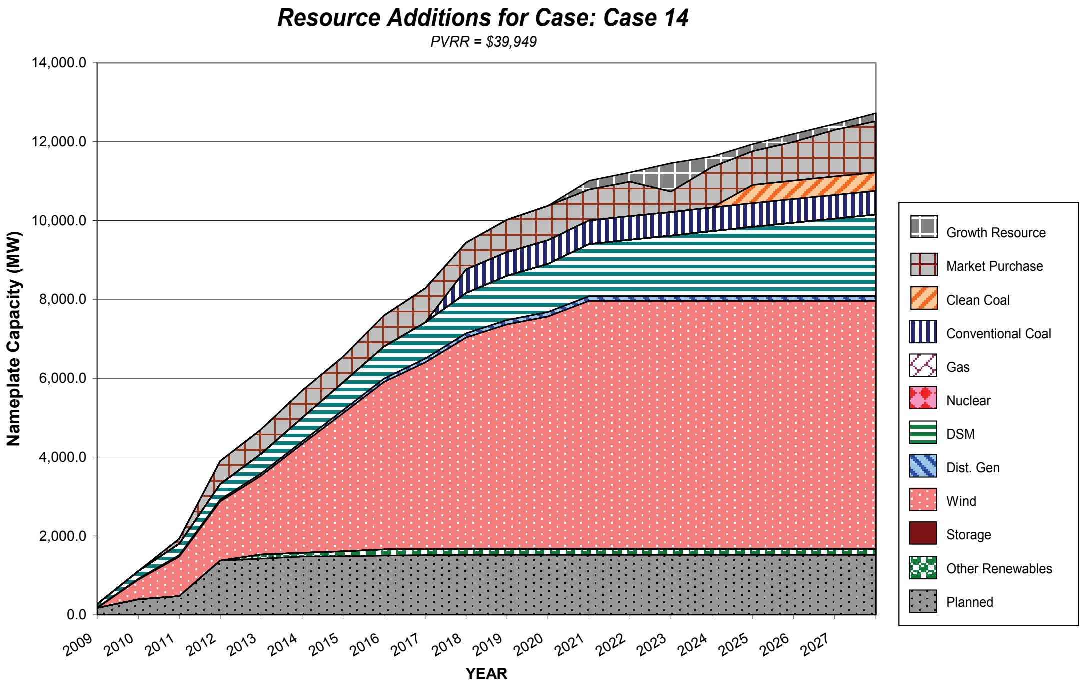

Resource Additions for Case: Case 12

PVRR = $50,146

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



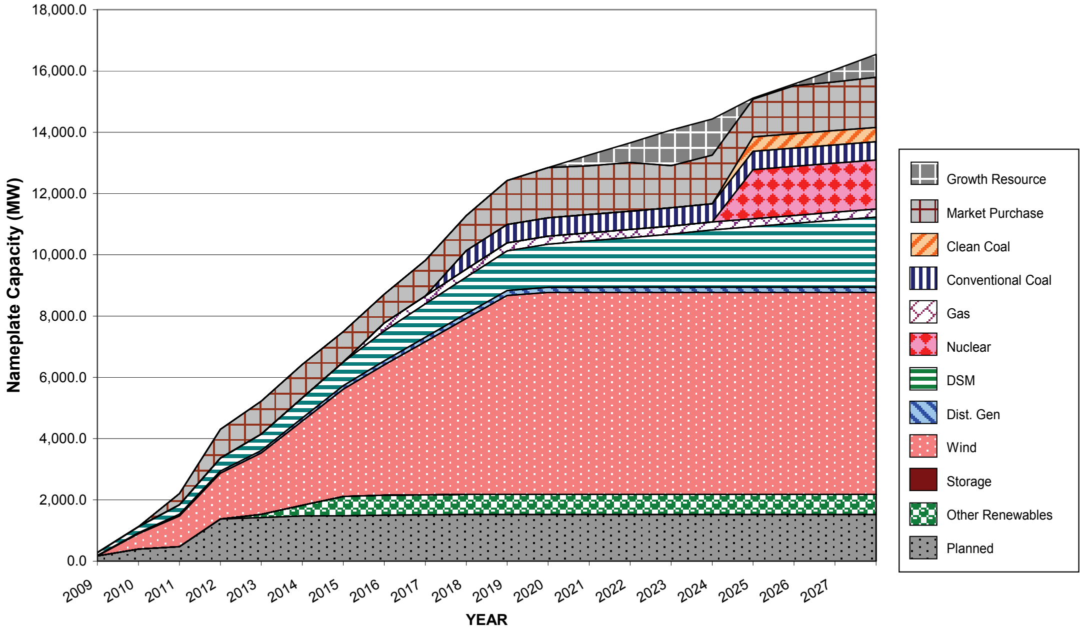
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 15

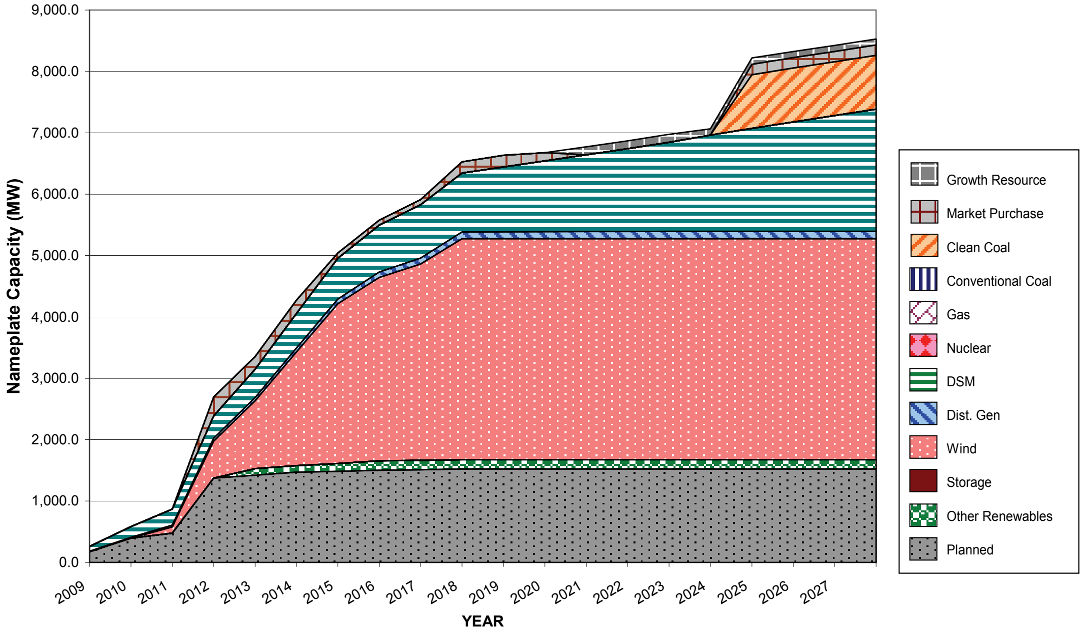
PVRR = $50,914



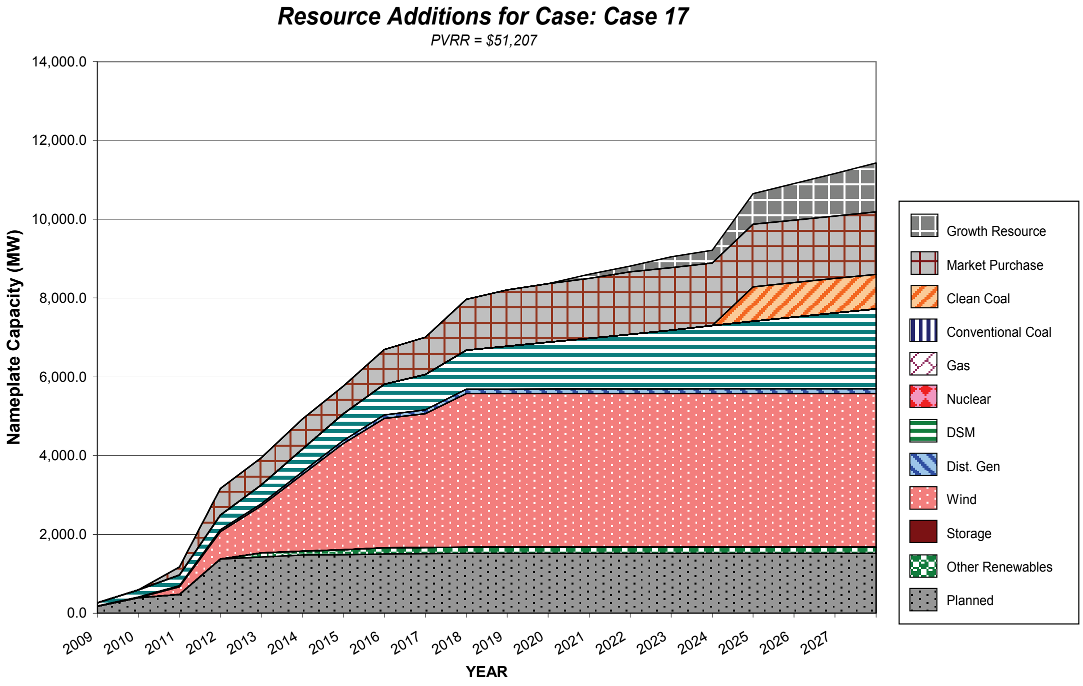
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 16

PVRR = $43,523



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 17

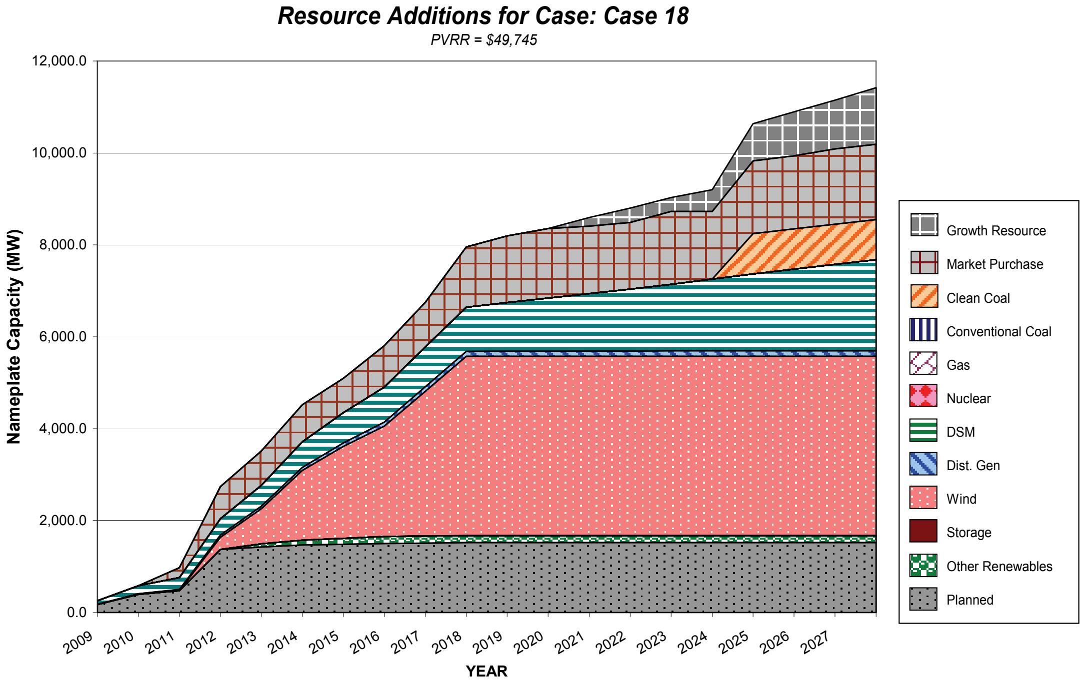
PVRR = $51,207

Notes:

1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 18

PVRR = $49,745

Notes:

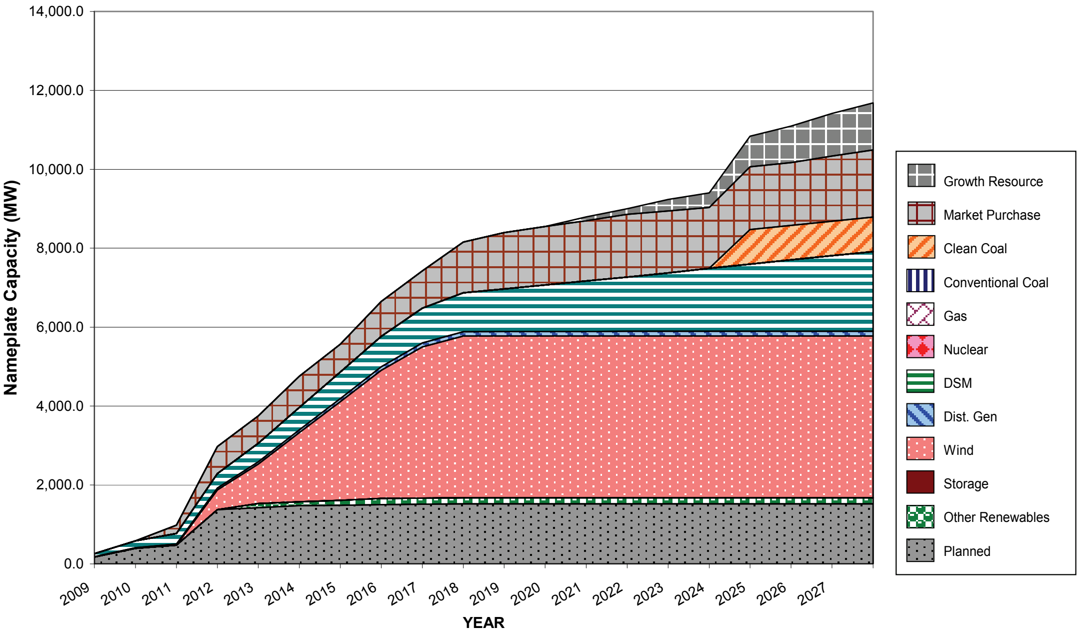
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 19

PVRR = $50,102



Notes:

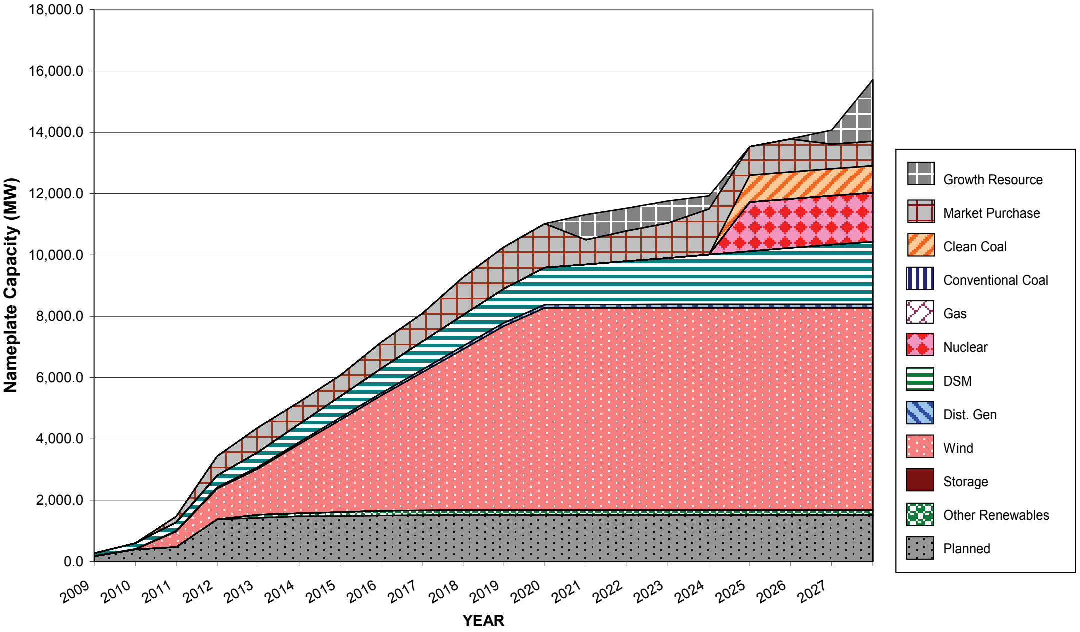
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 20

PVRR = $50,536



Notes:

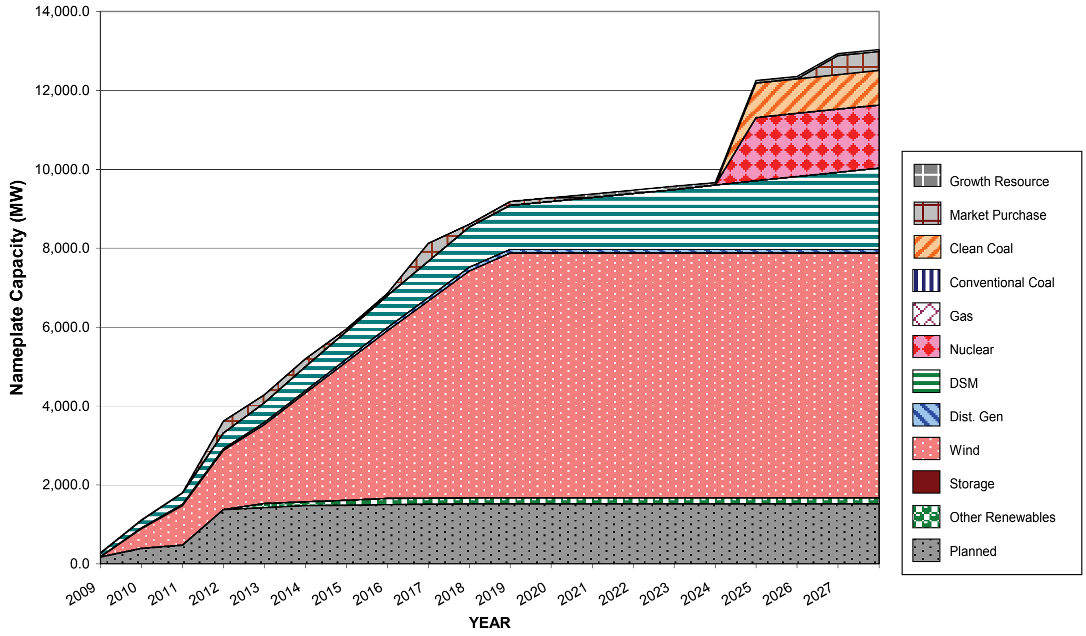
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 21

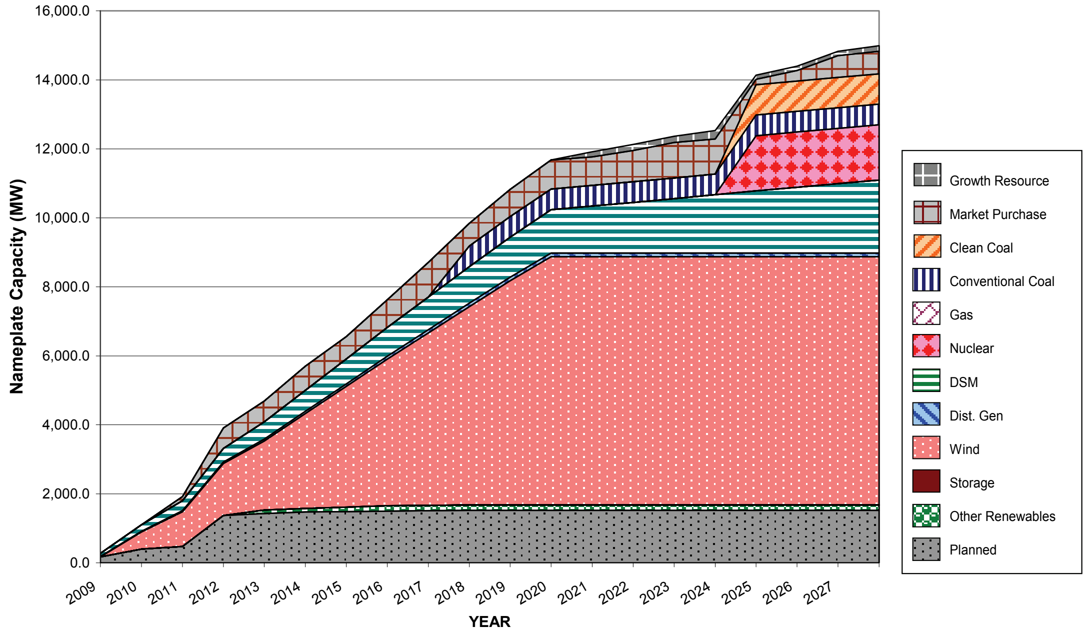
PVRR = $40,517



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 22

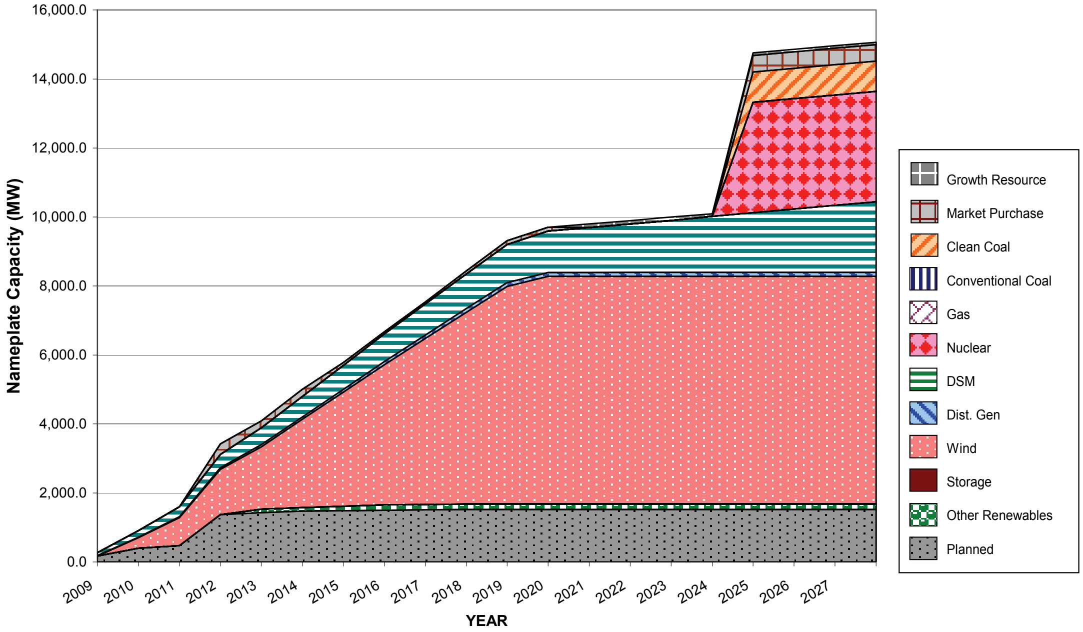
PVRR = $49,983



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 23

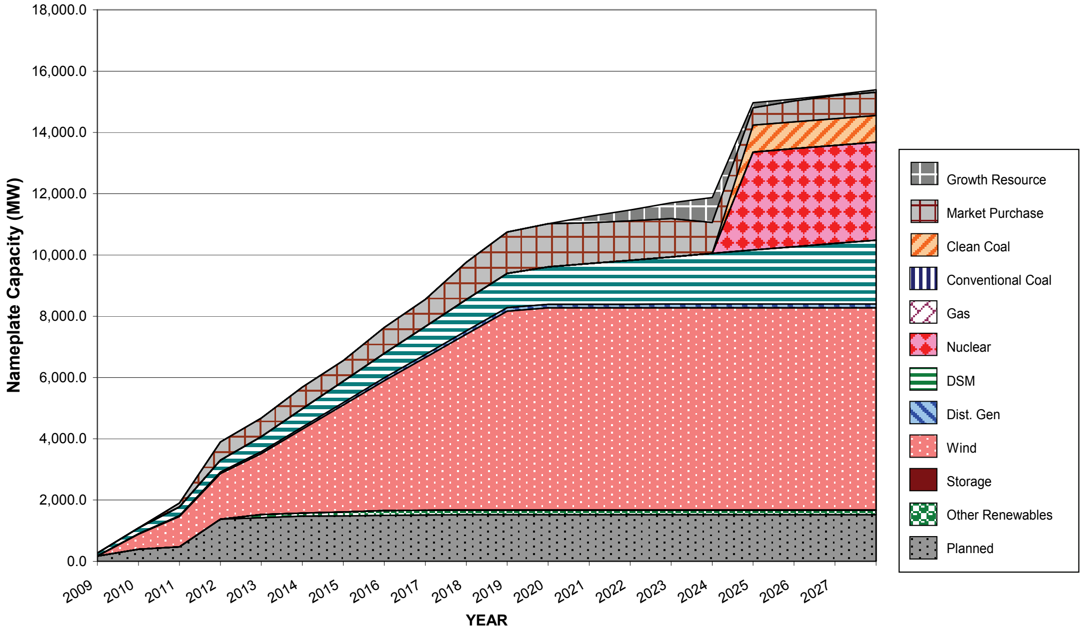
PVRR = $51,692



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 24

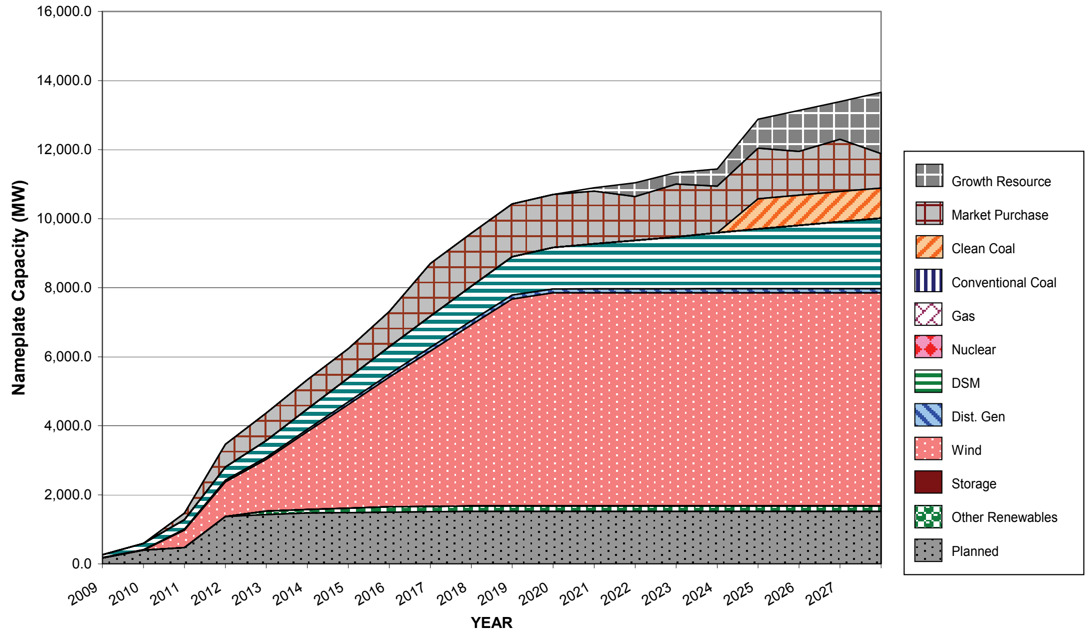
PVRR = $60,693



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 25

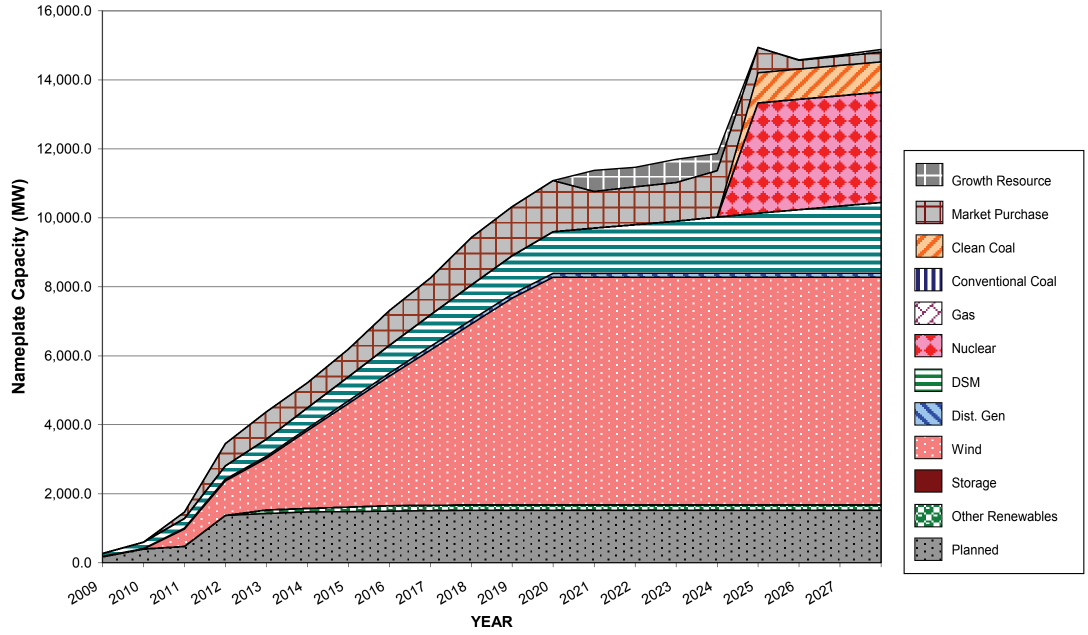
PVRR = $58,838



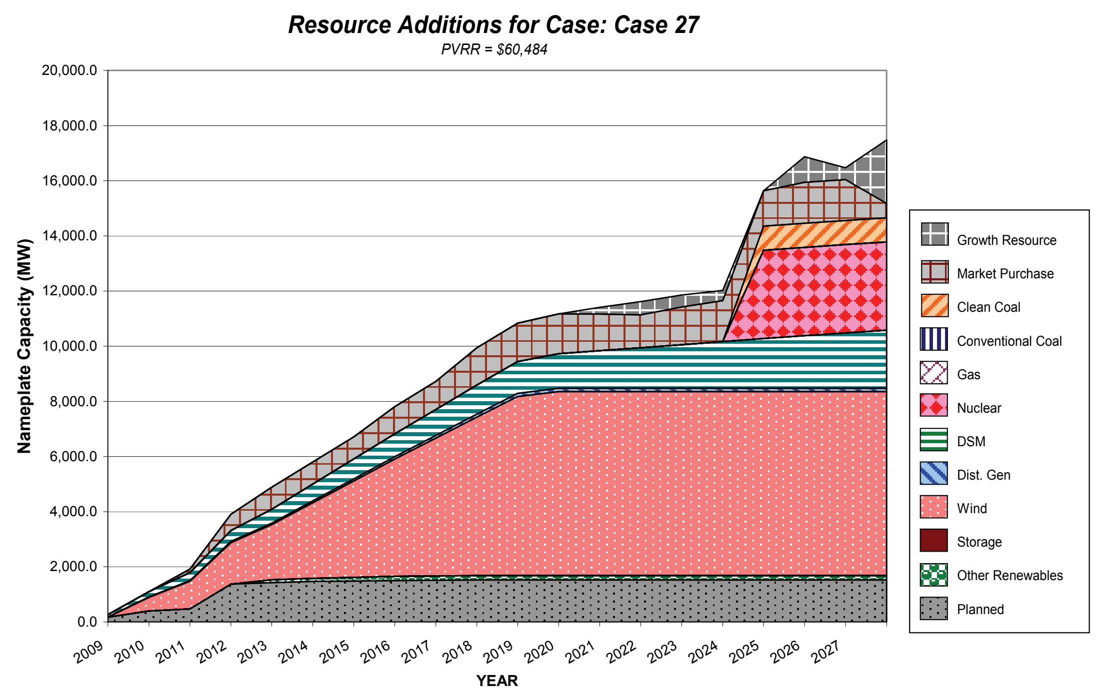
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 26

PVRR = $59,660



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

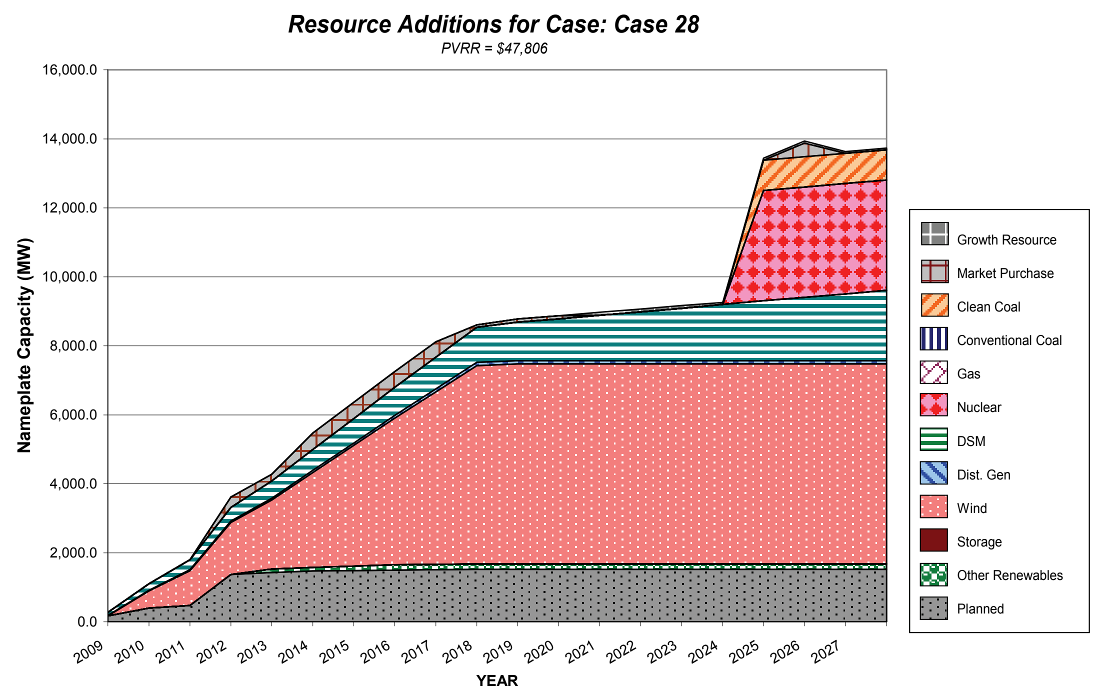


Notes:

1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

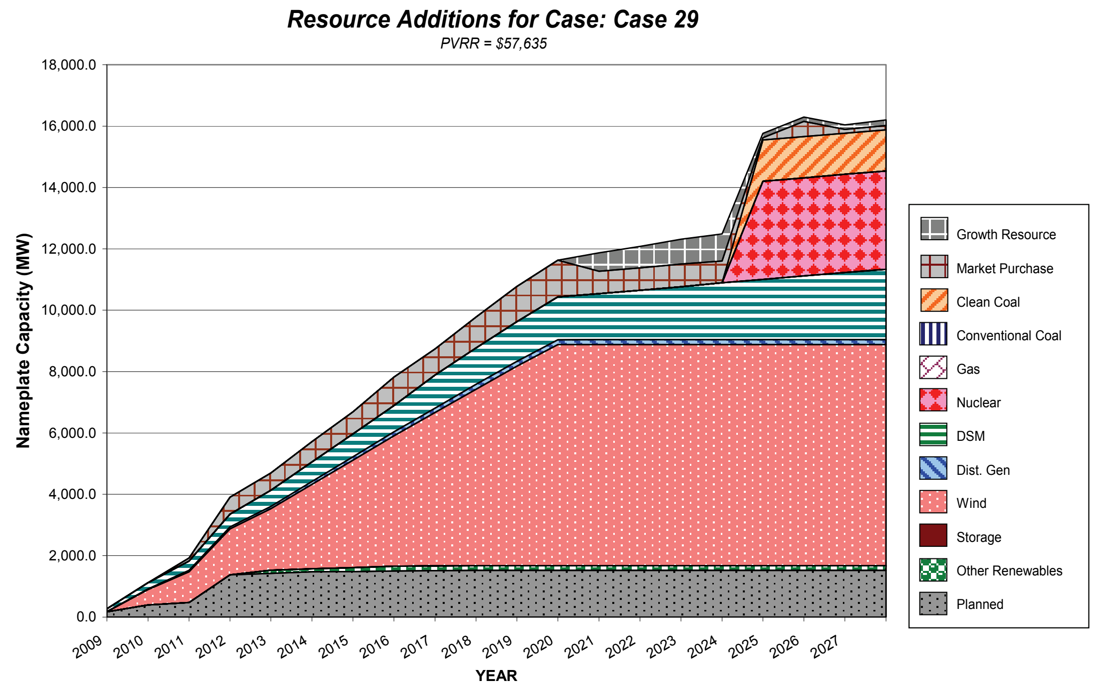


Notes:

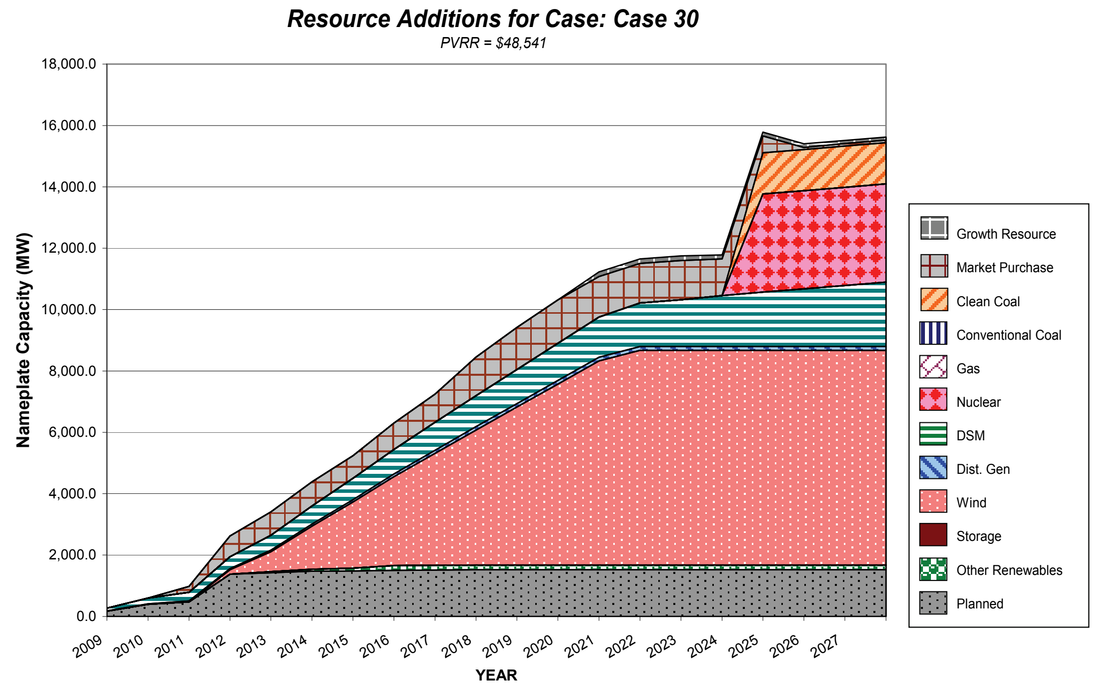
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

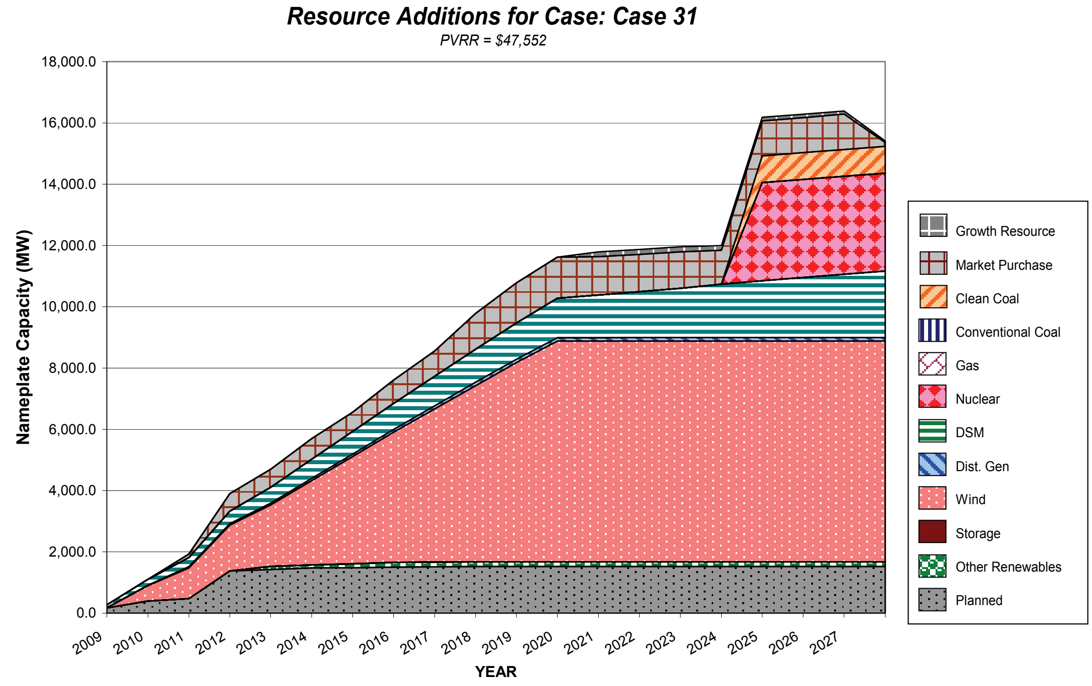
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



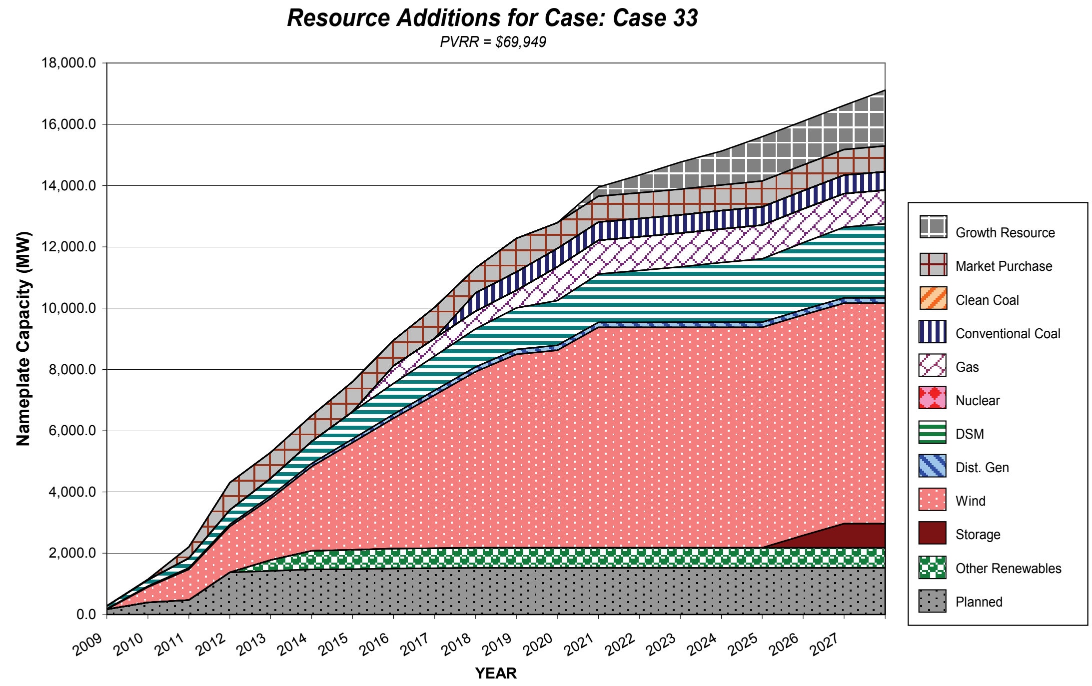
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 31

PVRR = $47,552

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



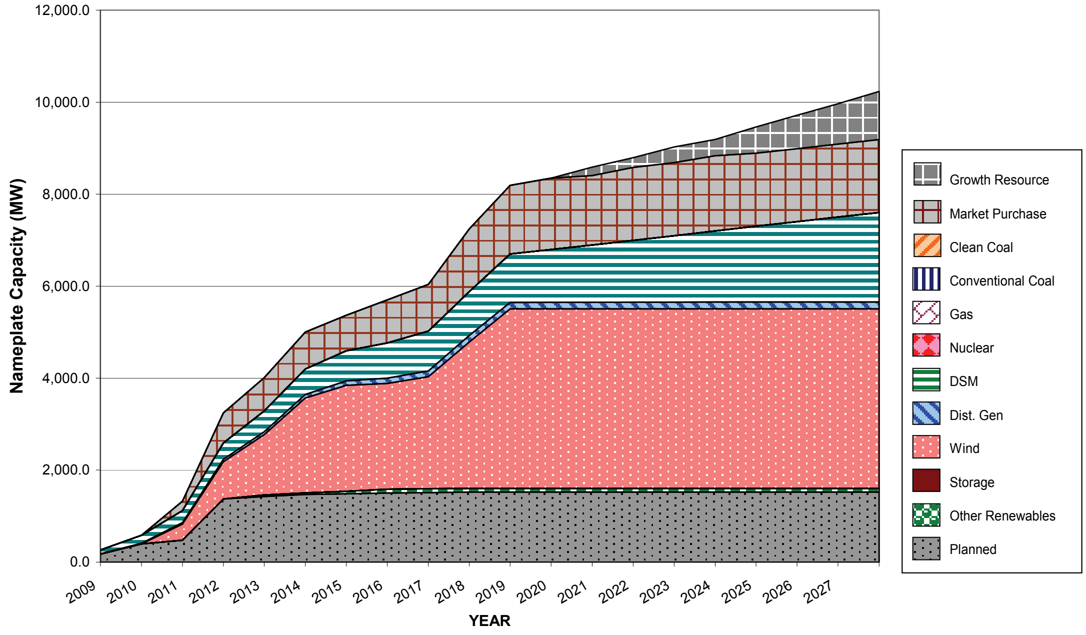
Resource Additions for Case: Case 33

PVRR = $69,949

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 34

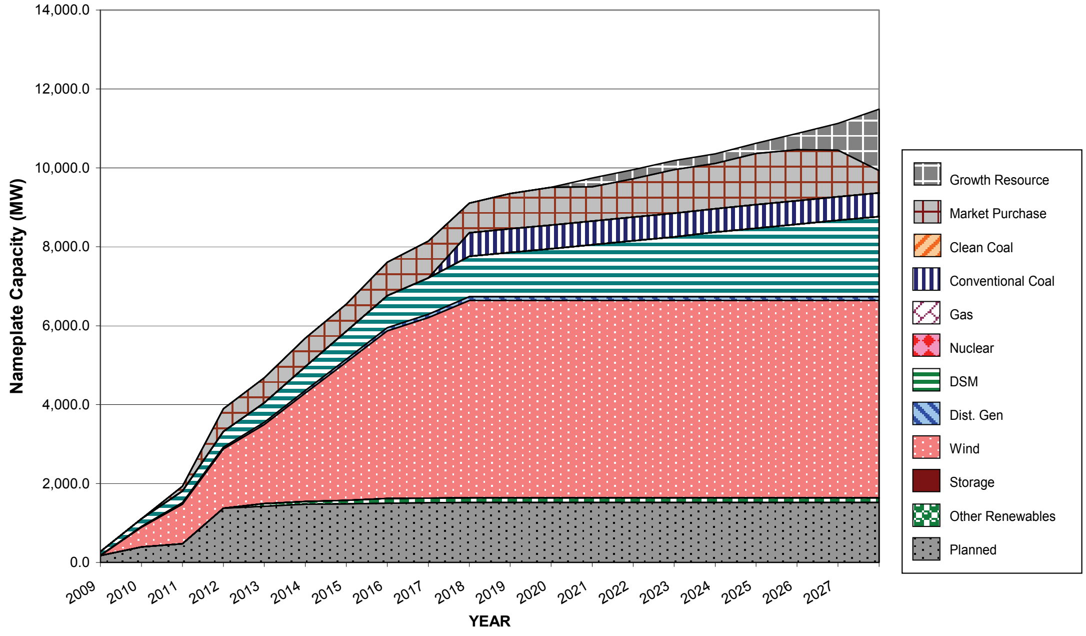
PVRR = $40,564



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 35

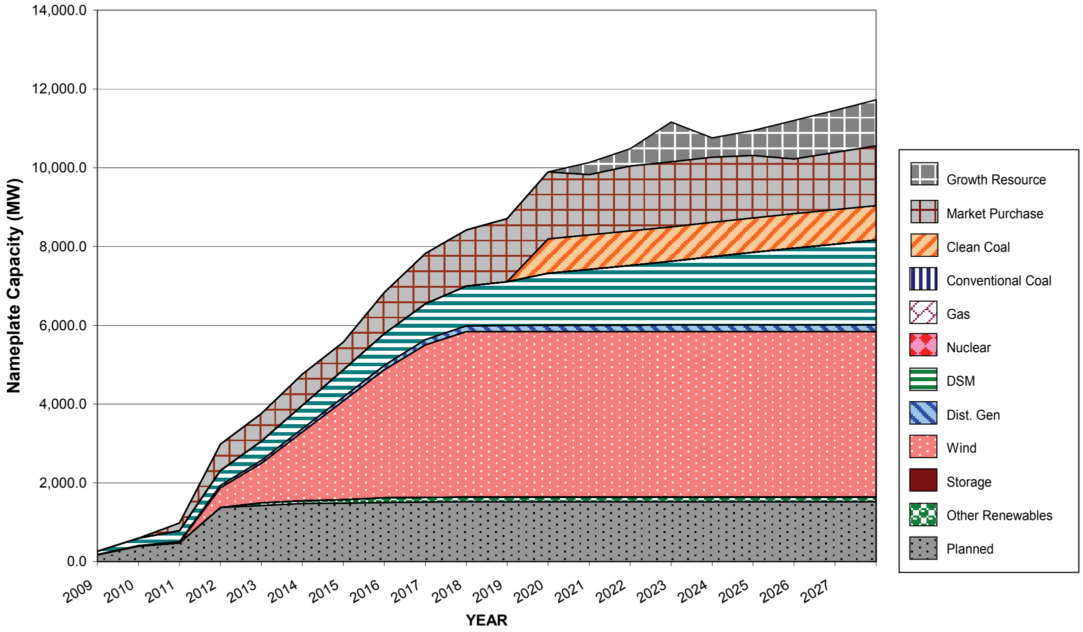
PVRR = $39,853



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 36

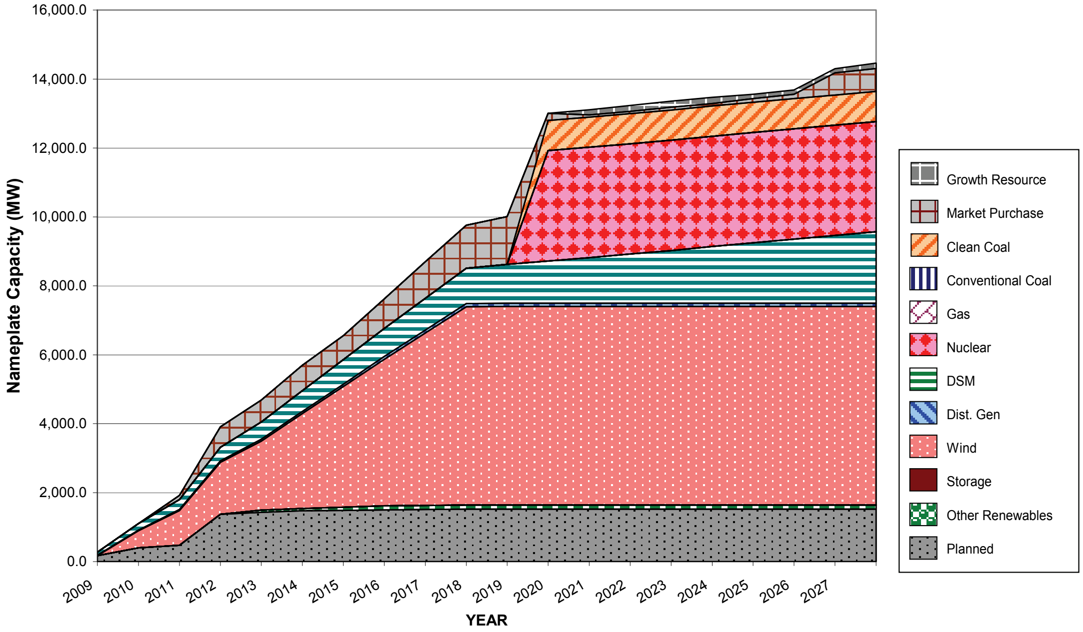
PVRR = $51,242



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 37

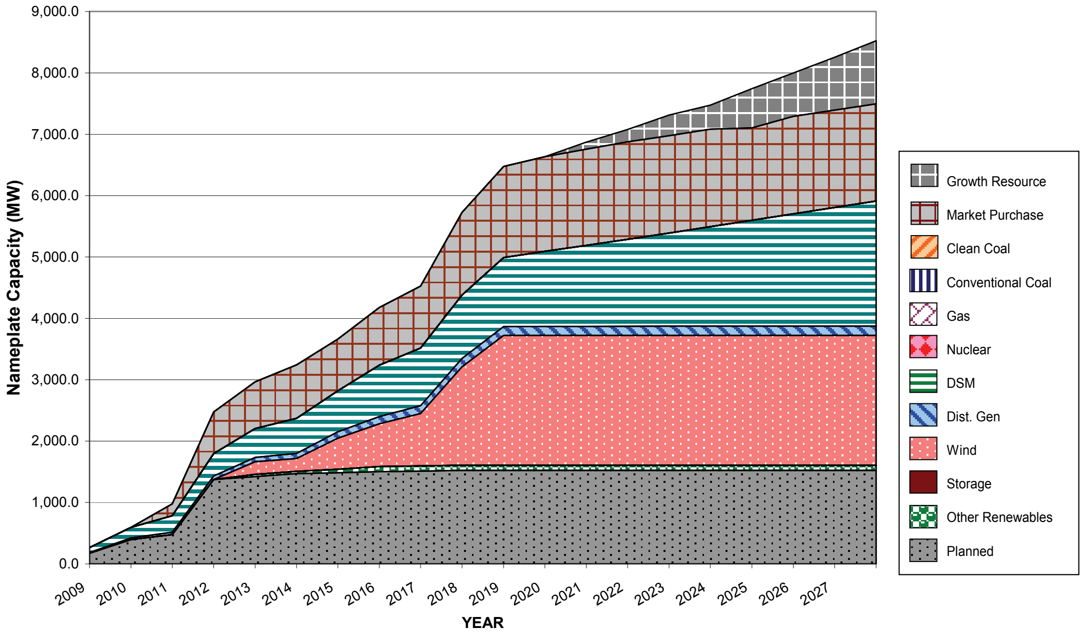
PVRR = $48,949



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 38

PVRR = $41,974



Notes:

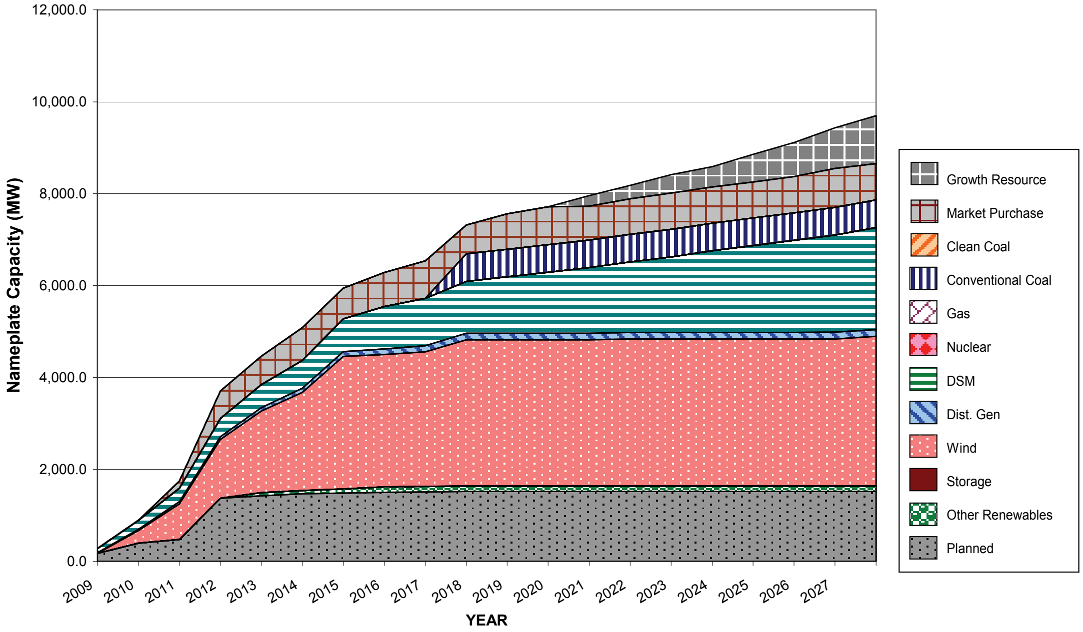
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 39

PVRR = $34,791



Notes:

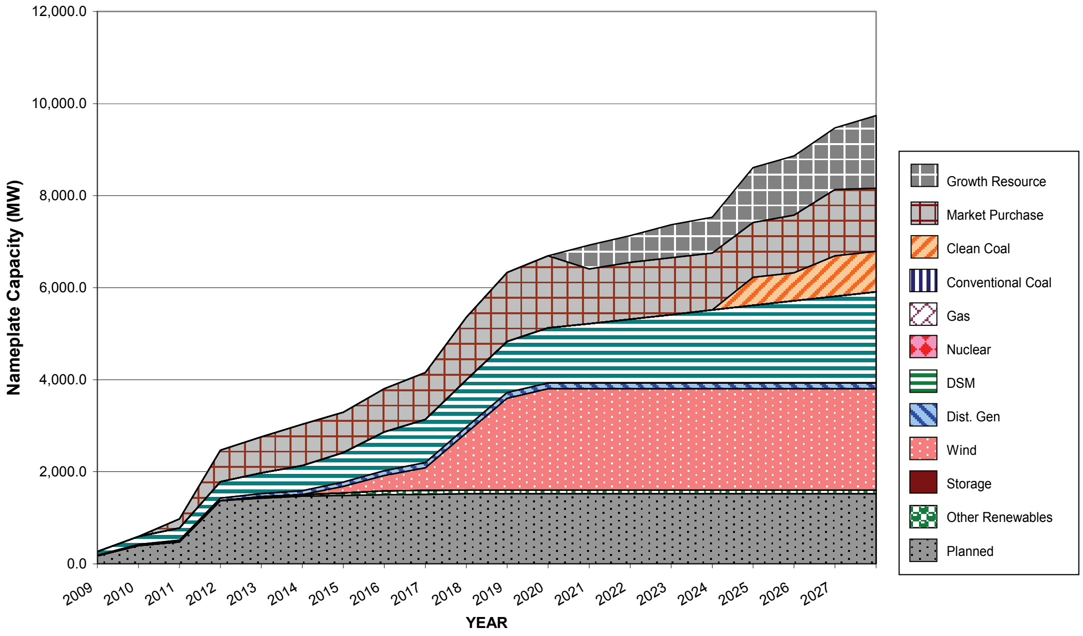
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 40

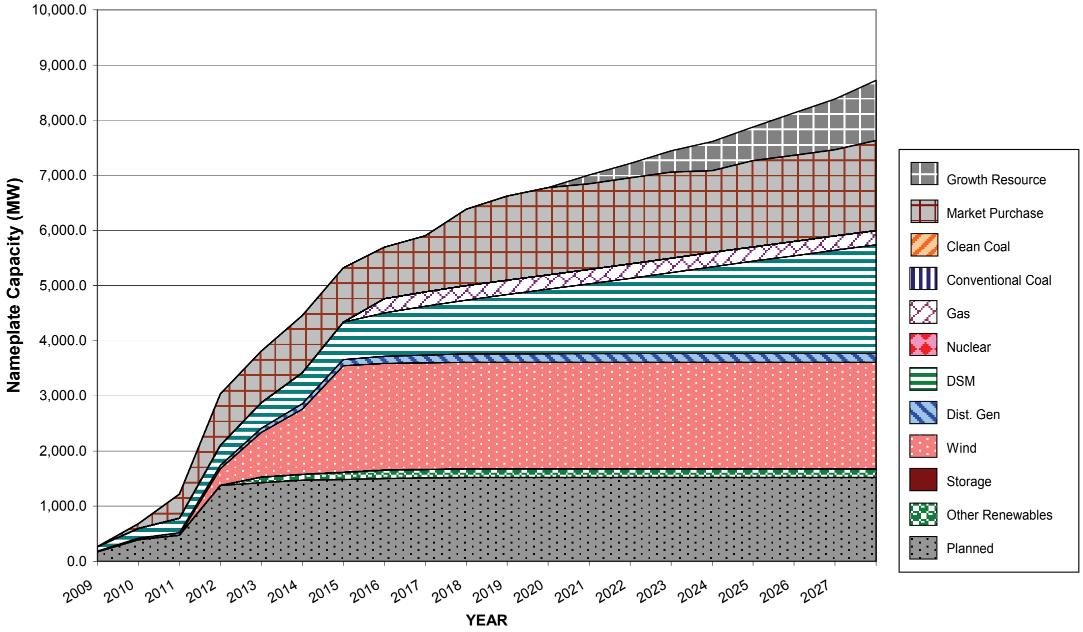
PVRR = $24,761



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 41

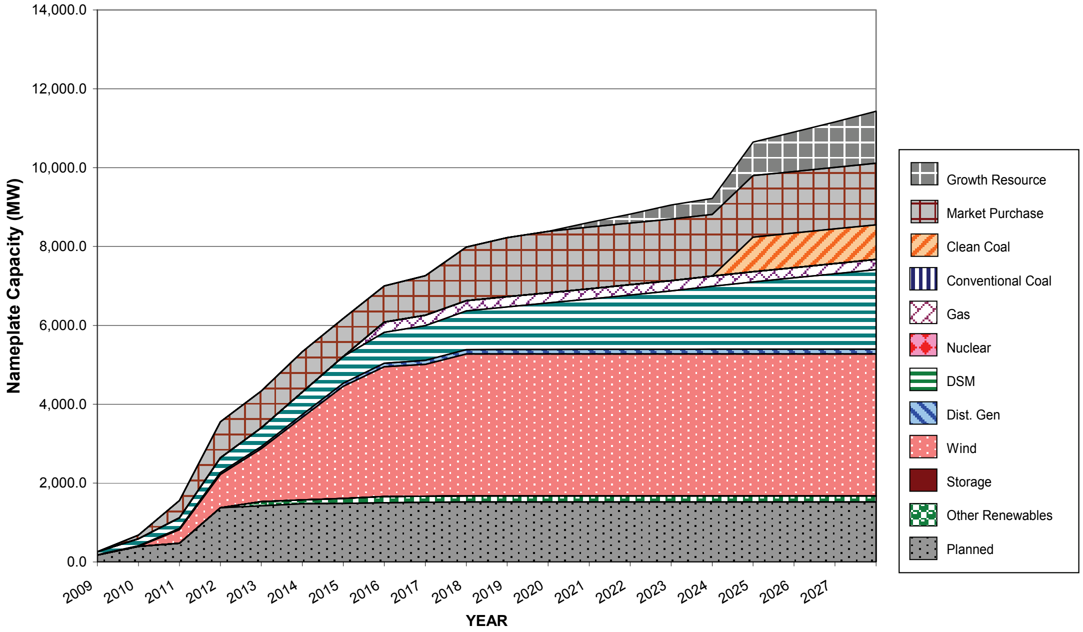
PVRR = $41,542



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 42

PVRR = $51,420



Notes:

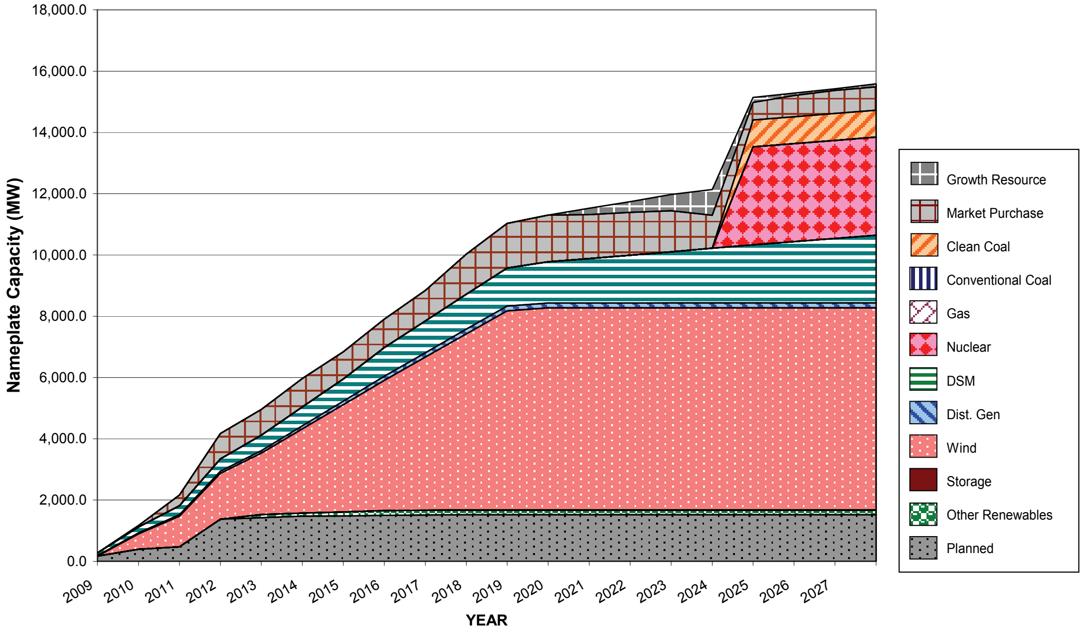
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 43

PVRR = $60,905



Notes:

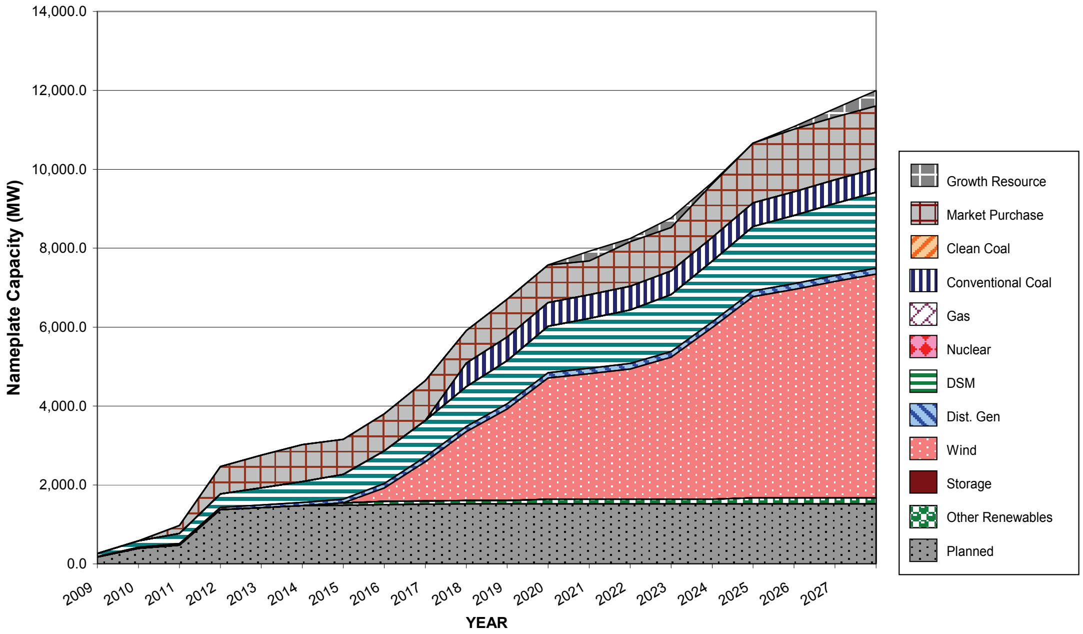
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 44

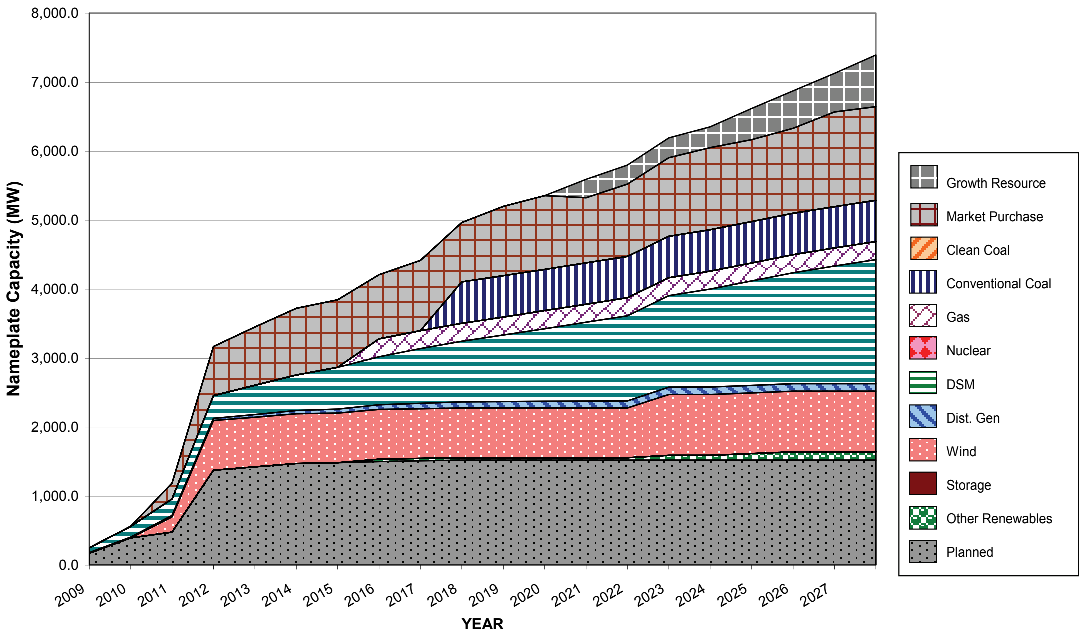
PVRR = $21,249



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 45

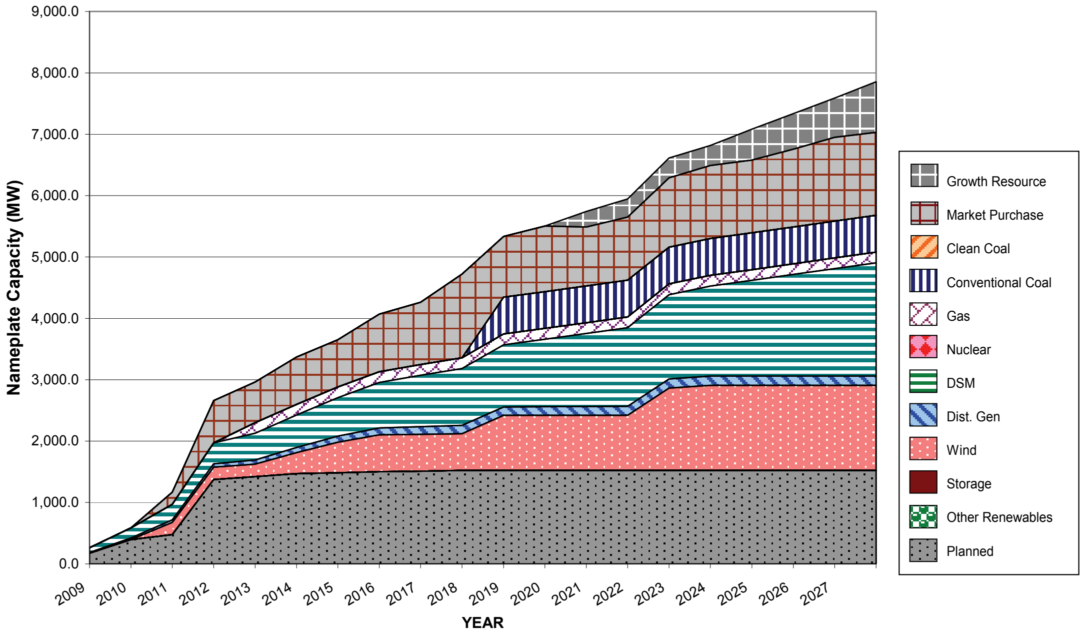
PVRR = $20,875



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 46

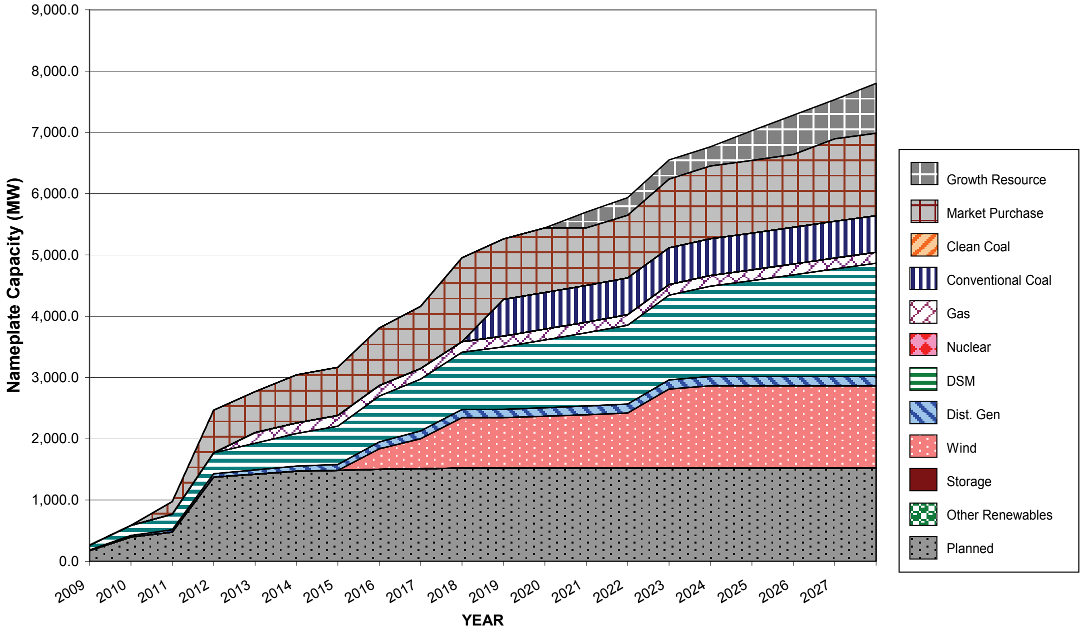
PVRR = $21,532



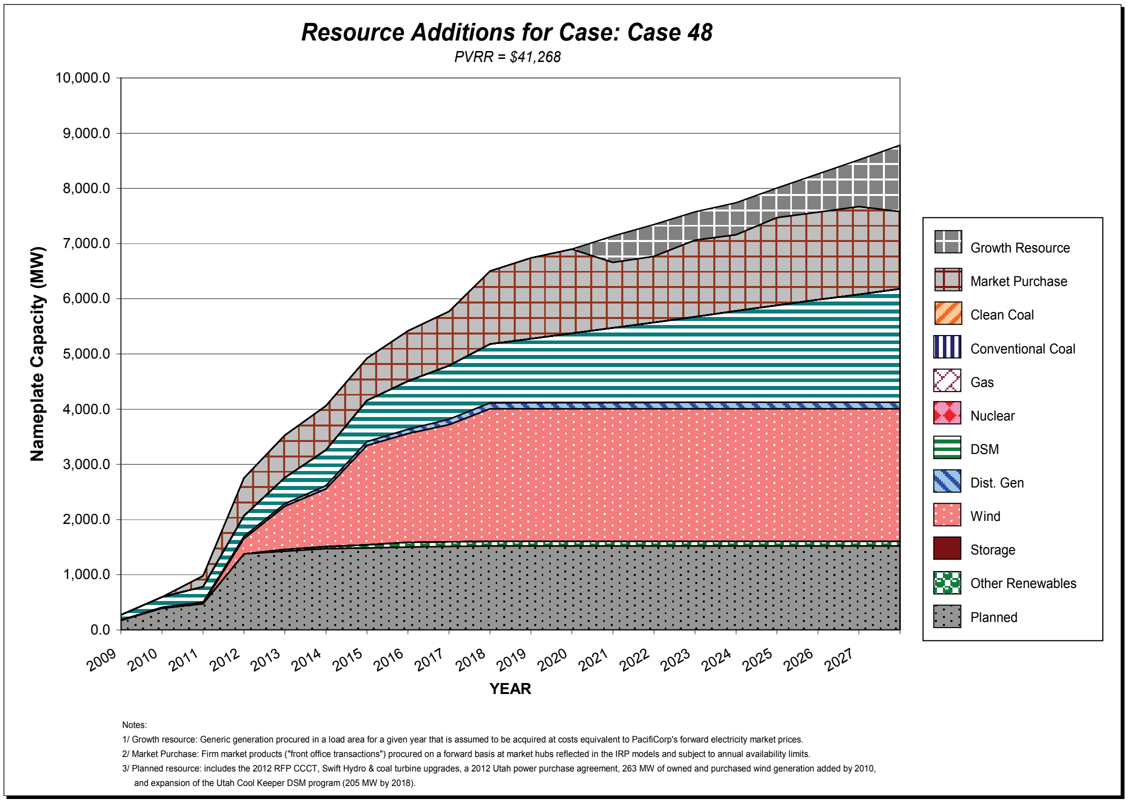
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 47

PVRR = $20,863



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



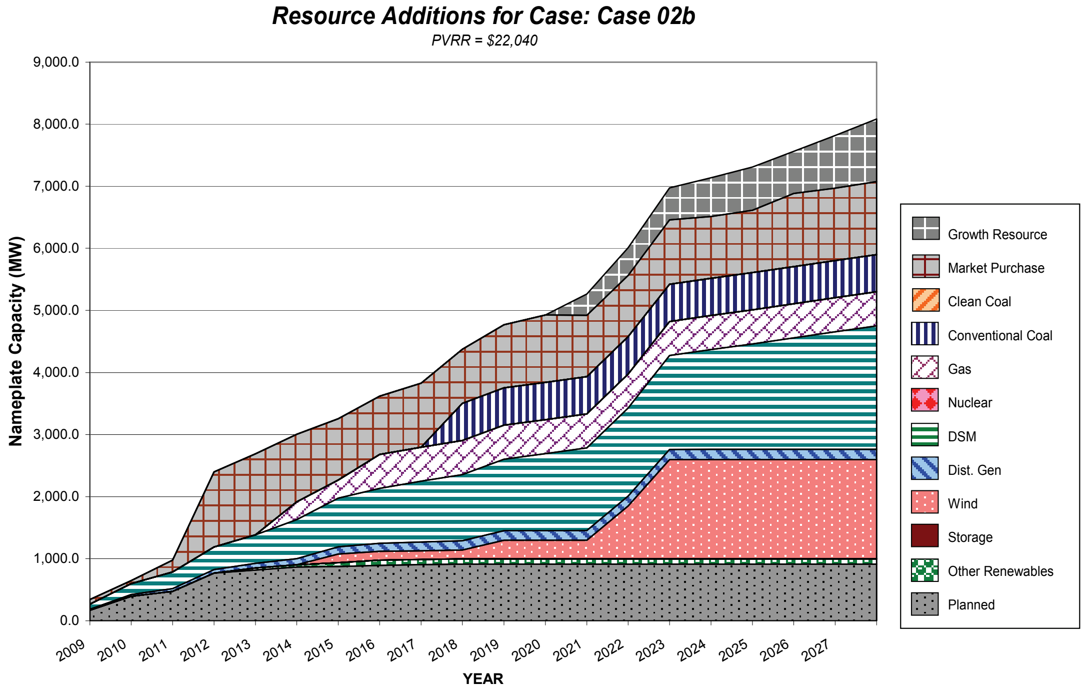
Notes:

1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.

3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

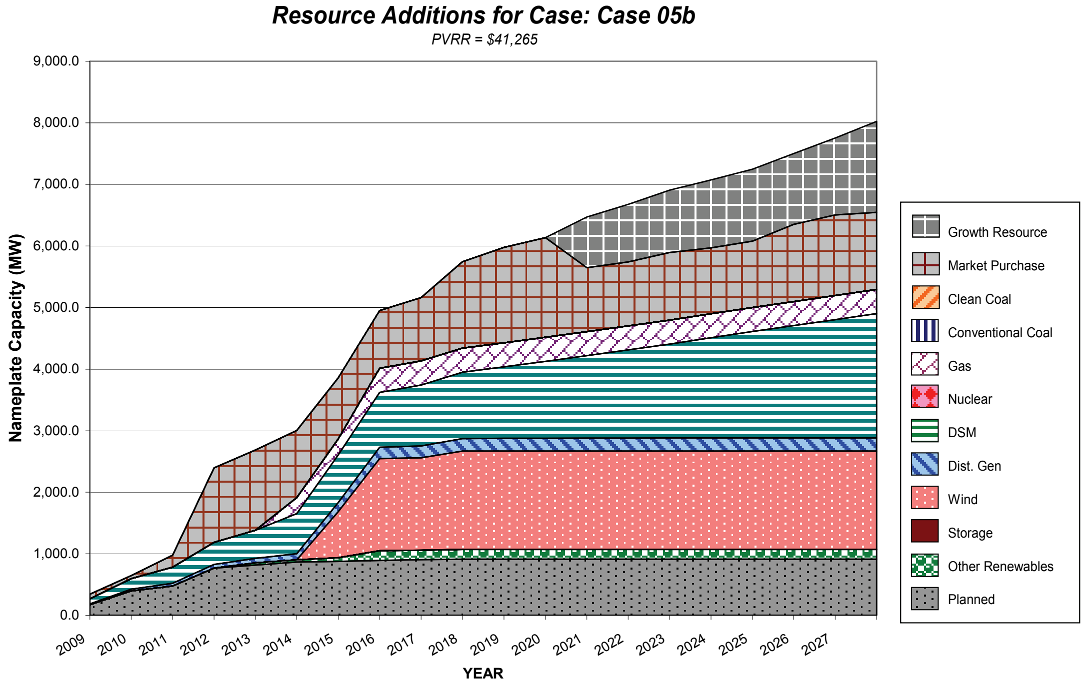
Area Charts: "B-Series" – Portfolio Capacity Additions by Resource Type



Resource Additions for Case: Case 02b

PVRR = $22,040

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



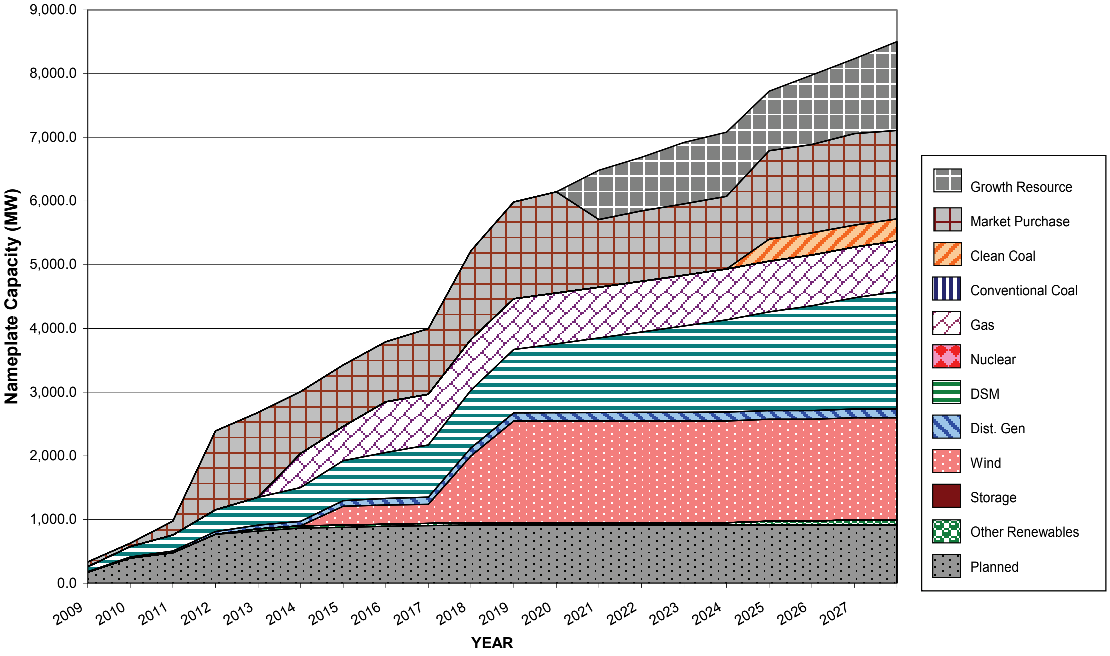
Resource Additions for Case: Case 05b

PVRR = $41,265

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 05b_CCCT

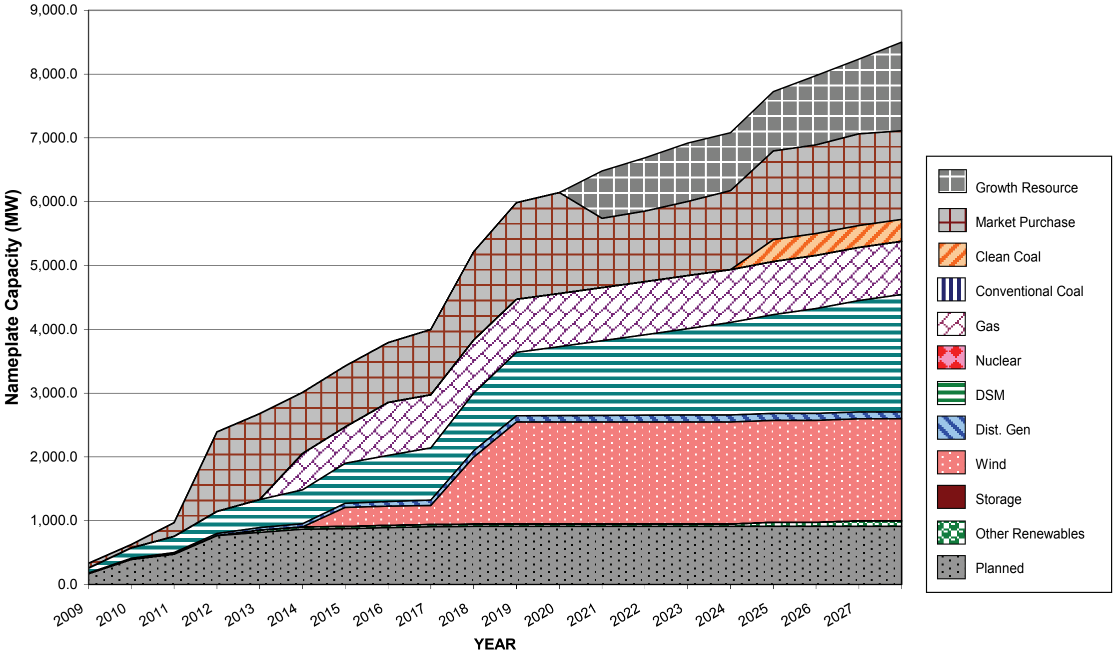
PVRR = $41,325



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 05b_WC_CCCT

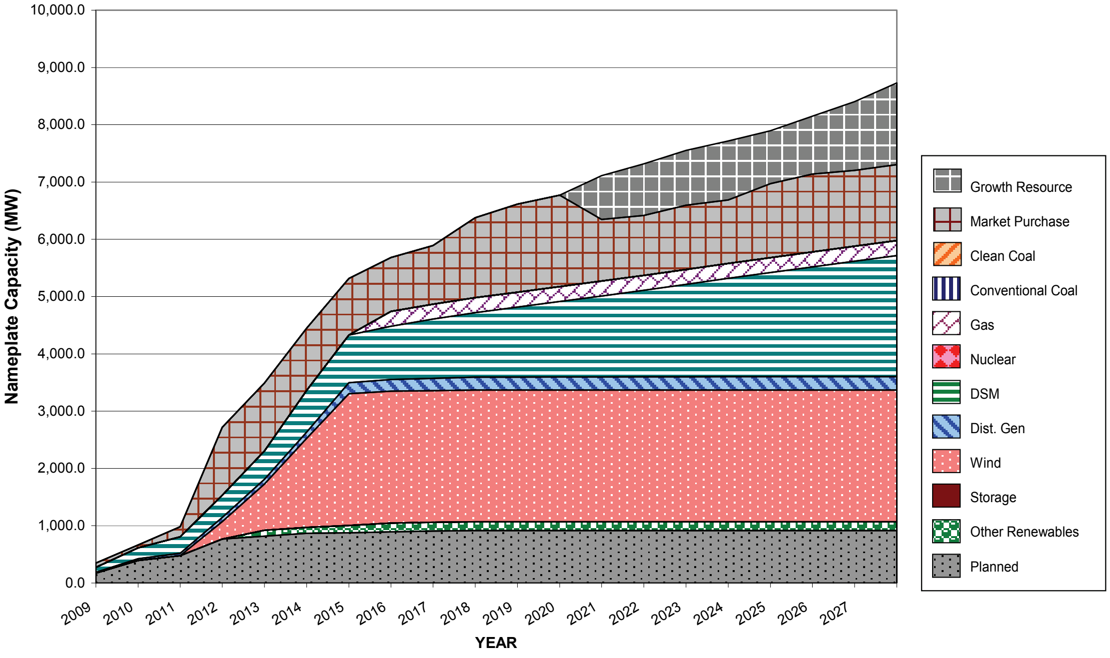
PVRR = $41,271



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 08b

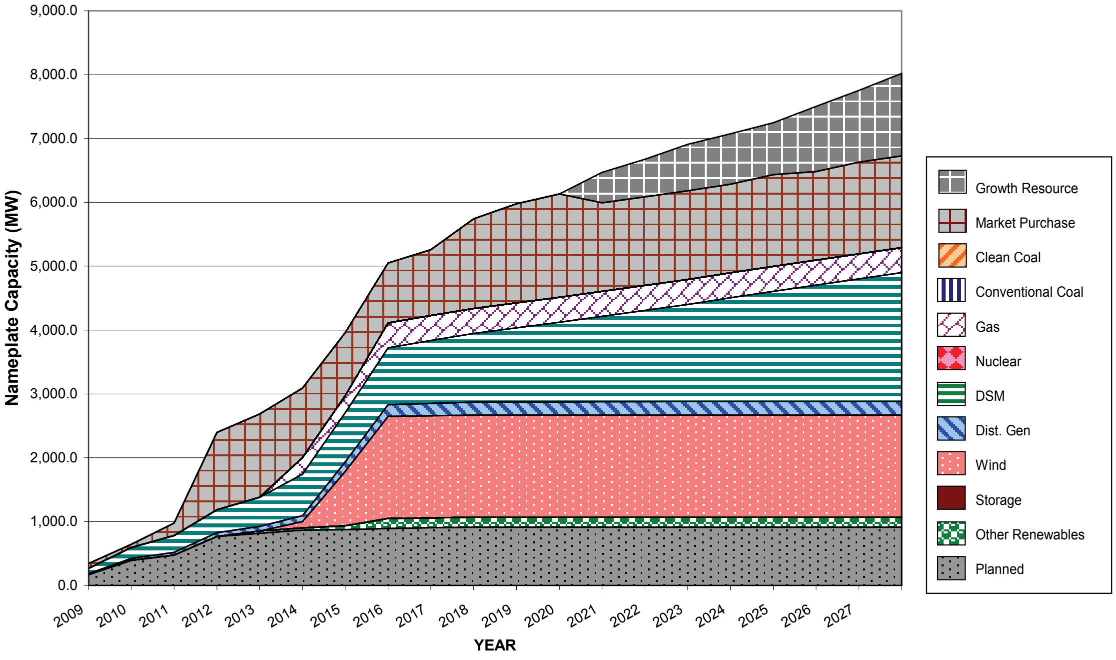
PVRR = $41,922



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 09b

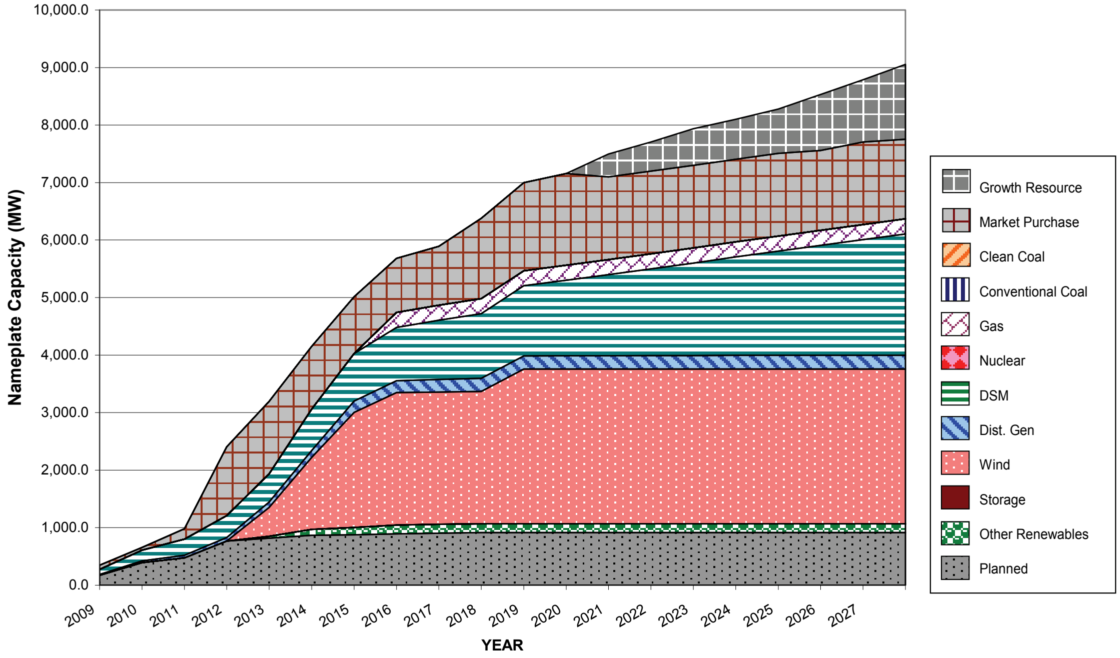
PVRR = $40,967



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 10b

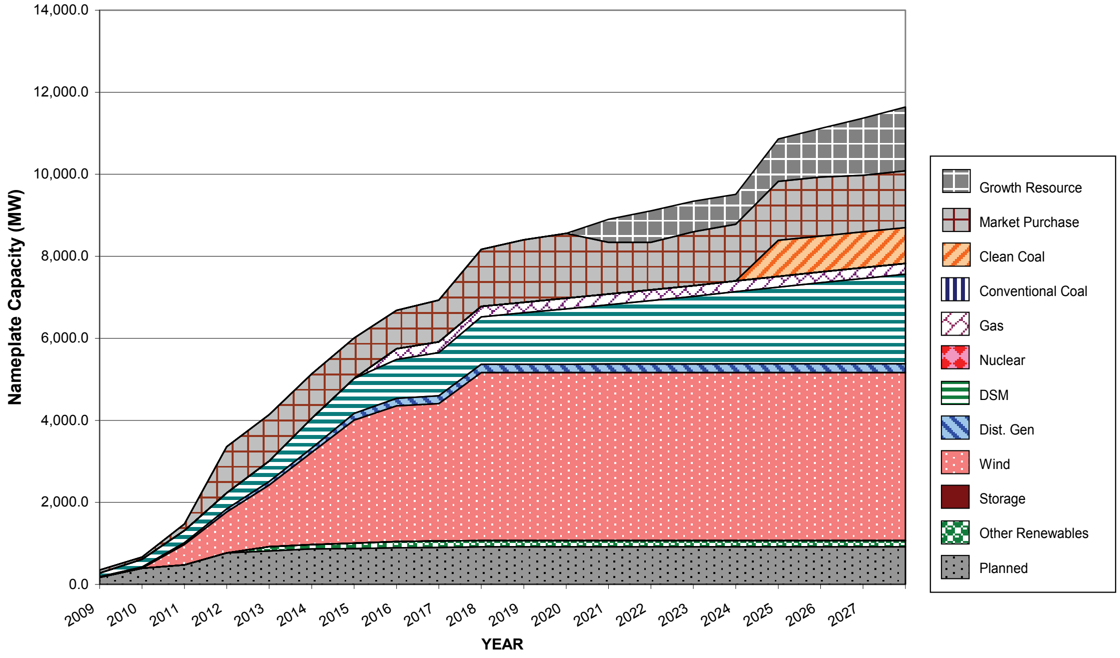
PVRR = $40,904



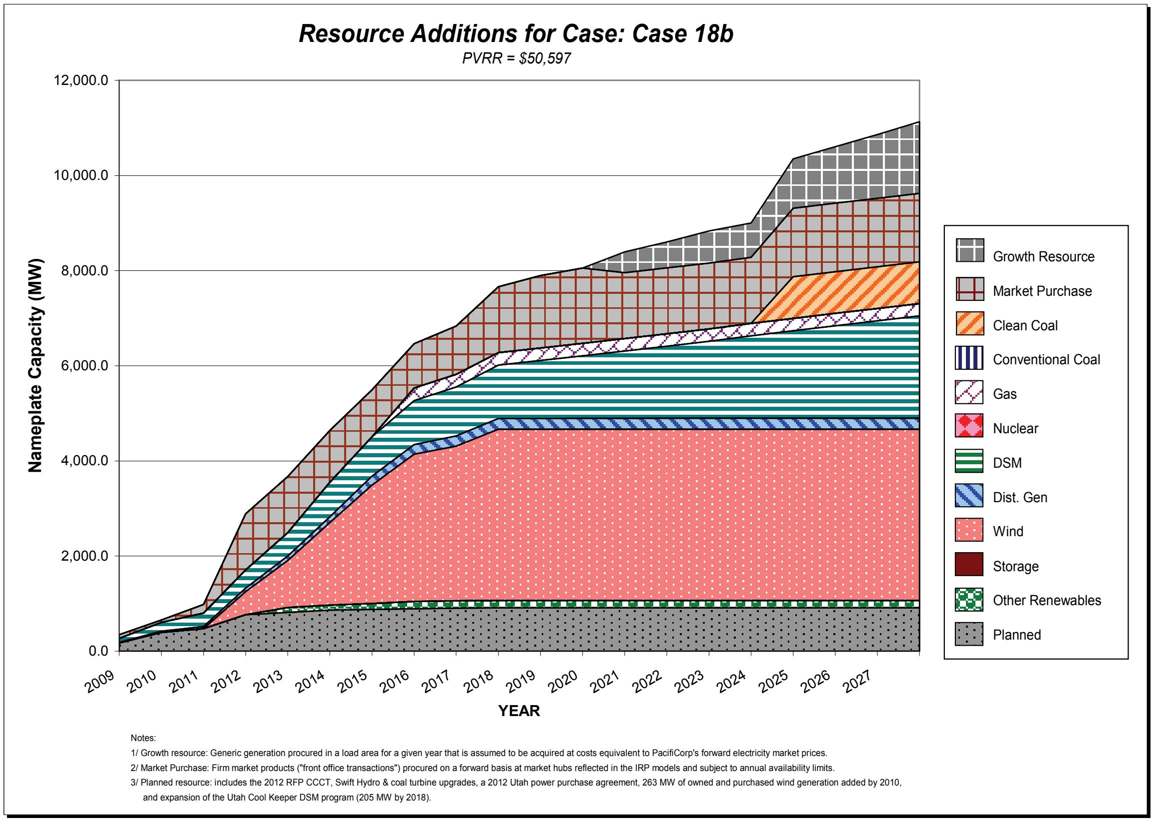
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

Resource Additions for Case: Case 17b

PVRR = $51,819



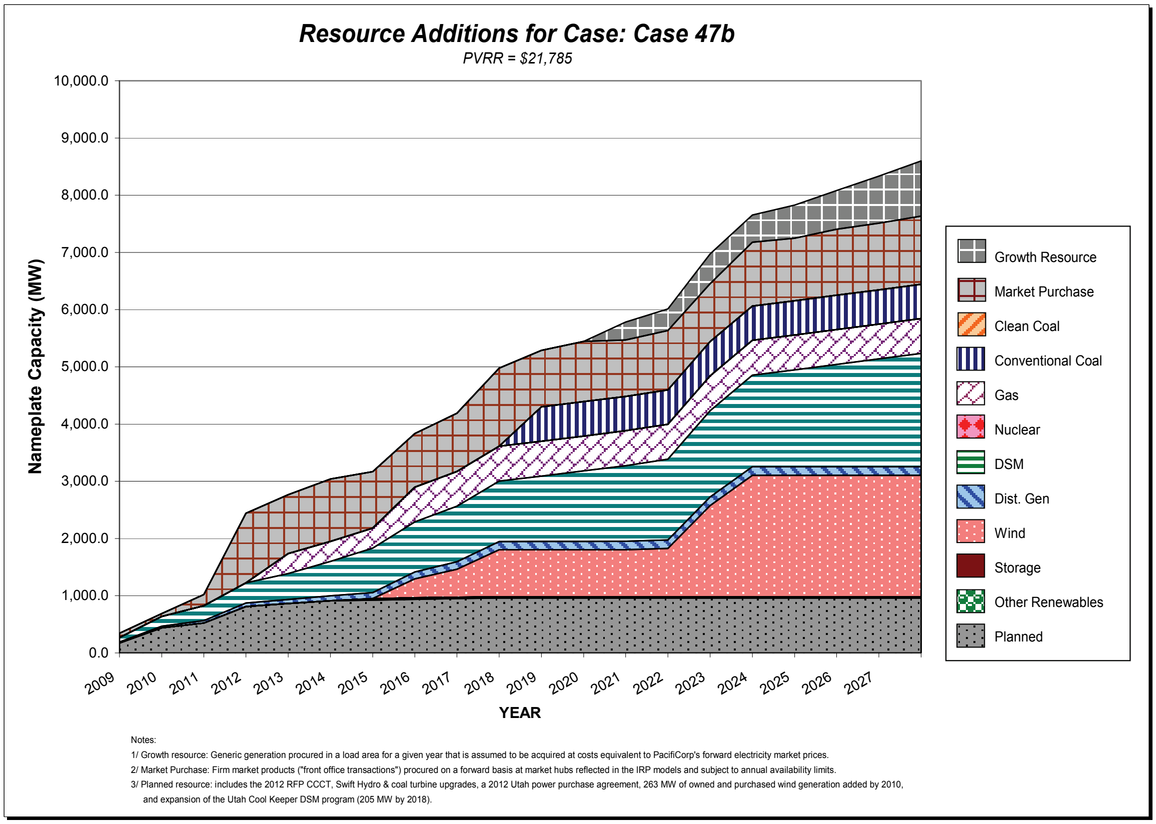
Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 18b

PVRR = $50,597

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).



Resource Additions for Case: Case 47b

PVRR = $21,785

Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

CORE CASES – PIVOT SUMMARY

Table A.4 – Pivot Summary Year 2009 to 2013 (Medium Load Growth Only)

Load	Medium													2009-2013
Sum of Capacity			Group											
Co2	Case (Price Curve)	Year	Wind	Other Renewables	Nuclear	Gas	Dist. Gen	DSM	SCPC	Clean Coal	Storage	Growth Resource	Market Purchase	Planned Resource
$0	Case 01 (Low - June 2008)	2009					13	9						172
		2010					13	44						222
		2011					13	72					301	82
		2012					13	75					801	899
		2013					13	89					933	49
	Case 01 (Low - June 2008) Total						67	289						1,423
	Case 02 (Medium - June 2008)	2009					8	78						172
		2010					8	87						222
		2011					8	88					219	82
		2012					8	90					714	899
		2013		35			8	93					817	49
	Case 02 (Medium - June 2008) Total			35			41	436						1,423
	Case 03 (High - June 2008)	2009					8	87						172
		2010	500				8	99						222
		2011	500				14	97					129	82
		2012	295				8	98					601	899
		2013		105			8	99					648	49
	Case 03 (High - June 2008) Total		1,295	105			47	480						1,423
$45	Case 05 (Low - June 2008)	2009					8	76						172
		2010					8	87						222
		2011					8	88					220	82
		2012					8	90					716	899
		2013		35			9	95					817	49
	Case 05 (Low - June 2008) Total			35			42	436						1,423
	Case 08 (Medium - June 2008)	2009					10	81						172
		2010					13	92						222
		2011					13	91					200	82
		2012	264				20	93					683	899
		2013	500	35			15	100					758	49
	Case 08 (Medium - June 2008) Total		764	35			72	458						1,423
	Case 09 (Low - Oct 2008)	2009					8	76						172
		2010					8	87						222
		2011					8	88					220	82
		2012					8	90					716	899
		2013		35			9	93					818	49
	Case 09 (Low - Oct 2008) Total			35			42	434						1,423
	Case 10 (Medium - Oct 2008)	2009					8	78						172
		2010					8	91						222
		2011					9	91					213	82
		2012					9	93					705	899
		2013	361	35			9	96					798	49
	Case 10 (Medium - Oct 2008) Total		361	35			44	450						1,423
	Case 11 (High - Oct 2008)	2009					8	86						172
		2010					8	99						222
		2011	64				8	97					196	82
		2012	500				14	99					674	899
		2013	500	105			8	103					663	49
	Case 11 (High - Oct 2008) Total		1,064	105			47	484						1,423
	Case 14 (High - June 2008)	2009					8	90						172
		2010	500				8	103						222
		2011	500				20	98					122	82
		2012	500				9	103					586	899
		2013	500	105			9	104					615	49
	Case 14 (High - June 2008) Total		2,000	105			55	499						1,423
$70	Case 17 (Medium - June 2008)	2009					8	82						172
		2010					8	98						222
		2011	194				9	97					197	82
		2012	500				21	99					673	899
		2013	500	105			9	99					688	49
	Case 17 (Medium - June 2008) Total		1,194	105			56	475						1,423
	Case 18 (Low - Oct 2008)	2009					8	78						172
		2010					9	91						222
		2011					9	91					213	82
		2012	263				21	93					699	899
		2013	500	70			9	100					745	49
	Case 18 (Low - Oct 2008) Total		763	70			57	454						1,423
	Case 19 (Medium - Oct 2008)	2009					8	81						172
		2010					9	92						222
		2011					9	96					207	82
		2012	500				21	98					682	899
		2013	500	105			9	101					695	49
	Case 19 (Medium - Oct 2008) Total		1,000	105			57	468						1,423
	Case 20 (High - Oct 2008)	2009					8	87						172
		2010					8	99						222
		2011	500				8	97					184	82
		2012	500				20	102					631	899
		2013	500	105			8	104					800	49
	Case 20 (High - Oct 2008) Total		1,500	105			53	490						1,423
	Case 22 (High - June 2008)	2009					8	90						172
		2010	500				8	103						222
		2011	500				14	98					122	82
		2012	500				14	103					591	899
		2013	500	105			9	105					605	49
	Case 22 (High - June 2008) Total		2,000	105			54	500						1,423

Load	Medium		2009-2013
Sum of Capacity		Group	

Co2	Case (Price Curve)	Year	Wind	Other Renewables	Nuclear	Gas	Dist. Gen	DSM	SCPC	Clean Coal	Storage	Growth Resource	Market Purchase	Planned Resource
$100	Case 24 (Medium - June 2008)	2009					9	87						172
		2010	489				9	99						222
		2011	500				9	98					128	82
		2012	500				21	103					596	899
		2013	500	105			9	104					607	49
	Case 24 (Medium - June 2008) Total		1,989	105			59	492						1,423
	Case 25 (Low - Oct 2008)	2009					9	82						172
		2010					9	98						222
		2011	500				9	97					185	82
		2012	500				21	102					661	899
		2013	500	105			9	104					800	49
	Case 25 (Low - Oct 2008) Total		1,500	105			59	483						1,423
	Case 26 (Medium - Oct 2008)	2009					9	87						172
		2010					9	99						222
		2011	500				9	97					182	82
		2012	500				21	103					643	899
		2013	500	105			9	104					800	49
	Case 26 (Medium - Oct 2008) Total		1,500	105			59	490						1,423
	Case 27 (High - Oct 2008)	2009					8	87						172
		2010	500				9	103						222
		2011	500				9	98					126	82
		2012	500				21	103					593	899
		2013	500	105			9	104					800	49
	Case 27 (High - Oct 2008) Total		2,000	105			57	496						1,423
	Case 29 (High - June 2008)	2009					9	91						172
		2010	500				14	109						222
		2011	500				20	106					102	82
		2012	500				21	109					556	899
		2013	500	105			15	110					564	49
	Case 29 (High - June 2008) Total		2,000	105			78	526						1,423

Table A.5 – Pivot Summary Year 2014 to 2020 (Medium Load Growth Only)

Load	Medium													**2014-2020**
Sum of Capacity			Group											
Co2	Case (Price Curve)	**Year**	**Wind**	**Other Renewables**	**Nuclear**	**Gas**	**Dist. Gen**	**DSM**	**SCPC**	**Clean Coal**	**Storage**	**Growth Resource**	**Market Purchase**	**Planned Resource**
$0	Case 01 (Low - June 2008)	2014					13	85					1,055	49
		2015					13	162					989	10
		2016				261	13	118					939	18
		2017					8	87					1,039	10
		2018					8	82					1,422	10
		2019					5	82					1,566	
		2020					0	82					1,638	
	Case 01 (Low - June 2008) Total					261	63	699						97
	Case 02 (Medium - June 2008)	2014					8	92					938	49
		2015					8	92					949	10
		2016				261	8	89					933	18
		2017					8	96					1,027	10
		2018	140				10	87	600				863	10
		2019	160				2	87					1,008	
		2020					3	88					1,074	
	Case 02 (Medium - June 2008) Total		300			261	48	630	600					97
	Case 03 (High - June 2008)	2014	135				14	102					749	49
		2015	750	25			8	102					709	10
		2016	223	25			8	101					891	18
		2017	138				8	104					967	10
		2018	750				8	99	790				604	10
		2019	712					97					739	
		2020						97					800	
	Case 03 (High - June 2008) Total		2,708	50			47	702	790					97
$45	Case 05 (Low - June 2008)	2014					9	94					935	49
		2015	300				11	95					936	10
		2016				261	11	95					914	18
		2017					11	97					1,004	10
		2018	750				11	87					1,365	10
		2019	400				3	87					1,500	
		2020					3	88					1,566	
	Case 05 (Low - June 2008) Total		1,450			261	59	642						97
	Case 08 (Medium - June 2008)	2014	286				15	101					859	49
		2015	750	25			22	101					821	10
		2016	193	60			16	107					939	18
		2017	158				11	104					1,010	10
		2018	249				11	92					1,358	10
		2019					3	96					1,500	
		2020					3	95					1,561	
	Case 08 (Medium - June 2008) Total		1,636	85			80	695						97
	Case 09 (Low - Oct 2008)	2014					9	94					937	49
		2015	300				11	95					938	10
		2016				261	11	95					916	18
		2017	444				11	97					996	10
		2018	536				11	87					1,362	10
		2019	305				3	87					1,499	
		2020	15				3	88					1,565	
	Case 09 (Low - Oct 2008) Total		1,600			261	58	642						97
	Case 10 (Medium - Oct 2008)	2014	291				9	101					902	49
		2015	750	25			25	102					867	10
		2016	591	95			16	107					939	18
		2017	158				11	104					1,010	10
		2018	248				11	92					1,358	10
		2019	200				3	96					1,468	
		2020					3	95					1,529	
	Case 10 (Medium - Oct 2008) Total		2,238	120			78	696						97
	Case 11 (High - Oct 2008)	2014	750				14	105					733	49
		2015	750	25			10	104					689	10
		2016	750	25			10	104					863	18
		2017	750				10	105					915	10
		2018	750				10	106	600				726	10
		2019	185				2	97					866	
		2020					2	97					925	
	Case 11 (High - Oct 2008) Total		3,935	50			60	718	600					97
	Case 14 (High - June 2008)	2014	750				9	105					689	49
		2015	750	25			11	104					651	10
		2016	750	25			11	105					790	18
		2017	482				11	106					866	10
		2018	622			0	11	106	600				679	10
		2019	335				3	98					819	
		2020	199				3	98					877	
	Case 14 (High - June 2008) Total		3,888	50		0	58	722	600					97

Load	Medium													2014-2020
Sum of Capacity			Group											
$70	Case 17 (Medium - June 2008)	2014	750				9	102					764	49
		2015	750	25			11	102					701	10
		2016	595	25			11	103					875	18
		2017	110				11	112					947	10
		2018	500				11	99					1,287	10
		2019					3	97					1,429	
		2020					3	97					1,487	
	Case 17 (Medium - June 2008) Total		2,706	50			59	713						97
	Case 18 (Low - Oct 2008)	2014	750	35			9	102					810	49
		2015	486	25			11	102					749	10
		2016	400	25			11	101					903	18
		2017	750				11	110					969	10
		2018	750				11	92					1,310	10
		2019					3	96					1,453	
		2020					2	95					1,514	
	Case 18 (Low - Oct 2008) Total		3,136	85			58	698						97
	Case 19 (Medium - Oct 2008)	2014	750				9	102					794	49
		2015	750	25			11	102					707	10
		2016	750	25			11	101					881	18
		2017	585				11	111					944	10
		2018	265				11	98					1,287	10
		2019					3	97					1,429	
		2020					2	97					1,488	
	Case 19 (Medium - Oct 2008) Total		3,100	50			58	708						97
	Case 20 (High - Oct 2008)	2014	750				9	105					720	49
		2015	750	25			10	104					685	10
		2016	750	25			10	104					855	18
		2017	750				10	112					914	10
		2018	750				10	99					1,228	10
		2019	750				2	97					1,368	
		2020	600				2	97					1,426	
	Case 20 (High - Oct 2008) Total		5,100	50			55	719						97
	Case 22 (High - June 2008)	2014	750				9	110					700	49
		2015	750	25			10	112					653	10
		2016	750	25			10	110					807	18
		2017	750				10	113					1,007	10
		2018	750				8	111	600				658	10
		2019	750					102					791	
		2020	700					102					843	
	Case 22 (High - June 2008) Total		5,200	50			47	760	600					97
$100	Case 24 (Medium - June 2008)	2014	750				9	105					706	49
		2015	750	25			11	104					673	10
		2016	750	25			11	104					841	18
		2017	750				11	105					883	10
		2018	750				11	106					1,218	10
		2019	750				2	102					1,355	
		2020	111				2	103					1,411	
	Case 24 (Medium - June 2008) Total		4,611	50			57	729						97
	Case 25 (Low - Oct 2008)	2014	750				9	105					850	49
		2015	750	25			11	104					850	10
		2016	750	25			11	104					1,015	18
		2017	750				11	112					1,530	10
		2018	750				11	99					1,530	10
		2019	750				2	97					1,530	
		2020	175				2	97					1,530	
	Case 25 (Low - Oct 2008) Total		4,675	50			57	719						97
	Case 26 (Medium - Oct 2008)	2014	750				9	105					728	49
		2015	750	25			11	104					800	10
		2016	750	25			11	104					1,009	18
		2017	750				11	112					1,072	10
		2018	750				11	99					1,381	10
		2019	750				2	97					1,423	
		2020	600				2	97					1,482	
	Case 26 (Medium - Oct 2008) Total		5,100	50			57	719						97
	Case 27 (High - Oct 2008)	2014	750				9	110					800	49
		2015	750	25			11	112					800	10
		2016	750	25			11	109					987	18
		2017	750				11	114					1,019	10
		2018	750				11	111					1,352	10
		2019	750				3	103					1,390	
		2020	180				2	103					1,443	
	Case 27 (High - Oct 2008) Total		4,680	50			58	763						97
	Case 29 (High - June 2008)	2014	750				15	112					661	49
		2015	750	25			16	113					716	10
		2016	750	25			16	110					926	18
		2017	750				16	218					850	10
		2018	750				16	110					1,009	10
		2019	750				2	103					1,144	
		2020	700				2	103					1,197	
	Case 29 (High - June 2008) Total		5,200	50			84	870						97

Table A.6 – Pivot Summary Year 2021 to 2028 (Medium Load Growth Only)

Load	Medium													2021-2028
Sum of Capacity			Group											
Co2	Case (Price Curve)	Year	Wind	Other Renewables	Nuclear	Gas	Dist. Gen	DSM	SCPC	Clean Coal	Storage	Growth Resource	Market Purchase	Planned Resource
$0	Case 01 (Low - June 2008)	2021						76				407	1,388	
		2022						79				531	1,388	
		2023						80				629	1,438	
		2024						79				708	1,438	
		2025						81				889	1,438	
		2026						88				1,051	1,438	
		2027						89				1,213	1,438	
		2028						85				1,441	1,388	
	Case 01 (Low - June 2008) Total							657						
	Case 02 (Medium - June 200	2021					3	90				268	950	
		2022					3	91				363	966	
		2023	14				3	93				287	1,177	
		2024					3	93				535	995	
		2025					3	92				633	1,068	
		2026					3	95				668	1,188	
		2027	628				3	98				636	1,359	
		2028					1	97				804	1,361	
	Case 02 (Medium - June 2008) Total		641				20	750						
	Case 03 (High - June 2008)	2021						98				450	491	
		2022						99				440	608	
		2023						101				299	881	
		2024						116				289	942	
		2025						107				664	728	
		2026						98				713	834	
		2027						100				198	1,504	
		2028						98				438	1,433	
	Case 03 (High - June 2008) Total							817						
$45	Case 05 (Low - June 2008)	2021	150				3	90				399	1,308	
		2022					3	91				430	1,389	
		2023					2	93				578	1,377	
		2024					2	93				693	1,329	
		2025						100		346		719	1,588	
		2026						97				875	1,588	
		2027						98				981	1,638	
		2028						97				1,200	1,588	
	Case 05 (Low - June 2008) Total		150				9	760		346				
	Case 08 (Medium - June 200	2021					3	95				495	1,206	
		2022					2	97				250	1,558	
		2023					2	100				352	1,588	
		2024					2	105				545	1,453	
		2025						102				575	1,588	
		2026						98				731	1,588	
		2027						100				885	1,588	
		2028						98				1,161	1,543	
	Case 08 (Medium - June 2008) Total						8	797						
	Case 09 (Low - Oct 2008)	2021					3	90				121	1,588	
		2022					3	91				233	1,588	
		2023					2	93				369	1,588	
		2024					2	93				435	1,588	
		2025						100		346		720	1,588	
		2026						97				877	1,588	
		2027						98				1,032	1,588	
		2028						97				1,202	1,588	
	Case 09 (Low - Oct 2008) Total						10	760		346				
	Case 10 (Medium - Oct 2008	2021					2	95				95	1,574	
		2022					2	97				190	1,588	
		2023					2	100				321	1,588	
		2024					2	105				379	1,588	
		2025						102				544	1,588	
		2026						98				700	1,588	
		2027						100				854	1,588	
		2028						98				1,023	1,588	
	Case 10 (Medium - Oct 2008) Total						7	797						
	Case 11 (High - Oct 2008)	2021					2	99				285	778	
		2022					2	100				306	862	
		2023					2	102				321	977	
		2024						117				186	1,162	
		2025						108				288	1,283	
		2026						106				706	1,015	
		2027						100				1,130	850	
		2028						98				1,984	168	
	Case 11 (High - Oct 2008) Total						6	828						
	Case 14 (High - June 2008)	2021	398				3	105				224	785	
		2022					2	106				235	875	
		2023					2	102				724	515	
		2024						117				261	1,029	
		2025						108		466		181	853	
		2026						106				199	984	
		2027						104				151	1,184	
		2028						104				200	1,300	
	Case 14 (High - June 2008) Total		398				7	852		466				

Load	Medium													**2021-2028**
Sum of Capacity			Group											
Co2	Case (Price Curve)	**Year**	**Wind**	**Other Renewables**	**Nuclear**	**Gas**	**Dist. Gen**	**DSM**	**SCPC**	**Clean Coal**	**Storage**	**Growth Resource**	**Market Purchase**	**Planned Resource**
$70	Case 17 (Medium - June 20	2021					2	99				107	1,518	
		2022					2	100				144	1,588	
		2023					2	102				274	1,588	
		2024					2	117				323	1,588	
		2025						108		876		778	1,588	
		2026						106				927	1,588	
		2027						104				1,078	1,588	
		2028						104				1,243	1,588	
	Case 17 (Medium - June 2008) Total						7	840		876				
	Case 18 (Low - Oct 2008)	2021					2	95				186	1,468	
		2022					2	97				310	1,452	
		2023					2	101				305	1,588	
		2024					2	116				474	1,468	
		2025						107		876		810	1,588	
		2026						106				960	1,588	
		2027						103				1,062	1,638	
		2028						103				1,227	1,638	
	Case 18 (Low - Oct 2008) Total						7	829		876				
	Case 19 (Medium - Oct 2008	2021					2	99				94	1,532	
		2022					2	100				144	1,588	
		2023					2	102				290	1,572	
		2024					2	117				368	1,543	
		2025						108		876		779	1,588	
		2026						106				928	1,588	
		2027						104				1,079	1,650	
		2028						104				1,194	1,700	
	Case 19 (Medium - Oct 2008) Total						7	840		876				
	Case 20 (High - Oct 2008)	2021					2	99				826	800	
		2022					2	100				743	989	
		2023					2	102				716	1,146	
		2024						117				431	1,481	
		2025			1,600			108		876			939	
		2026						106				11	1,077	
		2027						104				464	800	
		2028						98				2,014	800	
	Case 20 (High - Oct 2008) Total				1,600		6	833		876				
	Case 22 (High - June 2008)	2021						105				154	824	
		2022						106				173	908	
		2023						108				179	1,029	
		2024						117				242	1,016	
		2025			1,600			109		876		123	161	
		2026						107				125	308	
		2027						104				124	639	
		2028						106				165	654	
	Case 22 (High - June 2008) Total				1,600			862		876				
$100	Case 24 (Medium - June 20	2021					2	105				211	1,333	
		2022					2	106				357	1,289	
		2023					2	108				517	1,254	
		2024					2	118				815	1,005	
		2025			3,200			109		876		163	565	
		2026						107				62	683	
		2027						104				34	745	
		2028						106				82	753	
	Case 24 (Medium - June 2008) Total				3,200		6	862		876				
	Case 25 (Low - Oct 2008)	2021					2	99				96	1,530	
		2022					2	100				402	1,268	
		2023					2	102				332	1,530	
		2024					2	117				499	1,349	
		2025						108		876		836	1,468	
		2026						106				1,186	1,268	
		2027						104				1,087	1,518	
		2028						104				1,776	993	
	Case 25 (Low - Oct 2008) Total						6	840		876				
	Case 26 (Medium - Oct 2008	2021					2	99				613	1,063	
		2022					2	100				570	1,094	
		2023					2	102				676	1,117	
		2024					2	117				502	1,341	
		2025			3,200			108		876			731	
		2026						106				11	257	
		2027						104				35	268	
		2028						104				82	277	
	Case 26 (Medium - Oct 2008) Total				3,200		6	840		876				
	Case 27 (High - Oct 2008)	2021					2	105				245	1,330	
		2022					2	107				482	1,194	
		2023					2	108				435	1,366	
		2024						117				374	1,477	
		2025			3,200			108		876			1,280	
		2026						106				930	1,480	
		2027						99				431	1,480	
		2028						97				2,304	517	
	Case 27 (High - Oct 2008) Total				3,200		5	846		876				
	Case 29 (High - June 2008)	2021					2	106				601	728	
		2022					2	107				695	736	
		2023					2	110				809	745	
		2024						135				878	713	
		2025			3,200			110		1,342		140	81	
		2026						112				137	501	
		2027						112				148	125	
		2028						107				187	141	
	Case 29 (High - June 2008) Total				3,200		5	898		1,342				

Core Cases – 20-Year Summary by Scenario Variable

This section provides the 47 core cases 20-Year summarization for Load Growth, CO2 Tax Levels and Natural Gas Forward Price Curves. Additionally a Minimum and Maximum value for each resource group is provide at the bottom.

Table A.7 – 20-year Summary by Scenario Variable, Load Growth

Sum of 20 Year (MW)				Resource Group												
Load	CASE	Gas	CO2	SCPC	IGCC CCS	SCPC CCS	Gas	Dist. Gen	Other Renewables	Wind	Storage	Nuclear	Mkt Purchases	Planned Resource	DSM 1	DSM 2
Low	Case 04	Low - June 2008	$45			346		110	35	300			394	1,520		1,801
	Case 07	Medium - June 2008	$45			346		110	85	1,800			300	1,520		1,857
	Case 13	High - June 2008	$45	600				95	155	4,800			152	1,520		2,038
	Case 16	High - June 2008	$70			876		122	155	3,599			219	1,520		1,990
	Case 21	High - June 2008	$70			876		95	155	6,202		1,600	194	1,520		2,058
	Case 23	Medium - June 2008	$100			876		122	155	6,600		3,200	242	1,520		2,045
	Case 28	High - June 2008	$100			876		95	155	5,800		3,200	217	1,520		2,036
Medium	Case 01	Low - June 2008	$0				261	130					1,960	1,520	108	1,537
	Case 02	Medium - June 2008	$0	600			261	109	35	941			1,405	1,520	2	1,815
	Case 03	High - June 2008	$0	790				95	155	4,003			1,150	1,520	7	1,992
	Case 05	Low - June 2008	$45			346	261	110	35	1,600			1,823	1,520	2	1,835
	Case 08	Medium - June 2008	$45					160	120	2,400			1,714	1,520	7	1,942
	Case 09	Low - Oct 2008	$45			346	261	110	35	1,600			1,757	1,520	2	1,834
	Case 10	Medium - Oct 2008	$45					129	155	2,600			1,637	1,520	7	1,936
	Case 11	High - Oct 2008	$45	600				114	155	5,000			1,368	1,520	7	2,024
	Case 14	High - June 2008	$45	600	466			120	155	6,287			983	1,520	7	2,066
	Case 17	Medium - June 2008	$70			876		122	155	3,900			1,693	1,520	7	2,020
	Case 18	Low - Oct 2008	$70			876		122	155	3,900			1,756	1,520	7	1,974
	Case 19	Medium - Oct 2008	$70			876		122	155	4,100			1,703	1,520	7	2,009
	Case 20	High - Oct 2008	$70			876		114	155	6,600		1,600	1,493	1,520	7	2,035
	Case 22	High - June 2008	$70	600		876		101	155	7,200		1,600	776	1,520	7	2,115
	Case 24	Medium - June 2008	$100			876		122	155	6,600		3,200	1,082	1,520	7	2,076
	Case 25	Low - Oct 2008	$100			876		122	155	6,175			1,847	1,520	7	2,035
	Case 26	Medium - Oct 2008	$100			876		122	155	6,600		3,200	1,095	1,520	7	2,042
	Case 27	High - Oct 2008	$100			876		120	155	6,680		3,200	1,622	1,520	7	2,098
	Case 29	High - June 2008	$100		466	876		167	155	7,200		3,200	1,024	1,520	110	2,183
	Case 46	Medium - Oct 2008	Cap-and-Trade	600			174	151		1,388			1,365	1,520	19	1,825
	Case 47	Medium - Oct 2008	Cap-and-Trade	600			174	151		1,344			1,361	1,520	29	1,822
High	Case 06	Low - June 2008	$45				1,838	209	155	1,600			2,306	1,520	126	1,983
	Case 12	Medium - June 2008	$45	600			888	169	155	2,299	805		2,311	1,520	126	2,082
	Case 15	High - June 2008	$45	600	466		261	169	655	6,599		1,600	1,719	1,520	125	2,163
			Min	600	466	346	174	95	35	300	805	1,600	152	1,520	2	1,537
			Max	790	466	876	1,838	209	655	7,200	805	3,200	2,311	1,520	126	2,183

Table A.8 – 20-year Summary by Scenario Variable, CO_2 level

Sum of 20 Year (MW)				Resource Group												
CO2	CASE	Load	Gas	**SCPC**	**SCPC CCS**	**IGCC CCS**	**Gas**	**Dist. Gen**	**Wind**	**Other Renewables**	**Storage**	**Nuclear**	**Mkt Purchases**	**Planned Resource**	**DSM 1**	**DSM 2**
$0	Case 01	Medium	Low - June 2008				261	130					1,960	1,520	108	1,537
	Case 02	Medium	Medium - June 2008	600			261	109	941	35			1,405	1,520	2	1,815
	Case 03	Medium	High - June 2008	790				95	4,003	155			1,150	1,520	7	1,992
$45	Case 04	Low	Low - June 2008		346			110	300	35			394	1,520		1,801
	Case 05	Medium	Low - June 2008		346		261	110	1,600	35			1,823	1,520	2	1,835
	Case 06	High	Low - June 2008				1,838	209	1,600	155			2,306	1,520	126	1,983
	Case 07	Low	Medium - June 2008		346			110	1,800	85			300	1,520		1,857
	Case 08	Medium	Medium - June 2008					160	2,400	120			1,714	1,520	7	1,942
	Case 09	Medium	Low - Oct 2008		346		261	110	1,600	35			1,757	1,520	2	1,834
	Case 10	Medium	Medium - Oct 2008					129	2,600	155			1,637	1,520	7	1,936
	Case 11	Medium	High - Oct 2008	600				114	5,000	155			1,368	1,520	7	2,024
	Case 12	High	Medium - June 2008	600			888	169	2,299	155	805		2,311	1,520	126	2,082
	Case 13	Low	High - June 2008	600				95	4,800	155			152	1,520		2,038
	Case 14	Medium	High - June 2008	600		466		120	6,287	155			983	1,520	7	2,066
	Case 15	High	High - June 2008	600		466	261	169	6,599	655		1,600	1,719	1,520	125	2,163
$70	Case 16	Low	High - June 2008		876			122	3,599	155			219	1,520		1,990
	Case 17	Medium	Medium - June 2008		876			122	3,900	155			1,693	1,520	7	2,020
	Case 18	Medium	Low - Oct 2008		876			122	3,900	155			1,756	1,520	7	1,974
	Case 19	Medium	Medium - Oct 2008		876			122	4,100	155			1,703	1,520	7	2,009
	Case 20	Medium	High - Oct 2008		876			114	6,600	155		1,600	1,493	1,520	7	2,035
	Case 21	Low	High - June 2008		876			95	6,202	155		1,600	194	1,520		2,058
	Case 22	Medium	High - June 2008	600	876			101	7,200	155		1,600	776	1,520	7	2,115
$100	Case 23	Low	Medium - June 2008		876			122	6,600	155		3,200	242	1,520		2,045
	Case 24	Medium	Medium - June 2008		876			122	6,600	155		3,200	1,082	1,520	7	2,076
	Case 25	Medium	Low - Oct 2008		876			122	6,175	155			1,847	1,520	7	2,035
	Case 26	Medium	Medium - Oct 2008		876			122	6,600	155		3,200	1,095	1,520	7	2,042
	Case 27	Medium	High - Oct 2008		876			120	6,680	155		3,200	1,622	1,520	7	2,098
	Case 28	Low	High - June 2008		876			95	5,800	155		3,200	217	1,520		2,036
	Case 29	Medium	High - June 2008		876	466		167	7,200	155		3,200	1,024	1,520	110	2,183
Cap-and-Trade	Case 46	Medium	Medium - Oct 2008	600			174	151	1,388				1,365	1,520	19	1,825
	Case 47	Medium	Medium - Oct 2008	600			174	151	1,344				1,361	1,520	29	1,822
			Min	600	346	466	174	95	300	35	805	1,600	152	1,520	2	1,537
			Max	790	876	466	1,838	209	7,200	655	805	3,200	2,311	1,520	126	2,183

Table A.9 – 20-year Summary by Scenario Variable, Natural Gas Price Forecast

Sum of 20 Year (MW)				Resource Group												
Gas	CASE	Load	CO2	**SCPC**	**SCPC CCS**	**IGCC CCS**	**Gas**	**Dist. Gen**	**Other Renewables**	**Wind**	**Storage**	**Nuclear**	**Mkt Purchases**	**Planned Resource**	**DSM 1**	**DSM 2**
Low - June 2008	Case 01	Medium	$0				261	130					1,960	1,520	108	1,537
	Case 04	Low	$45		346			110	35	300			394	1,520		1,801
	Case 05	Medium	$45		346		261	110	35	1,600			1,823	1,520	2	1,835
	Case 06	High	$45				1,838	209	155	1,600			2,306	1,520	126	1,983
Medium - June 2008	Case 02	Medium	$0	600			261	109	35	941			1,405	1,520	2	1,815
	Case 07	Low	$45		346			110	85	1,800			300	1,520		1,857
	Case 08	Medium	$45					160	120	2,400			1,714	1,520	7	1,942
	Case 12	High	$45	600			888	169	155	2,299	805		2,311	1,520	126	2,082
	Case 17	Medium	$70		876			122	155	3,900			1,693	1,520	7	2,020
	Case 23	Low	$100		876			122	155	6,600		3,200	242	1,520		2,045
	Case 24	Medium	$100		876			122	155	6,600		3,200	1,082	1,520	7	2,076
High - June 2008	Case 03	Medium	$0	790				95	155	4,003			1,150	1,520	7	1,992
	Case 13	Low	$45	600				95	155	4,800			152	1,520		2,038
	Case 14	Medium	$45	600		466		120	155	6,287			983	1,520	7	2,066
	Case 15	High	$45	600		466	261	169	655	6,599		1,600	1,719	1,520	125	2,163
	Case 16	Low	$70		876			122	155	3,599			219	1,520		1,990
	Case 21	Low	$70		876			95	155	6,202		1,600	194	1,520		2,058
	Case 22	Medium	$70	600	876			101	155	7,200		1,600	776	1,520	7	2,115
	Case 28	Low	$100		876			95	155	5,800		3,200	217	1,520		2,036
	Case 29	Medium	$100		876	466		167	155	7,200		3,200	1,024	1,520	110	2,183
Low - Oct 2008	Case 09	Medium	$45		346		261	110	35	1,600			1,757	1,520	2	1,834
	Case 18	Medium	$70		876			122	155	3,900			1,756	1,520	7	1,974
	Case 25	Medium	$100		876			122	155	6,175			1,847	1,520	7	2,035
Medium - Oct 2008	Case 10	Medium	$45					129	155	2,600			1,637	1,520	7	1,936
	Case 19	Medium	$70		876			122	155	4,100			1,703	1,520	7	2,009
	Case 26	Medium	$100		876			122	155	6,600		3,200	1,095	1,520	7	2,042
	Case 46	Medium	Cap-and-Trade	600			174	151		1,388			1,365	1,520	19	1,825
	Case 47	Medium	Cap-and-Trade	600			174	151		1,344			1,361	1,520	29	1,822
High - Oct 2008	Case 11	Medium	$45	600				114	155	5,000			1,368	1,520	7	2,024
	Case 20	Medium	$70		876			114	155	6,600		1,600	1,493	1,520	7	2,035
	Case 27	Medium	$100		876			120	155	6,680		3,200	1,622	1,520	7	2,098
			Min	600	346	466	174	95	35	300	805	1,600	152	1,520	2	1,537
			Max	790	876	466	1,838	209	655	7,200	805	3,200	2,311	1,520	126	2,183

Resource Type Summary

In the following tables, resource additions are reported at capacity megawatts accrued as of the year listed.

Table A.10 – Total Aggregate Capacity Additions for 20 years

Aggregate Resource Additions

(Capacity MW) (Does not include Short Term Resources)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	195	474	641	1,628	1,780	1,927	2,113	2,524	2,629	2,730	2,817	2,900	2,976	3,055	3,134	3,213	3,294	3,382	3,471	3,556
Case 02	258	575	753	1,751	1,935	2,085	2,195	2,572	2,685	3,532	3,781	3,872	3,964	4,058	4,168	4,264	4,358	4,456	5,185	5,283
Case 03	267	1,096	1,789	3,090	3,351	3,651	4,546	4,922	5,182	6,840	7,648	7,745	7,842	7,942	8,043	8,159	8,266	8,365	8,464	8,562
Case 04	253	569	746	1,744	1,926	2,076	2,328	2,446	2,721	2,828	2,917	3,007	3,100	3,194	3,290	3,386	3,824	3,920	4,016	4,111
Case 05	256	573	750	1,748	1,935	2,088	2,503	2,888	3,005	3,864	4,353	4,444	4,686	4,780	4,875	4,970	5,417	5,513	5,612	5,709
Case 06	266	593	781	2,052	2,266	2,772	3,711	4,257	4,380	5,216	5,314	5,886	6,687	6,788	6,890	7,008	7,115	7,221	7,325	7,429
Case 07	261	581	762	1,790	2,476	2,975	3,865	3,988	4,207	4,416	4,506	4,597	4,695	4,794	4,890	4,987	5,081	5,177	5,274	5,718
Case 08	263	590	777	2,053	2,751	3,201	4,109	4,503	4,786	5,147	5,247	5,344	5,442	5,542	5,643	5,750	5,851	5,950	6,050	6,148
Case 09	256	573	751	1,749	1,934	2,086	2,501	2,885	3,447	4,092	4,486	4,591	4,684	4,778	4,873	4,969	5,415	5,512	5,610	5,707
Case 10	259	579	761	1,763	2,314	2,764	3,676	4,502	4,785	5,147	5,446	5,543	5,641	5,740	5,841	5,948	6,050	6,148	6,248	6,346
Case 11	267	595	847	2,359	3,123	4,041	4,941	5,848	6,724	8,200	8,485	8,584	8,685	8,787	8,891	9,008	9,116	9,221	9,321	9,419
Case 12	271	604	797	2,263	3,295	3,883	5,298	5,478	5,604	6,323	6,558	6,828	7,049	7,156	7,266	7,400	7,509	8,026	8,523	8,643
Case 13	267	1,096	1,790	3,305	4,070	4,982	5,879	6,295	6,642	7,983	8,105	8,203	8,467	8,567	8,669	8,786	8,894	9,000	9,104	9,207
Case 14	271	1,104	1,804	3,315	4,081	4,994	5,895	6,803	7,413	8,762	9,198	9,497	10,003	10,111	10,215	10,333	10,906	11,013	11,117	11,221
Case 15	281	1,125	1,840	3,362	4,147	5,330	6,500	7,773	8,657	10,132	10,987	11,209	11,316	11,425	11,534	11,669	13,844	13,950	14,054	14,158
Case 16	262	583	869	2,387	3,149	4,059	4,957	5,496	5,829	6,345	6,444	6,541	6,640	6,742	6,845	6,964	7,947	8,054	8,158	8,262
Case 17	262	589	971	2,490	3,252	4,163	5,061	5,813	6,057	6,677	6,777	6,877	6,978	7,079	7,183	7,301	8,285	8,391	8,496	8,599
Case 18	259	580	762	2,039	2,767	3,712	4,346	4,902	5,782	6,646	6,745	6,841	6,939	7,038	7,140	7,258	8,241	8,347	8,450	8,553
Case 19	262	583	770	2,289	3,053	3,963	4,861	5,767	6,483	6,867	6,966	7,066	7,167	7,269	7,372	7,490	8,474	8,581	8,685	8,789
Case 20	267	596	1,284	2,805	3,571	4,484	5,384	6,291	7,173	8,043	8,892	9,591	9,692	9,794	9,898	10,015	12,599	12,705	12,809	12,907
Case 21	271	1,104	1,798	3,314	4,080	4,992	5,890	6,795	7,669	8,536	9,086	9,184	9,284	9,384	9,486	9,604	12,188	12,295	12,399	12,505
Case 22	271	1,104	1,799	3,315	4,082	5,000	5,907	6,820	7,703	9,181	10,034	10,836	10,941	11,046	11,155	11,272	13,857	13,964	14,068	14,174
Case 23	267	905	1,594	3,117	3,884	4,797	5,697	6,604	7,480	8,350	9,200	9,591	9,692	9,794	9,897	10,016	14,201	14,307	14,412	14,517
Case 24	268	1,087	1,776	3,300	4,067	4,980	5,880	6,788	7,664	8,541	9,396	9,611	9,717	9,825	9,935	10,054	14,238	14,345	14,450	14,556
Case 25	262	592	1,280	2,803	3,570	4,483	5,383	6,291	7,174	8,044	8,893	9,167	9,268	9,369	9,472	9,591	10,575	10,681	10,786	10,889
Case 26	267	598	1,286	2,810	3,576	4,490	5,390	6,298	7,181	8,051	8,900	9,599	9,699	9,801	9,904	10,023	14,207	14,313	14,417	14,521
Case 27	267	1,101	1,790	3,314	4,081	4,999	5,907	6,821	7,705	8,587	9,443	9,729	9,836	9,944	10,054	10,171	14,354	14,460	14,560	14,656
Case 28	271	1,104	1,799	3,315	4,081	4,993	5,891	6,796	7,670	8,537	8,685	8,783	8,882	8,983	9,085	9,202	13,381	13,480	13,581	13,682
Case 29	272	1,116	1,825	3,353	4,132	5,057	5,971	6,891	7,885	8,771	9,627	10,432	10,539	10,648	10,759	10,894	15,545	15,658	15,770	15,877
Case 30	267	595	784	1,941	2,644	3,599	4,499	5,442	6,324	7,194	8,045	8,900	9,757	10,215	10,325	10,460	15,110	15,217	15,329	15,436
Case 31	272	1,106	1,815	3,331	4,104	5,024	5,932	6,847	7,731	8,614	9,469	10,274	10,382	10,491	10,602	10,738	14,924	15,031	15,135	15,238
Case 33	282	1,127	1,837	3,409	4,442	5,644	6,617	8,118	9,018	10,499	11,182	11,948	12,812	12,928	13,046	13,185	13,309	13,835	14,341	14,452
Case 34	262	583	1,121	2,592	3,284	4,198	4,595	4,762	5,020	5,883	6,698	6,795	6,894	6,993	7,095	7,202	7,304	7,402	7,502	7,600
Case 35	271	1,105	1,806	3,316	4,047	4,959	5,856	6,759	7,209	8,358	8,455	8,552	8,651	8,751	8,852	8,968	9,070	9,168	9,268	9,365
Case 36	266	595	788	2,314	3,052	3,970	4,871	5,784	6,544	6,995	7,105	8,194	8,294	8,396	8,499	8,618	8,726	8,832	8,936	9,040
Case 37	271	1,104	1,798	3,314	4,046	4,958	5,856	6,763	7,637	8,511	8,622	12,796	12,895	12,996	13,098	13,215	13,324	13,431	13,535	13,641
Case 38	267	594	785	1,796	2,203	2,369	2,822	3,236	3,517	4,380	4,993	5,090	5,188	5,288	5,389	5,496	5,598	5,703	5,807	5,909
Case 39	276	893	1,593	3,108	3,845	4,372	5,275	5,545	5,722	6,692	6,790	6,888	6,992	7,116	7,224	7,358	7,469	7,584	7,699	7,865
Case 40	266	591	777	1,782	1,974	2,133	2,417	2,864	3,138	3,994	4,831	5,127	5,217	5,314	5,412	5,516	6,228	6,325	6,690	6,788
Case 41	267	593	781	2,104	2,874	3,421	4,338	4,762	4,886	4,999	5,098	5,195	5,293	5,392	5,494	5,600	5,702	5,800	5,900	5,999
Case 42	262	589	1,120	2,639	3,402	4,312	5,209	6,081	6,257	6,628	6,728	6,828	6,929	7,031	7,134	7,252	8,236	8,342	8,447	8,550
Case 43	277	1,116	1,811	3,340	4,112	5,036	5,949	6,973	7,849	8,720	9,574	9,778	9,884	9,991	10,101	10,221	14,405	14,512	14,617	14,722
Case 44	263	585	768	1,771	1,927	2,085	2,266	2,862	3,637	5,091	5,749	6,620	6,823	7,035	7,428	8,274	9,153	9,430	9,736	10,017
Case 45	251	560	958	2,455	2,605	2,754	2,867	3,280	3,397	4,104	4,195	4,287	4,380	4,474	4,765	4,861	4,978	5,099	5,195	5,289
Case 46	263	586	969	1,973	2,301	2,599	2,881	3,130	3,247	3,356	4,345	4,435	4,528	4,622	5,161	5,301	5,394	5,489	5,585	5,679
Case 47	263	585	768	1,771	2,101	2,259	2,381	2,871	3,145	3,585	4,274	4,388	4,504	4,626	5,115	5,263	5,356	5,451	5,547	5,640
Case 48	270	596	780	2,068	2,760	3,259	4,156	4,505	4,789	5,177	5,276	5,374	5,472	5,572	5,674	5,781	5,882	5,981	6,081	6,179

Table A.11 – Total Wind Aggregate Capacity Additions for 20 years

Wind

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	144	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263
Case 02	144	263	263	263	263	263	263	263	263	403	563	563	563	563	576	576	576	576	1,204	1,204
Case 03	144	763	1,263	1,558	1,558	1,693	2,443	2,666	2,804	3,554	4,266	4,266	4,266	4,266	4,266	4,266	4,266	4,266	4,266	4,266
Case 04	144	263	263	263	263	263	403	403	563	563	563	563	563	563	563	563	563	563	563	563
Case 05	144	263	263	263	263	263	563	563	563	1,313	1,713	1,713	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
Case 06	144	263	263	263	263	403	563	916	916	1,167	1,167	1,167	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
Case 07	144	263	263	290	790	1,136	1,886	1,886	1,963	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063	2,063
Case 08	144	263	263	527	1,027	1,313	2,063	2,256	2,414	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663
Case 09	144	263	263	263	263	263	563	563	1,007	1,543	1,848	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
Case 10	144	263	263	263	624	915	1,665	2,256	2,414	2,663	2,863	2,863	2,863	2,863	2,863	2,863	2,863	2,863	2,863	2,863
Case 11	144	263	327	827	1,327	2,077	2,827	3,577	4,327	5,077	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263
Case 12	144	263	263	704	1,204	1,542	2,170	2,170	2,170	2,170	2,305	2,466	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562
Case 13	144	763	1,263	1,763	2,263	3,013	3,763	4,024	4,248	4,873	4,897	4,897	5,063	5,063	5,063	5,063	5,063	5,063	5,063	5,063
Case 14	144	763	1,263	1,763	2,263	3,013	3,763	4,513	4,995	5,618	5,953	6,151	6,550	6,550	6,550	6,550	6,550	6,550	6,550	6,550
Case 15	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	6,862	6,862	6,862	6,862	6,862	6,862	6,862	6,862	6,862
Case 16	144	263	367	867	1,367	2,117	2,867	3,252	3,460	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862	3,862
Case 17	144	263	457	957	1,457	2,207	2,957	3,552	3,662	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163
Case 18	144	263	263	526	1,026	1,776	2,263	2,663	3,413	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163
Case 19	144	263	263	763	1,263	2,013	2,763	3,513	4,098	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363
Case 20	144	263	763	1,263	1,763	2,513	3,263	4,013	4,763	5,513	6,263	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 21	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465
Case 22	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 23	144	572	1,072	1,572	2,072	2,822	3,572	4,322	5,072	5,822	6,572	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 24	144	752	1,252	1,752	2,252	3,002	3,752	4,502	5,252	6,002	6,752	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 25	144	263	763	1,263	1,763	2,513	3,263	4,013	4,763	5,513	6,263	6,438	6,438	6,438	6,438	6,438	6,438	6,438	6,438	6,438
Case 26	144	263	763	1,263	1,763	2,513	3,263	4,013	4,763	5,513	6,263	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 27	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	6,943	6,943	6,943	6,943	6,943	6,943	6,943	6,943	6,943
Case 28	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,063	6,063	6,063	6,063	6,063	6,063	6,063	6,063	6,063	6,063
Case 29	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 30	144	263	263	413	913	1,663	2,413	3,163	3,913	4,663	5,413	6,163	6,913	7,263	7,263	7,263	7,263	7,263	7,263	7,263
Case 31	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 33	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,582	6,713	7,463	7,463	7,463	7,463	7,463	7,463	7,463	7,463
Case 34	144	263	616	1,074	1,574	2,324	2,563	2,563	2,696	3,446	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163	4,163
Case 35	144	763	1,263	1,763	2,263	3,013	3,763	4,511	4,837	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263	5,263
Case 36	144	263	263	763	1,263	2,013	2,763	3,513	4,136	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463	4,463
Case 37	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025
Case 38	144	263	263	263	471	471	771	961	1,118	1,868	2,381	2,381	2,381	2,381	2,381	2,381	2,381	2,381	2,381	2,381
Case 39	144	541	1,041	1,541	2,041	2,395	3,145	3,145	3,192	3,445	3,445	3,445	3,445	3,462	3,462	3,462	3,462	3,462	3,462	3,518
Case 40	144	263	263	263	263	263	403	596	754	1,504	2,254	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463
Case 41	144	263	263	570	1,070	1,447	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197
Case 42	144	263	607	1,107	1,607	2,357	3,107	3,561	3,611	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863	3,863
Case 43	144	763	1,263	1,763	2,263	3,013	3,763	4,513	5,263	6,013	6,763	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863	6,863
Case 44	144	263	263	263	263	263	263	598	1,259	2,009	2,582	3,332	3,444	3,563	3,862	4,612	5,362	5,542	5,750	5,936
Case 45	144	263	484	984	984	984	984	984	984	984	984	984	984	984	1,144	1,144	1,144	1,144	1,144	1,144
Case 46	144	263	463	463	463	603	763	863	863	863	1,163	1,163	1,163	1,163	1,606	1,651	1,651	1,651	1,651	1,651
Case 47	144	263	263	263	263	263	263	596	754	1,085	1,085	1,110	1,132	1,161	1,555	1,607	1,607	1,607	1,607	1,607
Case 48	144	263	263	544	1,044	1,313	2,063	2,234	2,388	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663	2,663

Table A.12 – Total Market Purchases Capacity Additions for 20 years

Market Purchase

(Figures shown are megawatts acquired in each year. Annual figures are not additive.)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01			301	801	933	1,055	989	939	1,039	1,422	1,566	1,638	1,388	1,388	1,438	1,438	1,438	1,438	1,438	1,388
Case 02			219	714	817	938	949	933	1,027	863	1,008	1,074	950	966	1,177	995	1,068	1,188	1,359	1,361
Case 03			129	601	648	749	709	891	967	604	739	800	491	608	881	942	728	834	1,504	1,433
Case 04				335	322	321	197	278	237	475	488	421	281	251	240	186	329	338	339	349
Case 05			220	716	817	935	936	914	1,004	1,365	1,500	1,566	1,308	1,389	1,377	1,329	1,588	1,588	1,638	1,588
Case 06		39	469	841	1,058	1,089	644	939	1,179	1,288	1,582	1,381	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638
Case 07				321	292	279	123	201	134	370	382	315	180	146	134	81	105	113	115	400
Case 08			200	683	758	859	821	939	1,010	1,358	1,500	1,561	1,206	1,558	1,588	1,453	1,588	1,588	1,588	1,543
Case 09			220	716	818	937	938	916	996	1,362	1,499	1,565	1,588	1,588	1,588	1,588	1,588	1,588	1,588	1,588
Case 10			213	705	798	902	867	939	1,010	1,358	1,468	1,529	1,574	1,588	1,588	1,588	1,588	1,588	1,588	1,588
Case 11			196	674	663	733	689	863	915	726	866	925	778	862	977	1,162	1,283	1,015	850	168
Case 12		30	457	1,037	943	1,089	633	939	1,177	1,173	1,445	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,700
Case 13				303	471	193	60	52	52	80	108	106								
Case 14			122	586	615	689	651	790	866	679	819	877	785	875	515	1,029	853	984	1,184	1,300
Case 15			367	940	1,075	1,089	989	939	1,160	1,148	1,437	1,638	1,588	1,588	1,374	1,588	1,237	1,571	1,588	1,638
Case 16				308	204	217	85	80	80	183	188	135					170	171	167	172
Case 17			197	673	688	764	701	875	947	1,287	1,429	1,487	1,518	1,588	1,588	1,588	1,588	1,588	1,588	1,588
Case 18			213	699	745	810	749	903	969	1,310	1,453	1,514	1,468	1,452	1,588	1,468	1,588	1,588	1,638	1,638
Case 19			207	682	695	794	707	881	944	1,287	1,429	1,488	1,532	1,588	1,572	1,543	1,588	1,588	1,650	1,700
Case 20			184	631	800	720	685	855	914	1,228	1,368	1,426	800	989	1,146	1,481	939	1,077	800	800
Case 21				302	198	200	60	54	453	72	97	94							480	480
Case 22			122	591	605	700	653	807	1,007	658	791	843	824	908	1,029	1,016	161	308	639	654
Case 23				305	201	209	79	67	55	90	112	109					480	480	480	480
Case 24			128	596	607	706	673	841	883	1,218	1,355	1,411	1,333	1,289	1,254	1,005	565	683	745	753
Case 25			185	661	800	850	850	1,015	1,530	1,530	1,530	1,530	1,530	1,268	1,530	1,349	1,468	1,268	1,518	993
Case 26			182	643	800	728	800	1,009	1,072	1,381	1,423	1,482	1,063	1,094	1,117	1,341	731	257	268	277
Case 27			126	593	800	800	800	987	1,019	1,352	1,390	1,443	1,330	1,194	1,366	1,477	1,280	1,480	1,480	517
Case 28				302	197	479	470	453	445	70	94	92						400		
Case 29			102	556	564	661	716	926	850	1,009	1,144	1,197	728	736	745	713	81	501	125	141
Case 30			197	681	764	791	738	863	922	1,256	1,373	1,414	1,319	1,287	1,276	1,191	550	70	86	88
Case 31			115	570	586	671	626	762	824	1,172	1,308	1,348	1,249	1,220	1,187	1,108	1,136	1,137	1,153	120
Case 33		18	371	889	846	850	984	833	1,014	814	1,092	837	838	838	838	838	838	838	838	838
Case 34			200	653	728	803	772	939	1,019	1,360	1,493	1,554	1,509	1,588	1,588	1,634	1,588	1,588	1,588	1,588
Case 35			122	578	632	726	690	851	933	750	895	956	873	970	1,104	1,145	1,293	1,296	1,182	567
Case 36			192	665	703	790	702	1,050	1,280	1,423	1,600	1,700	1,530	1,650	1,650	1,650	1,588	1,390	1,455	1,517
Case 37			122	592	637	736	697	856	1,064	1,245	1,388	206	60	63	81	76	109	124	645	662
Case 38			193	678	765	873	841	939	1,010	1,346	1,483	1,544	1,568	1,588	1,588	1,588	1,505	1,588	1,588	1,588
Case 39			156	596	617	713	668	739	817	626	770	830	738	770	788	788	788	788	850	788
Case 40			199	688	785	899	874	939	1,017	1,363	1,499	1,563	1,188	1,238	1,238	1,238	1,188	1,249	1,445	1,372
Case 41		91	440	931	937	1,037	983	933	1,018	1,387	1,523	1,584	1,552	1,563	1,563	1,485	1,563	1,563	1,563	1,634
Case 42		91	437	913	932	1,017	968	918	1,002	1,362	1,497	1,556	1,563	1,563	1,563	1,563	1,563	1,563	1,563	1,563
Case 43		50	352	830	842	932	892	933	992	1,311	1,454	1,521	1,436	1,399	1,337	1,071	575	691	755	763
Case 44			206	696	825	939	886	939	1,011	820	959	958	855	1,130	1,098	1,359	1,511	1,588	1,588	1,588
Case 45			227	713	847	968	976	928	1,019	861	1,004	1,068	943	1,048	1,140	1,188	1,188	1,232	1,372	1,355
Case 46			197	688	663	771	771	939	1,016	1,367	988	1,069	961	1,028	1,130	1,188	1,188	1,267	1,363	1,352
Case 47			205	696	670	784	784	939	1,016	1,367	988	1,053	939	1,020	1,123	1,188	1,188	1,188	1,349	1,346
Case 48			200	687	767	799	766	910	981	1,324	1,464	1,525	1,188	1,196	1,386	1,378	1,588	1,588	1,588	1,402

Table A.13 – Total Gas Capacity Additions for 20 years

Gas

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 02	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 03	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 04	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 05	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 06	3	3	3	1,072	1,072	1,072	1,699	1,699	1,699	2,174	2,174	2,649	2,649	2,649	2,649	2,649	2,649	2,649	2,649	2,649
Case 07	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 08	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 09	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 10	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 11	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 12	3	3	3	811	1,072	1,072	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699
Case 13	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 14	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 15	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 16	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 17	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 18	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 19	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 20	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 21	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 22	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 23	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 24	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 25	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 26	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 27	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 28	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 29	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 30	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 31	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 33	3	3	3	811	811	811	811	1,388	1,388	1,388	1,388	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911
Case 34	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 35	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 36	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 37	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 38	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 39	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 40	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 41	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 42	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 43	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 44	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811
Case 45	3	3	3	811	811	811	811	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072
Case 46	3	3	3	811	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985
Case 47	3	3	3	811	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985	985
Case 48	3	3	3	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811	811

Table A.14 – Total Conventional Coal Capacity Additions for 20 years

Conventional Coal

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 02	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 03	0	53	95	131	145	159	159	167	167	957	957	957	957	957	957	957	957	957	957	957
Case 04	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 05	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 06	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 07	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 08	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 09	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 10	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 11	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 12	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 13	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 14	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 15	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 16	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 17	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 18	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 19	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 20	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 21	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 22	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 23	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 24	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 25	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 26	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 27	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 28	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 29	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 30	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 31	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 33	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 34	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 35	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 36	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 37	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 38	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 39	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 40	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 41	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 42	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 43	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167
Case 44	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 45	0	53	95	131	145	159	159	167	167	767	767	767	767	767	767	767	767	767	767	767
Case 46	0	53	95	131	145	159	159	167	167	167	767	767	767	767	767	767	767	767	767	767
Case 47	0	53	95	131	145	159	159	167	167	167	767	767	767	767	767	767	767	767	767	767
Case 48	0	53	95	131	145	159	159	167	167	167	167	167	167	167	167	167	167	167	167	167

Table A.15 – Total Clean Coal Capacity Additions for 20 years

Clean Coal

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346
Case 05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346
Case 06	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 07	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346
Case 08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 09	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346
Case 10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	466	466	466	466
Case 15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	466	466	466	466
Case 16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,342	1,342	1,342	1,342
Case 30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,342	1,342	1,342	1,342
Case 31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 36	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876	876	876	876	876	876
Case 37	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876	876	876	876	876	876
Case 38	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	611	611	876	876
Case 41	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	876	876	876	876
Case 44	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 45	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 46	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Case 48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table A.16 – Total Demand-side Management Capacity Additions for 20 years

Demand Side Management

(Capacity MW)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	34	128	240	345	444	539	711	839	937	1,029	1,111	1,193	1,270	1,348	1,428	1,507	1,588	1,676	1,765	1,850
Case 02	103	240	368	488	591	693	795	894	1,000	1,097	1,184	1,271	1,361	1,453	1,546	1,639	1,731	1,826	1,925	2,022
Case 03	112	261	398	526	635	747	859	971	1,085	1,194	1,290	1,387	1,485	1,584	1,685	1,801	1,909	2,007	2,107	2,204
Case 04	97	233	361	481	582	684	787	886	991	1,087	1,174	1,261	1,351	1,443	1,536	1,629	1,721	1,816	1,912	2,006
Case 05	101	238	365	485	591	694	799	904	1,011	1,108	1,195	1,282	1,372	1,464	1,557	1,650	1,750	1,847	1,945	2,042
Case 06	105	246	377	504	612	850	962	1,074	1,187	1,287	1,383	1,478	1,575	1,675	1,776	1,892	1,999	2,105	2,209	2,313
Case 07	105	246	377	500	605	710	815	920	1,027	1,125	1,213	1,301	1,396	1,493	1,586	1,680	1,773	1,869	1,965	2,062
Case 08	106	248	379	503	613	723	834	951	1,064	1,167	1,263	1,357	1,453	1,550	1,650	1,755	1,857	1,956	2,056	2,154
Case 09	101	238	366	486	589	693	798	902	1,009	1,106	1,193	1,281	1,371	1,462	1,555	1,649	1,749	1,845	1,944	2,041
Case 10	103	244	375	499	605	716	828	945	1,058	1,161	1,257	1,352	1,447	1,544	1,644	1,750	1,851	1,950	2,050	2,148
Case 11	111	260	397	526	639	754	868	982	1,097	1,213	1,310	1,407	1,506	1,607	1,708	1,825	1,933	2,038	2,138	2,236
Case 12	111	258	395	531	643	840	953	1,084	1,198	1,306	1,404	1,506	1,628	1,733	1,841	1,974	2,083	2,195	2,307	2,412
Case 13	112	261	399	530	644	758	872	986	1,100	1,209	1,306	1,404	1,503	1,603	1,705	1,822	1,929	2,035	2,139	2,243
Case 14	115	269	407	540	654	769	883	998	1,114	1,230	1,328	1,426	1,531	1,637	1,739	1,856	1,964	2,071	2,175	2,278
Case 15	120	278	424	563	690	819	948	1,161	1,284	1,398	1,501	1,616	1,722	1,829	1,937	2,070	2,179	2,285	2,389	2,493
Case 16	106	248	380	508	617	729	840	951	1,065	1,167	1,263	1,358	1,454	1,554	1,656	1,772	1,880	1,987	2,091	2,195
Case 17	107	254	391	520	630	742	854	967	1,089	1,197	1,295	1,392	1,491	1,591	1,693	1,810	1,918	2,024	2,128	2,232
Case 18	103	244	376	499	609	721	833	944	1,064	1,166	1,262	1,357	1,452	1,550	1,651	1,767	1,874	1,980	2,083	2,186
Case 19	106	248	384	512	623	735	847	958	1,079	1,187	1,284	1,382	1,481	1,581	1,682	1,799	1,907	2,014	2,118	2,221
Case 20	112	261	398	531	645	760	875	988	1,110	1,219	1,316	1,414	1,513	1,613	1,714	1,831	1,939	2,045	2,149	2,247
Case 21	115	269	407	539	653	768	883	997	1,113	1,222	1,320	1,418	1,517	1,618	1,720	1,837	1,946	2,053	2,157	2,263
Case 22	115	269	407	540	655	775	897	1,017	1,140	1,260	1,363	1,465	1,570	1,676	1,784	1,901	2,010	2,117	2,221	2,327
Case 23	112	261	398	531	645	759	873	987	1,102	1,210	1,308	1,406	1,505	1,606	1,708	1,825	1,933	2,040	2,145	2,250
Case 24	112	261	399	532	647	762	876	990	1,105	1,221	1,323	1,426	1,531	1,637	1,745	1,863	1,971	2,078	2,183	2,288
Case 25	107	255	392	524	638	753	868	981	1,104	1,212	1,309	1,407	1,506	1,606	1,708	1,824	1,932	2,039	2,143	2,247
Case 26	112	261	398	531	645	760	875	988	1,111	1,219	1,316	1,414	1,513	1,613	1,714	1,831	1,939	2,046	2,150	2,254
Case 27	112	266	404	537	651	771	893	1,012	1,136	1,257	1,360	1,464	1,569	1,676	1,784	1,901	2,008	2,114	2,213	2,310
Case 28	115	269	407	540	654	769	884	998	1,114	1,222	1,321	1,419	1,518	1,619	1,721	1,838	1,941	2,040	2,141	2,241
Case 29	116	275	421	560	681	802	925	1,045	1,274	1,394	1,497	1,600	1,706	1,813	1,923	2,057	2,167	2,279	2,391	2,498
Case 30	111	260	398	527	642	757	871	985	1,106	1,215	1,313	1,416	1,521	1,627	1,735	1,869	1,977	2,084	2,196	2,303
Case 31	116	270	416	554	674	795	918	1,039	1,162	1,284	1,387	1,490	1,596	1,703	1,813	1,947	2,057	2,164	2,268	2,371
Case 33	121	281	427	610	735	884	1,065	1,190	1,324	1,444	1,556	1,666	1,778	1,893	2,009	2,147	2,271	2,392	2,513	2,624
Case 34	106	247	379	502	607	718	828	946	1,060	1,162	1,258	1,353	1,448	1,546	1,646	1,751	1,853	1,951	2,051	2,149
Case 35	115	269	407	540	654	768	883	996	1,112	1,227	1,324	1,421	1,520	1,620	1,721	1,837	1,939	2,037	2,137	2,234
Case 36	111	259	397	527	642	756	871	985	1,106	1,214	1,316	1,521	1,620	1,720	1,822	1,939	2,046	2,153	2,257	2,361
Case 37	115	269	407	540	654	770	885	999	1,115	1,231	1,329	1,427	1,527	1,628	1,730	1,847	1,956	2,063	2,167	2,273
Case 38	107	248	384	512	623	734	846	1,021	1,135	1,237	1,334	1,428	1,524	1,621	1,721	1,826	1,928	2,034	2,137	2,240
Case 39	115	269	408	541	655	771	885	1,109	1,225	1,334	1,432	1,530	1,634	1,740	1,848	1,982	2,093	2,206	2,319	2,426
Case 40	105	246	376	499	604	710	816	1,024	1,131	1,229	1,316	1,403	1,493	1,590	1,688	1,792	1,893	1,991	2,090	2,188
Case 41	106	248	379	506	618	729	854	968	1,081	1,183	1,280	1,374	1,470	1,567	1,667	1,772	1,874	1,972	2,072	2,171
Case 42	106	254	391	520	629	740	852	965	1,079	1,188	1,285	1,382	1,481	1,581	1,683	1,800	1,908	2,014	2,118	2,222
Case 43	115	269	407	540	654	774	896	1,121	1,236	1,346	1,448	1,551	1,656	1,762	1,870	1,988	2,096	2,203	2,308	2,413
Case 44	102	239	367	487	590	695	800	1,013	1,118	1,213	1,298	1,383	1,472	1,562	1,655	1,748	1,840	1,935	2,031	2,125
Case 45	97	229	356	475	578	680	782	882	987	1,084	1,170	1,258	1,348	1,439	1,532	1,626	1,717	1,813	1,908	2,002
Case 46	103	240	368	489	591	696	802	926	1,033	1,131	1,218	1,305	1,395	1,487	1,580	1,673	1,765	1,860	1,956	2,050
Case 47	102	239	367	488	591	695	801	933	1,040	1,137	1,223	1,311	1,401	1,493	1,585	1,679	1,771	1,866	1,962	2,055
Case 48	114	261	395	518	628	811	921	1,055	1,168	1,271	1,367	1,461	1,557	1,654	1,754	1,859	1,961	2,060	2,160	2,258

Table A.17 – Total Other Capacity Additions for 20 years

Other

(Capacity MW) (Other includes Distributed Generation, Other Renewables, and Nuclear)

Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Case 01	13	27	40	79	117	156	169	183	191	199	205	205	205	205	205	205	205	205	205	205
Case 02	8	17	25	58	126	159	167	176	184	194	196	199	202	205	207	210	213	215	218	219
Case 03	8	17	31	64	202	241	274	308	316	324	324	324	324	324	324	324	324	324	324	324
Case 04	8	17	25	58	126	159	170	180	190	201	203	206	209	211	214	217	217	218	219	219
Case 05	8	17	25	58	126	161	172	183	194	205	208	210	213	216	218	219	219	219	219	219
Case 06	14	29	43	83	174	289	330	401	412	422	424	426	434	435	437	438	438	438	438	438
Case 07	8	17	25	58	126	159	194	204	240	251	253	256	259	262	264	267	268	269	269	269
Case 08	10	23	37	82	156	196	243	319	330	341	344	346	349	351	353	354	354	354	354	354
Case 09	8	17	25	58	126	160	171	182	193	204	207	210	212	215	217	219	219	219	219	219
Case 10	8	17	25	60	129	163	213	324	335	346	349	352	354	355	357	358	358	358	358	358
Case 11	8	17	25	64	202	241	277	312	322	333	335	337	339	341	343	343	343	343	343	343
Case 12	13	27	41	87	231	270	318	359	370	381	384	391	394	395	397	398	398	803	1,188	1,203
Case 13	8	17	31	70	208	241	274	308	316	324	324	324	324	324	324	324	324	324	324	324
Case 14	8	17	37	71	209	243	279	315	326	337	340	342	345	347	349	349	349	349	349	349
Case 15	14	28	55	94	239	528	819	861	872	883	885	892	894	895	897	898	2,498	2,498	2,498	2,498
Case 16	8	17	25	71	210	244	280	316	327	338	341	343	346	348	350	351	351	351	351	351
Case 17	8	17	25	72	211	245	281	317	328	339	342	345	347	348	350	351	351	351	351	351
Case 18	8	17	26	72	176	246	282	318	329	340	342	345	347	348	350	351	351	351	351	351
Case 19	8	17	26	72	211	246	282	318	329	340	342	345	347	348	350	351	351	351	351	351
Case 20	8	17	25	70	208	242	277	312	323	333	335	337	339	342	344	344	1,944	1,944	1,944	1,944
Case 21	8	17	31	70	208	241	274	308	316	324	324	324	324	324	324	324	1,924	1,924	1,924	1,924
Case 22	8	17	31	70	208	242	278	313	322	331	331	331	331	331	331	331	1,931	1,931	1,931	1,931
Case 23	8	17	27	73	212	246	282	318	329	340	343	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 24	9	18	28	74	213	248	284	320	331	341	344	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 25	9	18	28	74	213	248	283	319	330	341	344	345	347	348	350	351	351	351	351	351
Case 26	9	18	28	74	213	248	283	319	330	341	344	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 27	8	17	26	72	211	246	282	318	329	340	342	345	347	348	350	350	3,550	3,550	3,550	3,550
Case 28	8	17	31	70	208	241	274	308	316	324	324	324	324	324	324	324	3,524	3,524	3,524	3,524
Case 29	9	23	43	89	233	272	314	355	371	387	389	391	394	395	397	397	3,597	3,597	3,597	3,597
Case 30	8	17	25	60	135	210	246	317	328	339	342	345	347	348	350	351	3,551	3,551	3,551	3,551
Case 31	9	18	39	73	211	246	282	318	329	340	342	344	346	348	350	351	3,551	3,551	3,551	3,551
Case 33	14	28	49	94	489	778	819	861	877	888	890	891	894	895	897	898	898	1,303	1,688	1,688
Case 34	8	17	29	74	147	187	234	275	286	297	300	303	306	308	310	311	311	311	311	311
Case 35	9	18	39	72	175	208	241	275	283	291	291	291	291	291	291	291	291	291	291	291
Case 36	8	17	31	83	192	232	268	309	325	341	349	357	359	360	362	363	363	363	363	363
Case 37	8	17	31	70	173	206	239	273	281	289	289	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489
Case 38	13	27	40	80	154	194	235	276	287	298	300	303	306	308	309	311	311	311	311	311
Case 39	13	27	46	85	193	237	276	314	328	336	336	336	336	336	336	336	336	338	341	344
Case 40	13	27	40	79	152	190	229	267	276	284	284	284	284	284	284	284	284	284	284	284
Case 41	13	27	41	87	231	276	318	359	370	381	384	386	388	390	391	393	393	393	393	393
Case 42	8	17	25	72	211	245	281	317	328	339	342	345	347	348	350	351	351	351	351	351
Case 43	15	29	44	96	240	279	321	362	373	384	385	387	388	390	391	393	3,593	3,593	3,593	3,593
Case 44	13	27	40	79	118	158	233	274	283	291	291	328	330	332	334	336	373	376	378	379
Case 45	6	13	21	54	88	121	131	176	187	198	203	207	210	213	250	253	279	304	304	305
Case 46	13	27	40	79	118	158	174	190	200	211	213	216	219	222	224	226	226	226	226	226
Case 47	13	27	40	79	118	158	174	190	200	211	213	216	219	222	224	226	226	226	226	226
Case 48	8	17	25	64	132	167	203	239	256	267	270	272	275	278	280	281	281	281	281	281

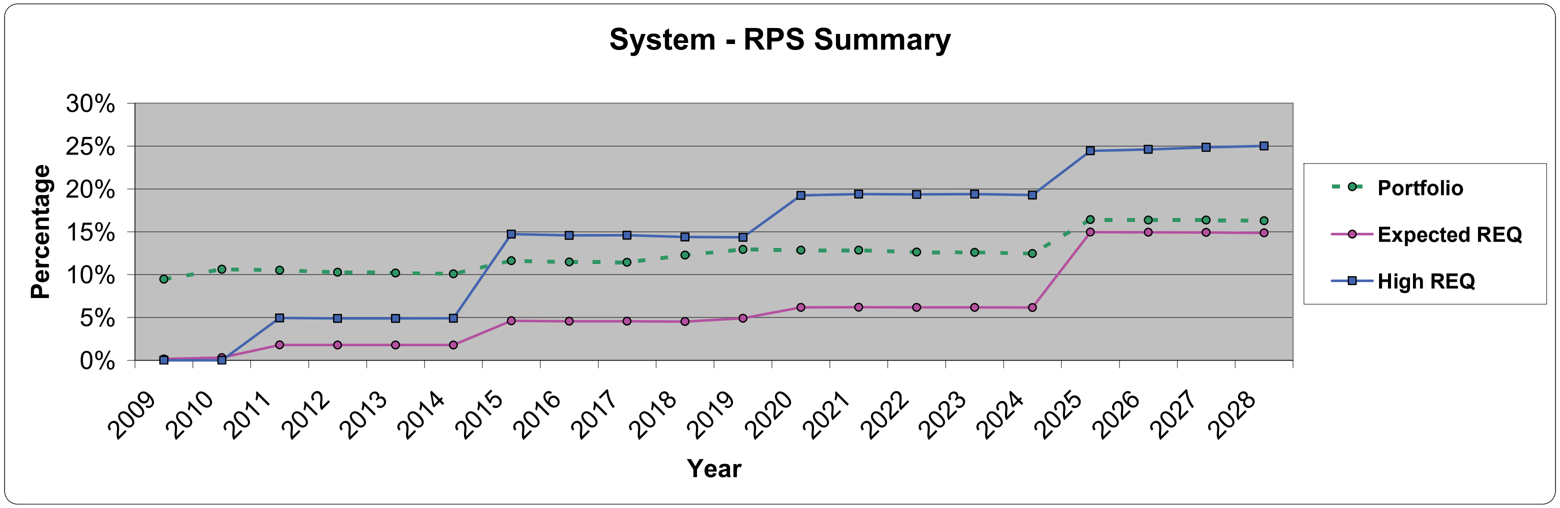
DETAILED PORTFOLIO DATA

Renewable Portfolio Summary by Case

For each case, PacifiCorp generated an RPS compliance report. This report shows the annual system RPS requirements, REC bank balances, REC-adjusted qualifying generation, RPS compliance percentages, and the system load used in the calculations. The report also includes a line chart comparing the RPS compliance and system generation requirements percentages for both the base and high RPS scenarios (Expected REQ and High REQ, respectively). See Chapter 7 “Representation and Modeling of Renewable Portfolio Standards” for additional information.

System - RPS Report - Case # 1

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,131	18,404	21,743	25,007	28,225	31,466	34,074	35,843	37,610	39,340	40,915	42,474	43,948	39,329	34,645	29,878	25,051
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	340	345	357	118	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	1,376	2,519	2,952	3,376	3,782	4,166	2,986	1,794	581	-	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,534**	**15,343**	**18,847**	**22,531**	**26,266**	**28,111**	**30,019**	**32,048**	**34,074**	**35,843**	**37,610**	**39,340**	**40,915**	**42,474**	**43,948**	**39,329**	**34,645**	**29,878**	**25,051**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,205	3,211	3,273	3,340	3,264	3,281	3,306	3,314	3,334	3,357	3,370	3,321	3,337	3,342	5,257	5,301	5,358	5,391
Other (ID,WY)	822	1,022	1,034	1,046	1,052	1,071	1,018	1,029	1,038	1,035	1,038	1,041	1,042	1,010	1,013	983	991	996	1,003	1,009
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	290	299	303	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	982	1,143	1,133	1,132	1,126	1,116	2,228	2,244	2,266	2,918	3,163	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,107**	**5,807**	**5,850**	**5,873**	**5,953**	**6,043**	**7,104**	**7,160**	**7,229**	**7,897**	**8,430**	**8,465**	**8,525**	**8,469**	**8,524**	**8,534**	**11,317**	**11,396**	**11,503**	**11,586**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	10%	10%	12%	11%	11%	12%	13%	13%	13%	13%	13%	12%	16%	16%	16%	16%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

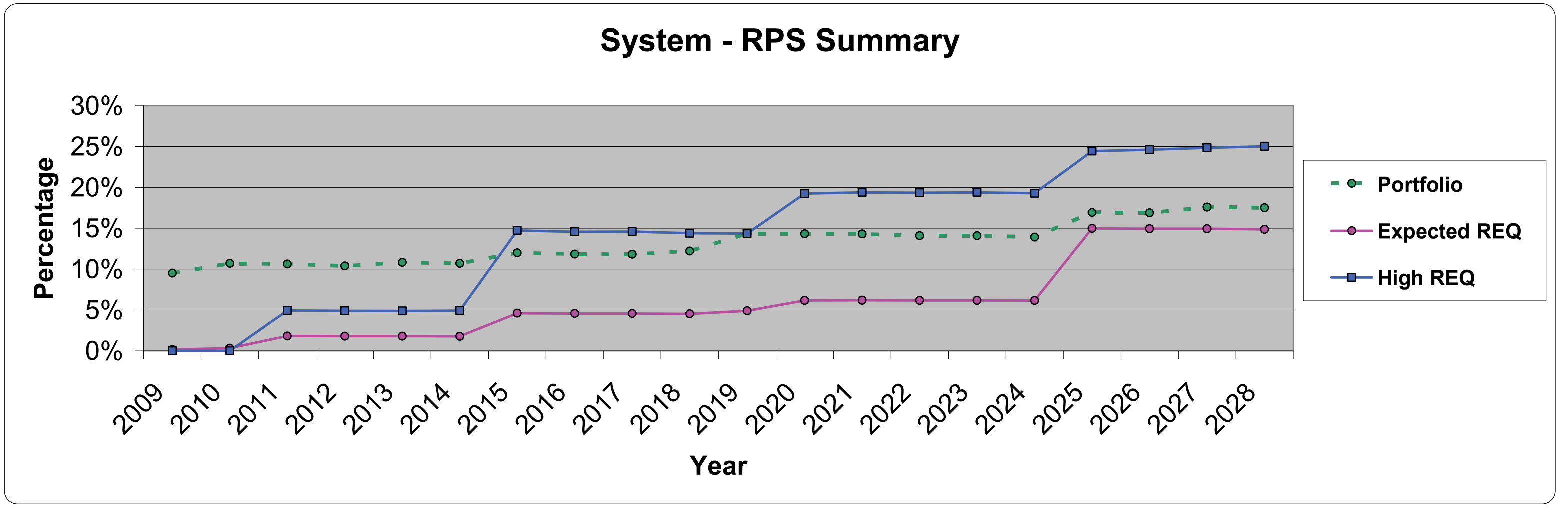


Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded

System - RPS Report - Case # 2

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,743	11,975	15,216	18,646	22,145	25,557	28,947	32,369	36,054	38,983	42,216	45,419	48,470	51,548	54,519	51,372	48,147	46,782	45,340
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	350	380	415	174	-	-	2	-	-	-	-	-	-	-	-	-	-
Oregon	1,382	2,536	2,985	3,428	3,928	4,407	3,315	2,209	1,086	82	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,941**	**11,583**	**15,439**	**18,994**	**22,954**	**26,967**	**29,047**	**31,156**	**33,455**	**36,139**	**38,983**	**42,216**	**45,419**	**48,470**	**51,548**	**54,519**	**51,372**	**48,147**	**46,782**	**45,340**
Adjusted Qualifying Renewables																				
Utah	2,959	3,184	3,231	3,241	3,430	3,499	3,412	3,427	3,459	3,685	3,942	3,971	3,987	3,939	3,974	3,969	5,257	5,301	5,358	5,391
Other (ID,WY)	828	1,032	1,049	1,063	1,141	1,162	1,103	1,113	1,126	1,249	1,389	1,398	1,402	1,371	1,386	1,349	1,355	1,361	1,861	1,872
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	328	332	370	372	375	379	632	636	640	644	647	651	655	659	662	666
Oregon	988	1,155	1,149	1,150	1,220	1,211	2,228	2,244	2,266	2,277	3,106	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,129**	**5,850**	**5,912**	**5,945**	**6,322**	**6,417**	**7,337**	**7,389**	**7,469**	**7,843**	**9,331**	**9,437**	**9,502**	**9,448**	**9,534**	**9,527**	**11,681**	**11,761**	**12,361**	**12,449**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	11%	11%	12%	12%	12%	12%	14%	14%	14%	14%	14%	14%	17%	17%	18%	17%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

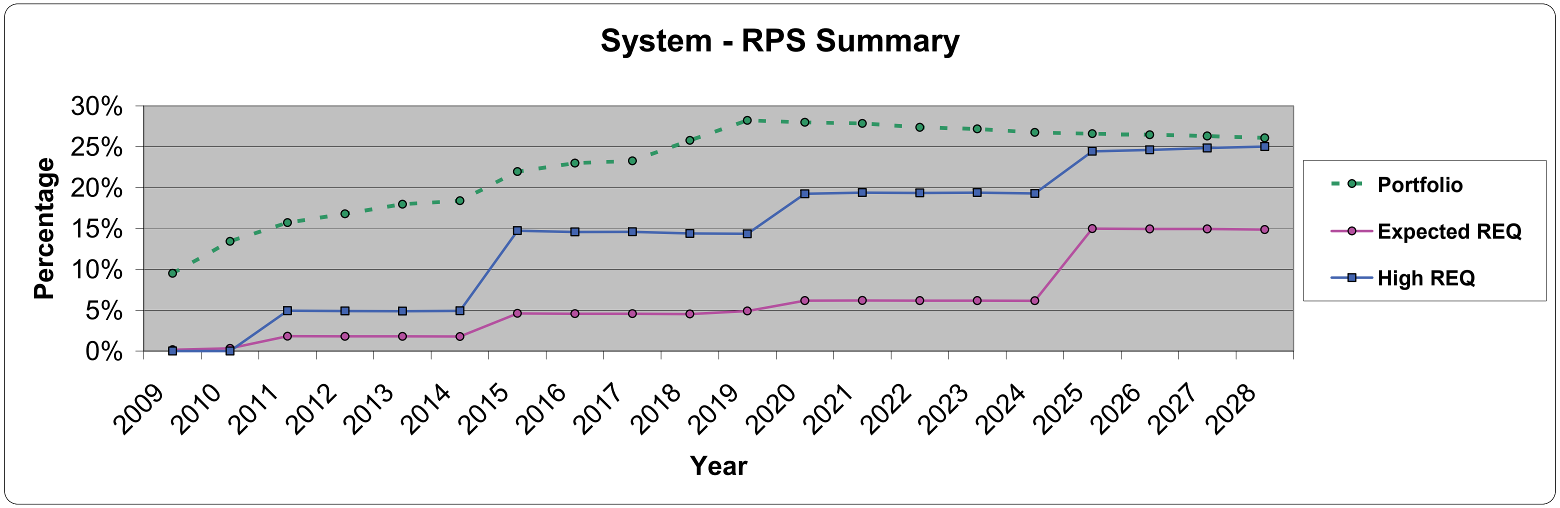


Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded

System - RPS Report - Case # 3

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,377	13,818	18,615	23,830	29,290	35,777	42,658	49,694	57,515	66,116	74,739	83,394	91,990	100,611	109,224	112,576	115,904	119,184	122,434
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	419	816	855	990	1,099	1,093	1,120	1,210	1,373	1,398	1,274	1,264	1,247	1,231	1,224	1,204	1,180	1,159	1,136
Oregon	1,382	2,926	4,110	5,493	7,067	8,711	9,436	10,362	11,338	12,766	14,613	15,629	16,604	17,516	18,394	19,221	19,137	18,978	18,730	18,388
Cumulative Surplus Credit Bank Balance	**6,942**	**12,721**	**18,744**	**24,963**	**31,887**	**39,099**	**46,306**	**54,140**	**62,242**	**71,655**	**82,126**	**91,642**	**101,261**	**110,752**	**120,236**	**129,670**	**132,917**	**136,062**	**139,074**	**141,958**
Adjusted Qualifying Renewables																				
Utah	2,960	3,817	4,441	4,797	5,215	5,460	6,487	6,881	7,037	7,821	8,600	8,624	8,654	8,596	8,621	8,613	8,609	8,629	8,638	8,640
Other (ID,WY)	828	1,380	1,721	1,932	2,144	2,279	2,867	3,102	3,193	3,633	4,078	4,105	4,125	4,091	4,107	4,059	4,081	4,115	4,142	4,164
California	88	176	185	194	204	213	223	233	243	269	300	336	339	341	345	348	352	354	357	360
Washington	266	419	519	580	654	690	896	966	991	1,134	1,272	1,269	1,271	1,260	1,261	1,260	1,250	1,244	1,237	1,228
Oregon	989	1,543	1,885	2,091	2,294	2,376	2,953	3,170	3,242	3,706	4,146	4,112	4,108	4,066	4,061	4,038	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**7,335**	**8,750**	**9,593**	**10,511**	**11,018**	**13,427**	**14,353**	**14,706**	**16,563**	**18,396**	**18,445**	**18,497**	**18,354**	**18,395**	**18,318**	**18,353**	**18,428**	**18,496**	**18,552**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	17%	18%	18%	22%	23%	23%	26%	28%	28%	28%	27%	27%	27%	27%	26%	26%	26%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

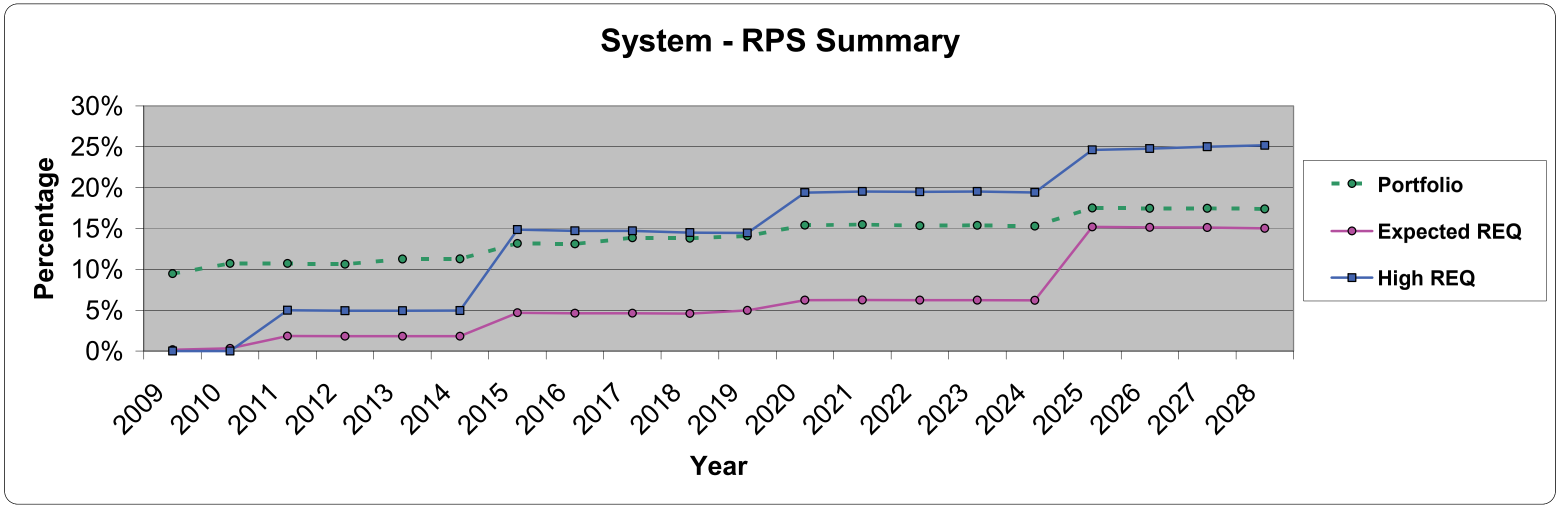


Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 4

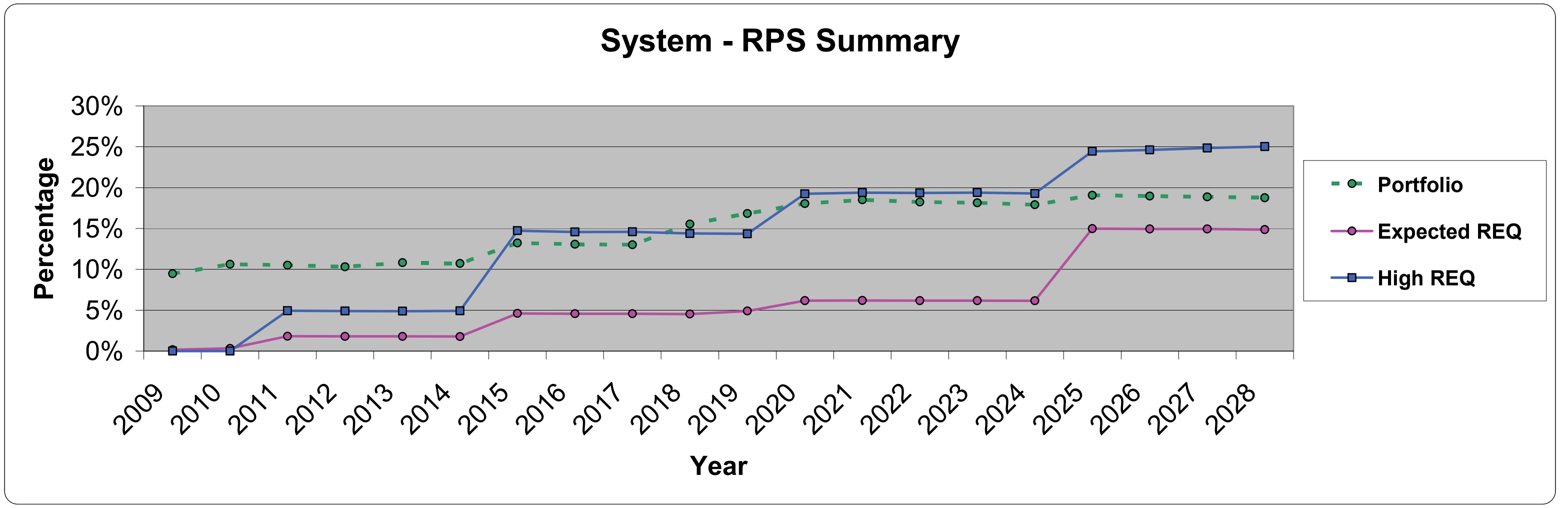
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,550	8,715	11,919	15,138	18,571	22,075	25,704	29,360	33,272	37,195	41,062	44,887	48,563	52,128	55,719	59,250	57,591	55,984	54,409	52,888
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	472	344	381	424	235	47	96	144	-	-	-	-	-	-	-	-	-	-
Oregon	1,376	2,519	2,958	3,402	3,926	4,437	3,587	2,753	2,057	1,382	710	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,534**	**15,349**	**18,883**	**22,878**	**26,935**	**29,526**	**32,160**	**35,425**	**38,721**	**41,773**	**44,887**	**48,563**	**52,128**	**55,719**	**59,250**	**57,591**	**55,984**	**54,409**	**52,888**
Adjusted Qualifying Renewables																				
Utah	2,950	3,165	3,204	3,219	3,433	3,503	3,629	3,656	3,912	3,923	3,948	3,978	3,993	3,942	3,957	3,952	4,505	4,479	4,464	4,426
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,228	1,245	1,387	1,386	1,392	1,402	1,405	1,372	1,376	1,338	1,345	1,351	1,357	1,363
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	264	300	293	292	328	333	374	377	421	423	577	574	572	568	564	561	558	554	550	546
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Adjusted Qualifying Renewables	**5,108**	**5,806**	**5,848**	**5,891**	**6,330**	**6,426**	**7,568**	**7,616**	**8,063**	**8,071**	**8,262**	**9,033**	**9,050**	**8,946**	**8,952**	**8,898**	**10,141**	**10,095**	**10,068**	**10,019**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	9%	11%	11%	11%	11%	11%	13%	13%	14%	14%	14%	15%	15%	15%	15%	15%	18%	17%	17%	17%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description
CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 5

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,138	18,572	22,075	25,936	29,823	33,735	38,638	44,089	49,570	55,262	60,902	66,558	72,209	72,622	73,013	73,368	73,712
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	93	270	290	125	149	166	149	141	126	107	89	71
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,537	2,702	1,844	1,557	1,555	739	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,860**	**22,831**	**26,856**	**29,730**	**32,619**	**35,671**	**40,465**	**45,934**	**50,434**	**55,411**	**61,068**	**66,707**	**72,350**	**72,748**	**73,120**	**73,457**	**73,783**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	3,861	3,887	3,912	4,903	5,451	5,481	5,692	5,640	5,656	5,651	5,671	5,692	5,713	5,734
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,360	1,378	1,387	1,951	2,260	2,277	2,396	2,365	2,370	2,330	2,347	2,364	2,380	2,396
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	417	420	421	602	697	695	730	720	720	719	713	708	702	697
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,891**	**6,330**	**6,427**	**8,089**	**8,162**	**8,229**	**9,986**	**10,971**	**11,885**	**12,290**	**12,220**	**12,273**	**12,258**	**13,144**	**13,204**	**13,275**	**13,347**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	13%	16%	17%	18%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

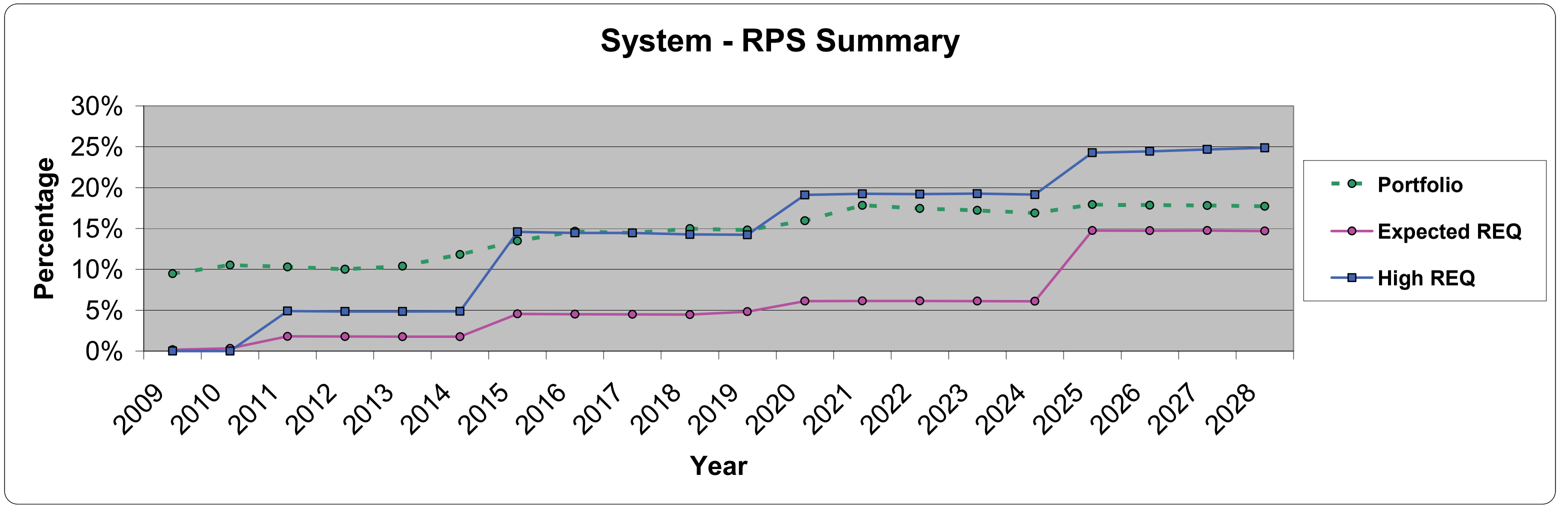


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 6

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,508	26,682	31,430	36,202	41,314	46,451	51,553	57,643	63,683	69,738	75,787	75,755	75,599	75,172	74,493
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	470	339	371	488	371	269	359	408	181	-	87	153	119	93	59	21	-	-
Oregon	1,376	2,519	2,945	3,359	3,839	4,547	3,788	3,314	2,789	2,423	2,006	658	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,335**	**18,836**	**22,783**	**27,542**	**30,841**	**35,013**	**39,350**	**44,146**	**48,638**	**52,211**	**57,731**	**63,836**	**69,856**	**75,880**	**75,814**	**75,619**	**75,172**	**74,493**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,936	4,175	4,748	4,772	5,112	5,137	5,167	6,091	6,040	6,055	6,050	6,103	6,233	6,383	6,509
Other (ID,WY)	823	1,022	1,034	1,050	1,143	1,411	1,540	1,874	1,885	2,071	2,078	2,094	2,629	2,598	2,604	2,563	2,583	2,602	2,621	2,639
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	264	300	293	292	328	412	474	577	578	640	691	703	803	793	793	792	786	781	793	807
Oregon	982	1,143	1,133	1,137	1,222	1,471	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,849**	**5,892**	**6,331**	**7,443**	**8,760**	**9,822**	**9,919**	**10,558**	**10,704**	**11,780**	**13,428**	**13,406**	**13,509**	**13,545**	**14,665**	**14,902**	**15,192**	**15,462**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	9%	11%	10%	10%	10%	12%	13%	15%	14%	15%	15%	16%	18%	17%	17%	17%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

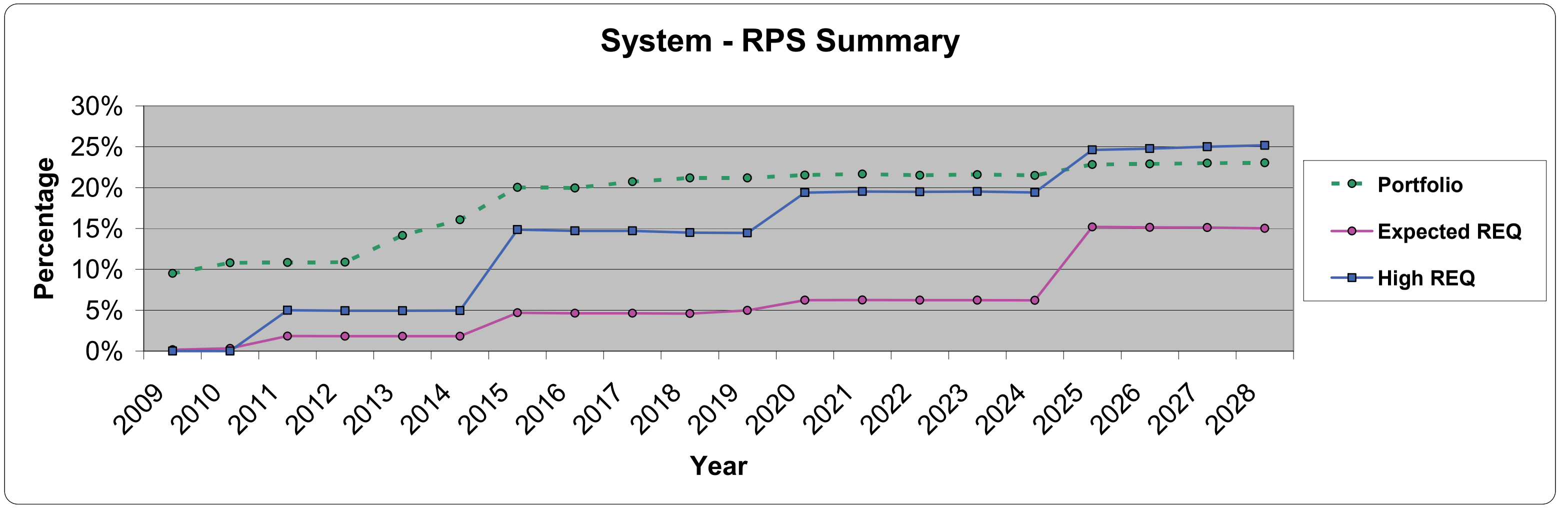


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = High, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 7

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	8,742	11,973	15,249	19,371	24,034	29,708	35,410	41,318	47,369	53,444	59,550	65,670	71,739	77,824	83,903	85,497	87,139	88,817	90,555
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	480	359	517	761	821	794	834	898	697	469	471	467	464	470	470	465	462	459
Oregon	1,382	2,536	2,991	3,469	4,408	5,608	5,966	6,335	6,812	7,387	7,965	7,832	7,690	7,525	7,361	7,181	6,281	5,368	4,435	3,482
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,444**	**19,077**	**24,296**	**30,403**	**36,495**	**42,539**	**48,964**	**55,654**	**62,106**	**67,851**	**73,831**	**79,731**	**85,649**	**91,554**	**92,248**	**92,972**	**93,715**	**94,496**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,276	4,122	4,663	5,674	5,701	5,909	6,051	6,075	6,106	6,120	6,069	6,084	6,079	6,100	6,121	6,142	6,163
Other (ID,WY)	828	1,031	1,049	1,082	1,530	1,825	2,401	2,423	2,541	2,612	2,620	2,640	2,647	2,615	2,621	2,580	2,600	2,620	2,638	2,657
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	266	303	298	302	454	544	748	751	785	811	811	809	808	799	798	797	792	786	781	775
Oregon	989	1,154	1,149	1,171	1,637	1,903	2,473	2,476	2,580	2,665	2,664	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Adjusted Qualifying Renewables	**5,130**	**5,845**	**5,912**	**6,025**	**7,946**	**9,148**	**11,518**	**11,582**	**12,056**	**12,389**	**12,430**	**12,633**	**12,655**	**12,547**	**12,559**	**12,503**	**13,224**	**13,236**	**13,258**	**13,280**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	11%	11%	11%	14%	16%	20%	20%	21%	21%	21%	22%	22%	22%	22%	21%	23%	23%	23%	23%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

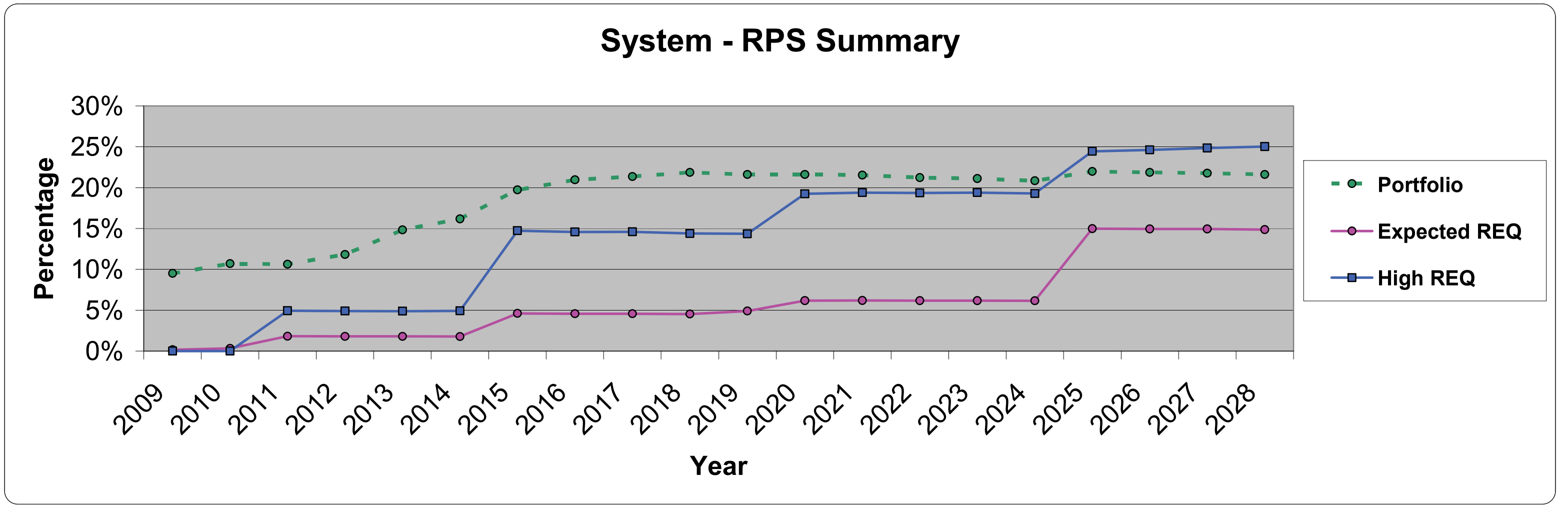


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 8

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,742	11,973	15,559	19,990	24,883	30,787	37,127	43,651	50,409	57,191	64,004	70,831	77,608	84,399	91,185	92,735	94,262	95,752	97,232
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	413	625	852	883	915	1,018	1,086	872	611	599	581	564	556	541	522	504	486
Oregon	1,382	2,536	2,984	3,635	4,738	6,045	6,426	7,033	7,708	8,511	9,291	9,251	9,164	9,020	8,839	8,606	7,484	6,301	5,044	3,715
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,436**	**19,607**	**25,353**	**31,780**	**38,097**	**45,074**	**52,376**	**60,006**	**67,354**	**73,866**	**80,595**	**87,208**	**93,802**	**100,347**	**100,760**	**101,084**	**101,301**	**101,433**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,586	4,431	4,893	5,904	6,339	6,524	6,758	6,782	6,813	6,827	6,776	6,791	6,786	6,807	6,828	6,849	6,870
Other (ID,WY)	828	1,031	1,049	1,255	1,703	1,956	2,533	2,790	2,897	3,020	3,029	3,051	3,059	3,028	3,035	2,993	3,017	3,041	3,064	3,087
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	359	511	586	790	867	898	940	940	938	937	928	927	926	921	915	910	904
Oregon	989	1,154	1,149	1,359	1,823	2,040	2,609	2,851	2,941	3,081	3,079	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**6,752**	**8,672**	**9,689**	**12,059**	**13,081**	**13,503**	**14,052**	**14,093**	**14,234**	**14,296**	**14,227**	**14,281**	**14,264**	**15,158**	**15,224**	**15,303**	**15,382**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	15%	16%	20%	21%	21%	22%	22%	22%	22%	21%	21%	21%	22%	22%	22%	22%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

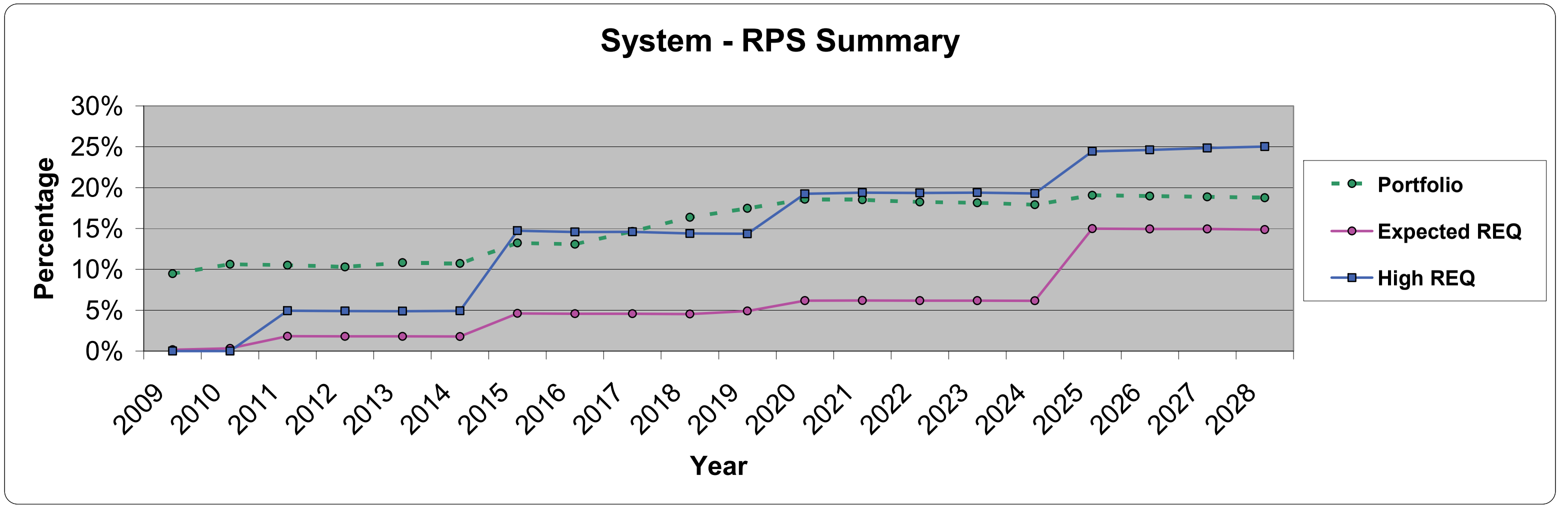

System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 9

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,137	18,571	22,074	25,934	29,822	34,314	39,519	45,146	50,823	56,515	62,155	67,811	73,461	73,875	74,266	74,621	74,964
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	199	431	377	193	184	166	149	141	126	107	89	71
Oregon	1,376	2,519	2,952	3,380	3,882	4,363	3,537	2,701	2,184	2,074	2,175	1,474	727	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**18,858**	**22,829**	**26,854**	**29,728**	**32,617**	**36,697**	**42,023**	**47,699**	**52,489**	**57,426**	**62,321**	**67,960**	**73,602**	**74,001**	**74,373**	**74,710**	**75,036**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,217	3,433	3,503	3,861	3,887	4,492	5,205	5,628	5,677	5,692	5,640	5,656	5,651	5,671	5,692	5,713	5,734
Other (ID,WY)	822	1,022	1,034	1,049	1,143	1,164	1,360	1,378	1,723	2,125	2,362	2,390	2,396	2,365	2,370	2,330	2,347	2,364	2,380	2,396
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	291	328	333	417	420	527	657	730	731	730	720	720	719	713	708	702	697
Oregon	982	1,144	1,133	1,136	1,222	1,214	2,228	2,244	2,266	2,277	2,401	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**5,888**	**6,331**	**6,427**	**8,089**	**8,162**	**9,251**	**10,516**	**11,383**	**12,230**	**12,290**	**12,220**	**12,273**	**12,258**	**13,144**	**13,204**	**13,275**	**13,347**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	15%	16%	17%	19%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

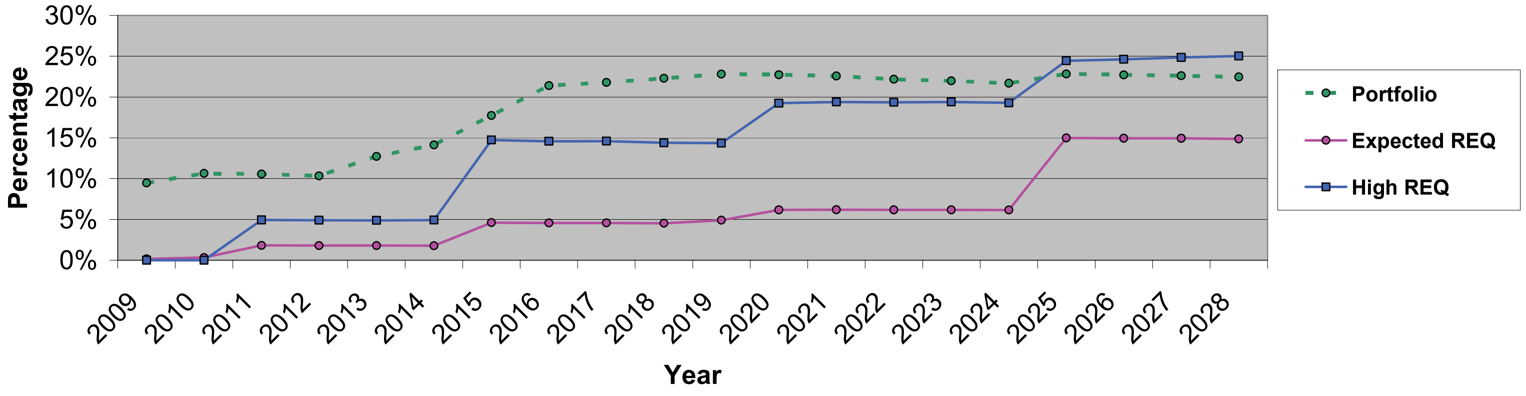


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 10

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,551	8,721	11,942	15,168	19,073	23,448	28,834	35,289	41,929	48,803	55,917	63,061	70,220	77,328	84,451	91,569	93,450	95,308	97,131	98,941
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	475	346	464	662	694	841	1,060	1,128	953	732	720	702	685	677	662	643	625	607
Oregon	1,376	2,522	2,965	3,398	4,185	5,184	5,258	5,934	6,677	7,548	8,522	8,676	8,782	8,830	8,841	8,800	7,869	6,875	5,805	4,661
Cumulative Surplus Credit Bank Balance	**6,927**	**11,544**	**15,381**	**18,912**	**23,722**	**29,293**	**34,786**	**42,064**	**49,666**	**57,479**	**65,392**	**72,469**	**79,722**	**86,860**	**93,977**	**101,046**	**101,981**	**102,826**	**103,561**	**104,209**
Adjusted Qualifying Renewables																				
Utah	2,950	3,170	3,221	3,226	3,906	4,375	5,386	6,455	6,640	6,874	7,114	7,144	7,159	7,108	7,123	7,118	7,138	7,159	7,180	7,202
Other (ID,WY)	823	1,025	1,043	1,054	1,408	1,661	2,235	2,857	2,964	3,087	3,220	3,244	3,253	3,222	3,229	3,187	3,213	3,239	3,264	3,289
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	301	296	293	415	492	695	889	919	961	1,001	999	998	988	988	987	981	976	970	965
Oregon	983	1,146	1,143	1,141	1,506	1,731	2,303	2,920	3,009	3,149	3,274	3,250	3,239	3,202	3,193	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,109**	**5,817**	**5,888**	**5,909**	**7,438**	**8,472**	**10,842**	**13,353**	**13,775**	**14,323**	**14,872**	**14,972**	**14,988**	**14,861**	**14,878**	**14,850**	**15,745**	**15,814**	**15,894**	**15,975**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	13%	14%	18%	21%	22%	22%	23%	23%	23%	22%	22%	22%	23%	23%	23%	22%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

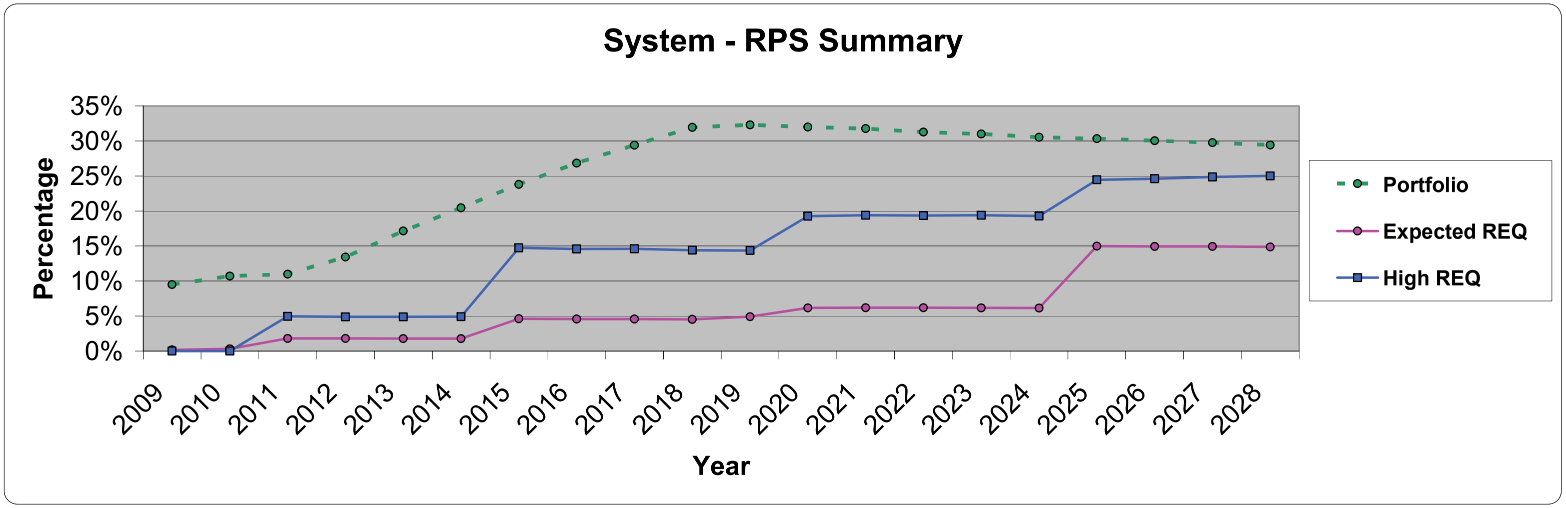

System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 11

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,556	8,739	12,055	16,033	21,039	27,026	33,987	41,869	50,530	60,015	69,725	79,466	89,221	98,925	108,645	118,359	122,836	127,291	131,710	136,117
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	495	500	802	1,157	1,276	1,389	1,689	1,974	1,904	1,680	1,669	1,650	1,634	1,625	1,611	1,591	1,573	1,555
Oregon	1,380	2,534	3,034	3,922	5,370	7,328	8,333	9,848	11,776	14,183	16,681	18,348	19,963	21,518	23,032	24,499	25,061	25,544	25,937	26,241
Cumulative Surplus Credit Bank Balance	**6,936**	**11,576**	**15,584**	**20,455**	**27,211**	**35,511**	**43,596**	**53,106**	**63,995**	**76,172**	**88,310**	**99,494**	**110,852**	**122,094**	**133,310**	**144,483**	**149,508**	**154,426**	**159,220**	**163,913**
Adjusted Qualifying Renewables																				
Utah	2,956	3,183	3,316	3,978	5,006	5,987	6,961	7,882	8,661	9,485	9,710	9,741	9,755	9,704	9,719	9,714	9,735	9,756	9,777	9,798
Other (ID,WY)	826	1,032	1,096	1,474	2,027	2,580	3,139	3,679	4,132	4,592	4,719	4,755	4,768	4,738	4,750	4,702	4,745	4,787	4,828	4,869
California	88	176	185	194	204	213	236	273	303	336	344	341	341	341	345	348	352	354	357	360
Washington	265	303	313	430	616	786	983	1,149	1,288	1,438	1,475	1,473	1,472	1,462	1,462	1,461	1,455	1,450	1,444	1,439
Oregon	986	1,154	1,201	1,596	2,168	2,690	3,233	3,759	4,195	4,685	4,798	4,763	4,748	4,709	4,696	4,678	4,623	4,569	4,516	4,463
Adjusted Qualifying Renewables	**5,122**	**5,848**	**6,110**	**7,671**	**10,020**	**12,256**	**14,552**	**16,742**	**18,578**	**20,535**	**21,047**	**21,072**	**21,084**	**20,955**	**20,972**	**20,903**	**20,910**	**20,915**	**20,922**	**20,929**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	20%	24%	27%	29%	32%	32%	32%	32%	31%	31%	31%	30%	30%	30%	29%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

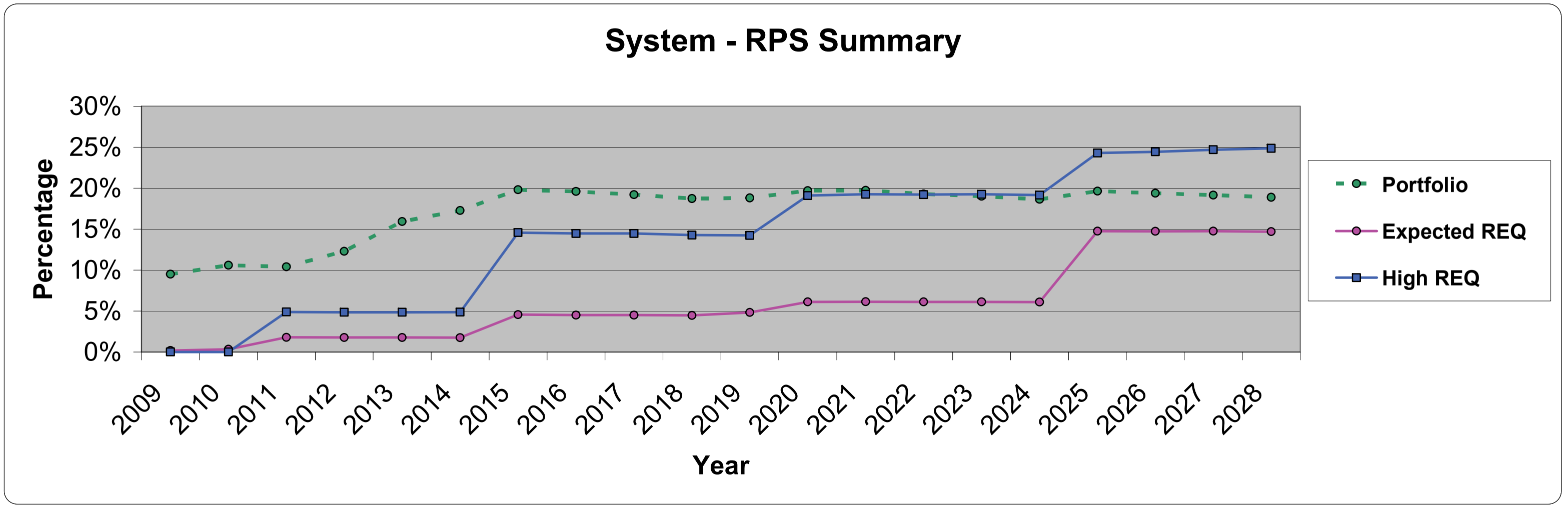


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 12

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,560	8,742	11,973	15,766	20,636	26,036	32,288	38,650	45,037	51,435	58,004	64,776	71,667	78,507	85,362	92,213	92,981	93,639	94,168	94,594
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	478	448	738	1,017	1,018	943	949	938	677	439	461	445	411	385	352	313	276	238
Oregon	1,382	2,536	2,977	3,739	5,083	6,661	7,129	7,606	8,027	8,419	8,841	8,429	7,988	7,446	6,822	6,099	4,294	2,366	301	-
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,429**	**19,953**	**26,457**	**33,715**	**40,435**	**47,199**	**54,013**	**60,792**	**67,523**	**73,644**	**80,116**	**86,398**	**92,596**	**98,697**	**97,627**	**96,318**	**94,745**	**94,832**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,793	4,870	5,401	6,252	6,362	6,387	6,398	6,568	6,772	6,891	6,840	6,855	6,850	6,871	6,892	6,913	6,934
Other (ID,WY)	828	1,031	1,049	1,371	1,950	2,245	2,732	2,804	2,818	2,813	2,905	3,028	3,096	3,065	3,073	3,030	3,055	3,079	3,103	3,126
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	266	303	298	396	591	679	853	872	873	875	901	931	949	939	939	938	932	927	921	916
Oregon	989	1,154	1,149	1,484	2,086	2,341	2,814	2,865	2,860	2,870	2,954	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**7,238**	**9,701**	**10,880**	**12,876**	**13,138**	**13,183**	**13,212**	**13,596**	**14,547**	**14,842**	**14,820**	**14,924**	**14,959**	**16,052**	**16,184**	**16,332**	**16,483**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	10%	11%	10%	12%	16%	17%	20%	20%	19%	19%	19%	20%	20%	19%	19%	19%	20%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

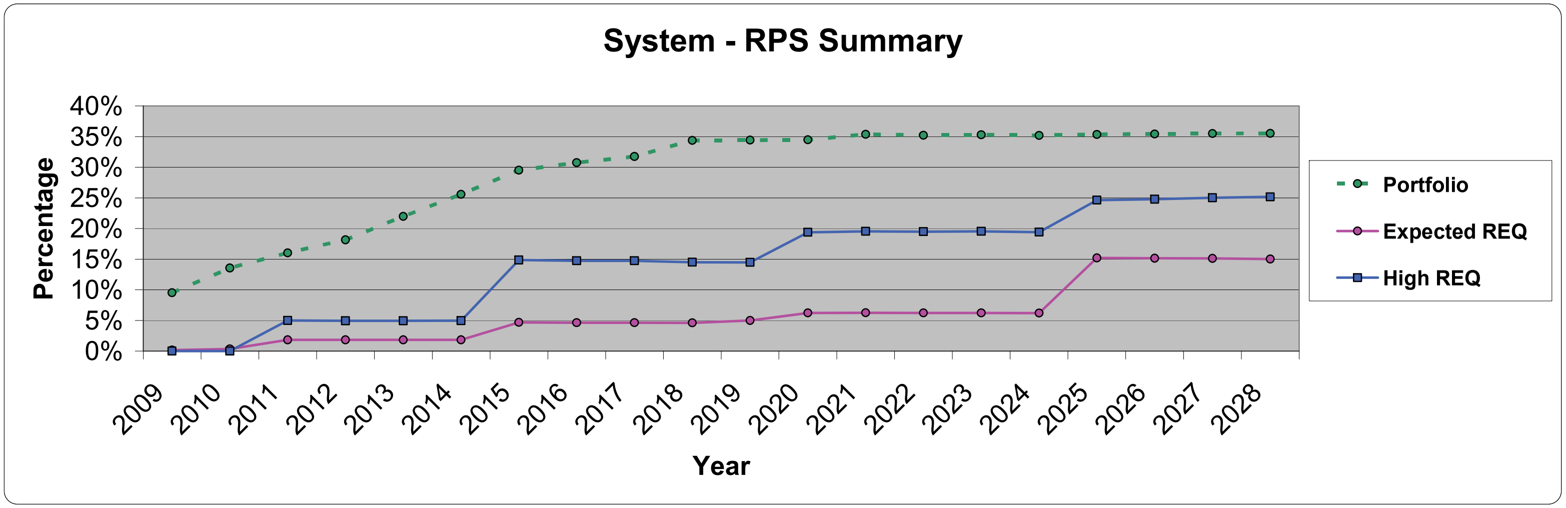


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = High, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 13

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,376	13,814	18,810	24,806	31,771	39,743	48,090	56,704	66,007	75,360	84,743	94,320	103,846	113,387	122,923	127,974	133,073	138,208	143,402
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	419	816	894	1,174	1,524	1,661	1,697	1,811	1,985	1,889	1,666	1,701	1,729	1,727	1,733	1,733	1,728	1,725	1,722
Oregon	1,382	2,925	4,115	5,633	7,698	10,266	11,982	13,909	15,972	18,459	20,961	22,739	24,605	26,447	28,285	30,111	31,198	32,253	33,268	34,243
Cumulative Surplus Credit Bank Balance	**6,942**	**12,720**	**18,744**	**25,337**	**33,678**	**43,561**	**53,386**	**63,695**	**74,487**	**86,451**	**98,210**	**109,148**	**120,626**	**132,023**	**143,399**	**154,767**	**160,905**	**167,054**	**173,201**	**179,367**
Adjusted Qualifying Renewables																				
Utah	2,960	3,816	4,437	4,997	5,995	6,965	7,972	8,347	8,614	9,302	9,353	9,384	9,577	9,526	9,541	9,536	9,557	9,577	9,598	9,620
Other (ID,WY)	828	1,379	1,719	2,043	2,583	3,137	3,719	3,947	4,105	4,486	4,513	4,547	4,664	4,634	4,645	4,598	4,640	4,680	4,721	4,760
California	88	176	185	194	203	235	277	292	301	329	330	327	334	332	332	332	328	323	319	315
Washington	266	419	518	616	796	965	1,167	1,234	1,279	1,405	1,410	1,407	1,439	1,430	1,429	1,428	1,423	1,417	1,412	1,407
Oregon	989	1,543	1,883	2,212	2,763	3,271	3,831	4,033	4,167	4,577	4,588	4,555	4,645	4,605	4,593	4,574	4,521	4,468	4,416	4,364
Adjusted Qualifying Renewables	**5,131**	**7,333**	**8,742**	**10,062**	**12,341**	**14,572**	**16,966**	**17,853**	**18,466**	**20,100**	**20,194**	**20,220**	**20,658**	**20,527**	**20,541**	**20,469**	**20,467**	**20,466**	**20,466**	**20,466**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	14%	16%	18%	22%	26%	30%	31%	32%	34%	34%	34%	35%	35%	35%	35%	35%	35%	36%	36%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

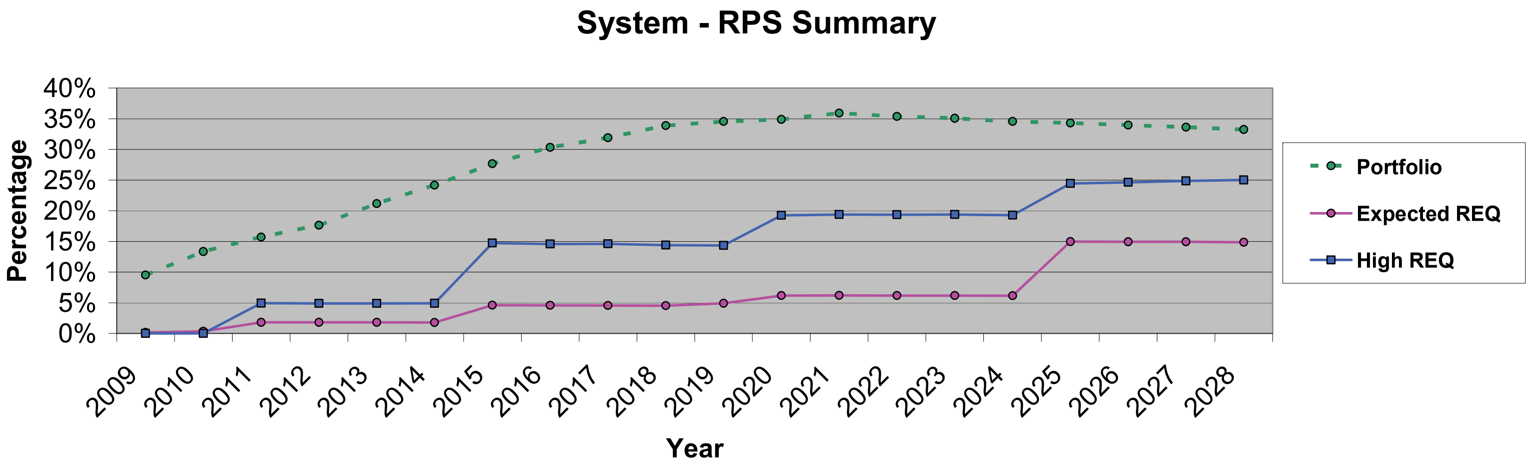


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 14

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,358	13,798	18,800	24,810	31,734	39,687	48,487	57,816	67,819	78,148	88,685	99,594	110,451	121,324	132,192	137,823	143,431	149,004	154,564
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	812	893	1,172	1,511	1,628	1,738	1,979	2,190	2,112	1,939	2,025	2,071	2,055	2,047	2,032	2,012	1,994	1,977
Oregon	1,382	2,914	4,098	5,605	7,657	10,171	11,762	13,818	16,138	18,850	21,711	23,842	26,127	28,352	30,534	32,670	33,895	35,035	36,078	37,025
Cumulative Surplus Credit Bank Balance	**6,942**	**12,687**	**18,708**	**25,298**	**33,640**	**43,416**	**53,078**	**64,044**	**75,932**	**88,859**	**101,970**	**114,465**	**127,745**	**140,874**	**153,913**	**166,909**	**173,750**	**180,478**	**187,076**	**193,566**
Adjusted Qualifying Renewables																				
Utah	2,960	3,798	4,440	5,002	6,010	6,924	7,953	8,800	9,328	10,004	10,328	10,537	10,909	10,858	10,873	10,868	10,888	10,909	10,930	10,952
Other (ID,WY)	828	1,369	1,720	2,046	2,591	3,113	3,708	4,208	4,517	4,891	5,076	5,218	5,441	5,412	5,425	5,375	5,425	5,474	5,523	5,571
California	88	176	185	194	204	233	276	310	330	357	369	373	387	385	386	386	381	376	371	366
Washington	266	415	519	617	799	957	1,164	1,317	1,410	1,533	1,588	1,618	1,683	1,673	1,673	1,672	1,666	1,661	1,655	1,650
Oregon	989	1,532	1,885	2,215	2,772	3,246	3,820	4,300	4,586	4,990	5,161	5,227	5,419	5,378	5,364	5,348	5,286	5,226	5,166	5,107
Adjusted Qualifying Renewables	**5,131**	**7,290**	**8,748**	**10,075**	**12,376**	**14,473**	**16,921**	**18,934**	**20,171**	**21,774**	**22,522**	**22,973**	**23,837**	**23,706**	**23,720**	**23,648**	**23,647**	**23,646**	**23,645**	**23,645**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	21%	24%	28%	30%	32%	34%	35%	35%	36%	35%	35%	35%	34%	34%	34%	33%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

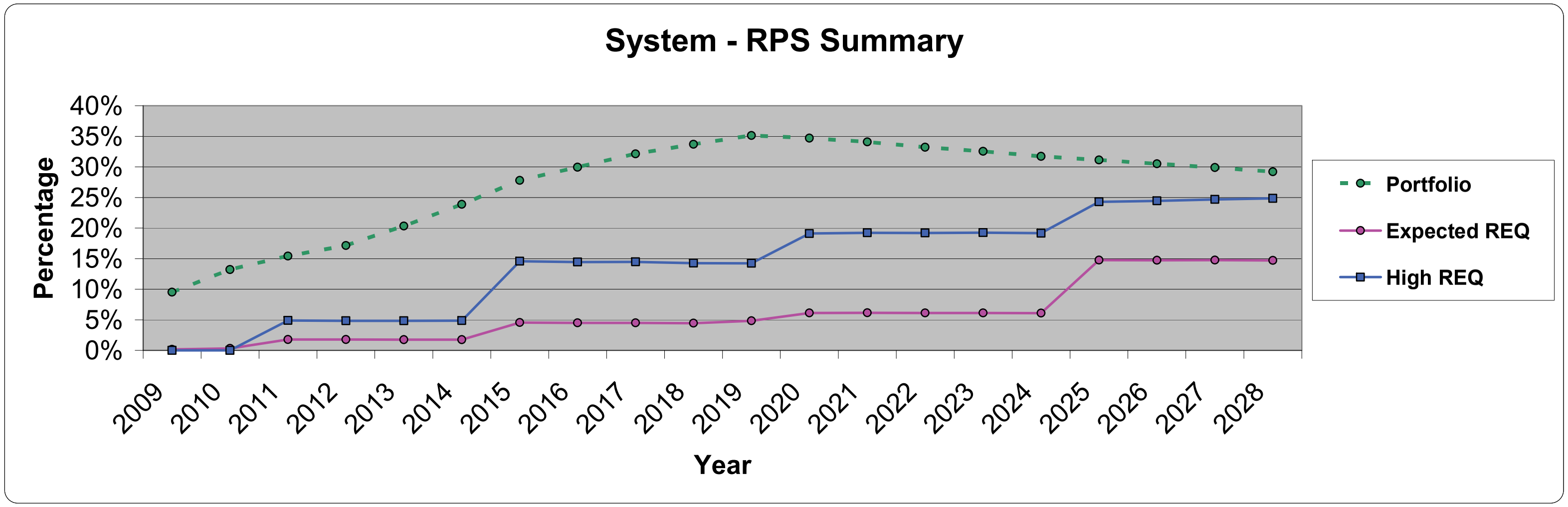


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 15

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,560	9,360	13,806	18,818	24,828	31,995	40,428	49,705	59,818	70,653	82,185	93,837	105,503	117,118	128,749	140,374	145,917	151,350	156,655	161,855
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	416	813	893	1,169	1,548	1,739	1,874	2,162	2,429	2,394	2,236	2,224	2,189	2,155	2,129	2,096	2,057	2,020	1,982
Oregon	1,382	2,915	4,095	5,595	7,624	10,252	12,009	14,201	16,808	19,808	23,145	25,577	27,910	30,140	32,281	34,330	35,271	36,061	36,686	37,145
Cumulative Surplus Credit Bank Balance	**6,942**	**12,691**	**18,714**	**25,306**	**33,621**	**43,796**	**54,176**	**65,779**	**78,788**	**92,891**	**107,725**	**121,650**	**135,638**	**149,448**	**163,185**	**176,834**	**183,284**	**189,468**	**195,360**	**200,982**
Adjusted Qualifying Renewables																				
Utah	2,960	3,800	4,446	5,012	6,009	7,168	8,433	9,277	10,113	10,835	11,532	11,652	11,666	11,615	11,630	11,625	11,646	11,667	11,688	11,709
Other (ID,WY)	828	1,371	1,723	2,052	2,591	3,253	3,983	4,482	4,971	5,370	5,771	5,867	5,883	5,854	5,868	5,817	5,872	5,926	5,979	6,031
California	88	176	185	194	204	243	296	329	361	390	417	417	417	416	416	416	412	419	428	436
Washington	266	416	520	619	799	1,002	1,252	1,404	1,553	1,685	1,808	1,822	1,821	1,811	1,811	1,810	1,804	1,799	1,793	1,788
Oregon	989	1,533	1,888	2,221	2,772	3,391	4,103	4,580	5,047	5,479	5,867	5,877	5,859	5,818	5,803	5,788	5,722	5,657	5,593	5,529
Adjusted Qualifying Renewables	**5,131**	**7,295**	**8,762**	**10,100**	**12,375**	**15,056**	**18,065**	**20,072**	**22,046**	**23,758**	**25,395**	**25,634**	**25,645**	**25,514**	**25,528**	**25,456**	**25,456**	**25,468**	**25,481**	**25,494**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	10%	13%	15%	17%	20%	24%	28%	30%	32%	34%	35%	35%	34%	33%	33%	32%	31%	31%	30%	29%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

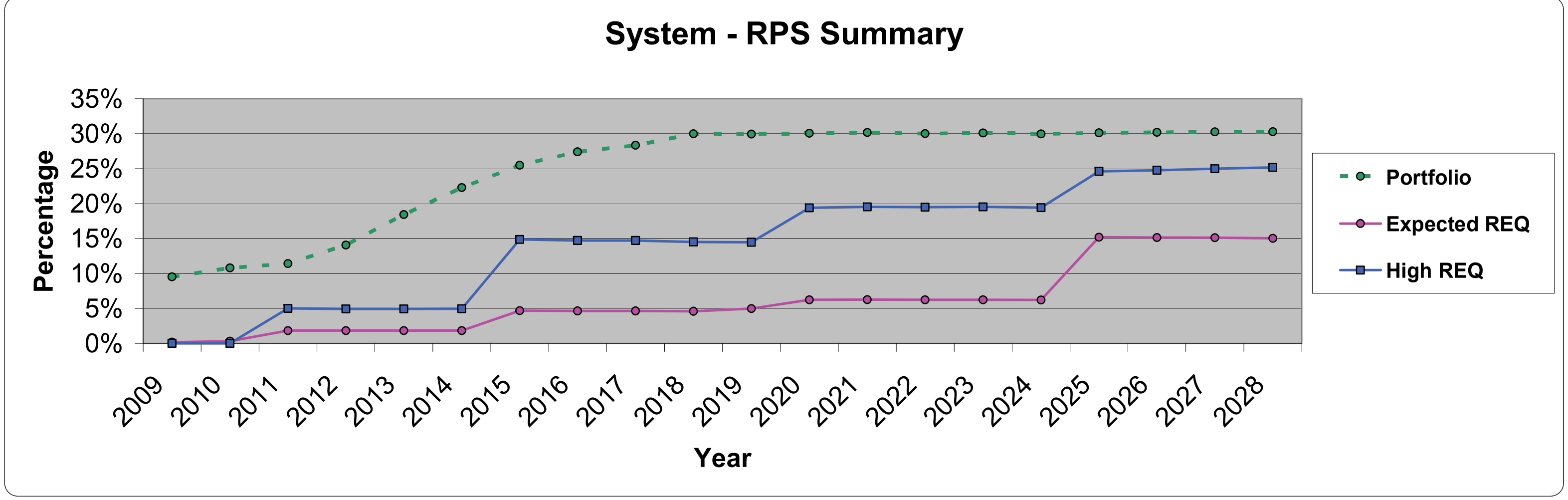


<u>Study Description</u>

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = High, Renewable Std = None 6/, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 16

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System **RPS Requirement - Energy GWh**																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	8,741	12,106	16,134	21,283	27,455	34,461	41,993	49,775	58,005	66,259	74,544	82,843	91,091	99,355	107,613	111,387	115,207	119,064	122,981
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	504	521	842	1,224	1,339	1,371	1,511	1,638	1,493	1,265	1,267	1,262	1,260	1,266	1,266	1,261	1,258	1,255
Oregon	1,382	2,535	3,073	4,005	5,561	7,658	8,802	10,250	11,825	13,681	15,538	16,675	17,799	18,900	19,998	21,082	21,435	21,763	22,058	22,320
Cumulative Surplus Credit Bank Balance	**6,942**	**11,579**	**15,683**	**20,660**	**27,686**	**36,337**	**44,602**	**53,614**	**63,110**	**73,324**	**83,290**	**92,484**	**101,909**	**111,254**	**120,612**	**129,962**	**134,087**	**138,231**	**142,380**	**146,556**
Adjusted Qualifying Renewables																				
Utah	2,959	3,181	3,365	4,028	5,148	6,172	7,005	7,532	7,782	8,230	8,254	8,285	8,299	8,248	8,263	8,258	8,279	8,300	8,321	8,342
Other (ID,WY)	828	1,031	1,124	1,502	2,106	2,685	3,164	3,478	3,624	3,868	3,878	3,908	3,918	3,888	3,897	3,852	3,886	3,919	3,951	3,983
California	88	176	185	194	203	212	238	259	268	286	286	302	302	301	300	299	299	297	296	295
Washington	266	303	322	439	642	820	991	1,085	1,127	1,209	1,209	1,207	1,206	1,197	1,196	1,195	1,190	1,184	1,179	1,173
Oregon	989	1,153	1,231	1,626	2,254	2,800	3,260	3,554	3,679	3,947	3,943	3,914	3,902	3,864	3,853	3,832	3,786	3,741	3,696	3,651
Adjusted Qualifying Renewables	**5,130**	**5,844**	**6,227**	**7,789**	**10,353**	**12,690**	**14,658**	**15,908**	**16,479**	**17,540**	**17,571**	**17,616**	**17,627**	**17,497**	**17,510**	**17,437**	**17,439**	**17,440**	**17,443**	**17,445**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	11%	11%	14%	18%	22%	25%	27%	28%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

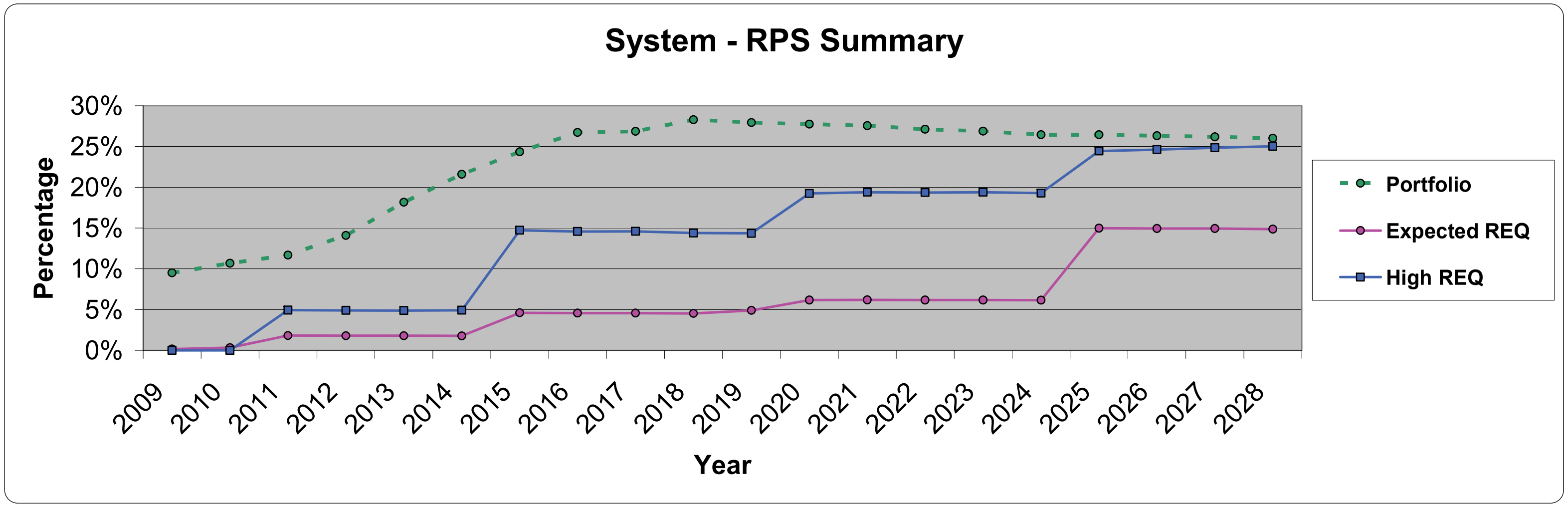


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 17

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,741	12,223	16,364	21,626	27,903	35,005	42,862	50,854	59,351	67,873	76,426	84,993	93,509	102,040	110,566	113,855	117,122	120,352	123,571
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	525	560	878	1,257	1,355	1,411	1,563	1,671	1,507	1,246	1,235	1,216	1,200	1,192	1,177	1,157	1,139	1,121
Oregon	1,382	2,535	3,137	4,123	5,725	7,855	8,943	10,444	11,979	13,806	15,606	16,580	17,505	18,370	19,197	19,973	19,852	19,659	19,383	19,024
Cumulative Surplus Credit Bank Balance	**6,942**	**11,579**	**15,885**	**21,048**	**28,230**	**37,014**	**45,303**	**54,717**	**64,395**	**74,828**	**84,986**	**94,252**	**103,732**	**113,095**	**122,436**	**131,731**	**134,884**	**137,938**	**140,874**	**143,716**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,482	4,141	5,262	6,277	7,102	7,857	7,991	8,498	8,522	8,553	8,567	8,516	8,531	8,526	8,547	8,567	8,589	8,610
Other (ID,WY)	828	1,031	1,188	1,565	2,170	2,745	3,219	3,665	3,745	4,023	4,033	4,064	4,074	4,044	4,054	4,008	4,044	4,078	4,112	4,146
California	88	176	185	194	204	213	242	272	276	296	296	336	339	341	345	348	352	354	357	360
Washington	266	303	344	460	662	839	1,009	1,145	1,166	1,258	1,258	1,256	1,255	1,245	1,245	1,244	1,238	1,233	1,227	1,222
Oregon	989	1,153	1,302	1,694	2,322	2,862	3,317	3,745	3,802	4,104	4,100	4,070	4,058	4,019	4,008	3,988	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,844**	**6,501**	**8,055**	**10,620**	**12,936**	**14,889**	**16,683**	**16,979**	**18,179**	**18,210**	**18,278**	**18,293**	**18,166**	**18,183**	**18,114**	**18,242**	**18,319**	**18,408**	**18,497**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	12%	14%	18%	22%	24%	27%	27%	28%	28%	28%	28%	27%	27%	26%	26%	26%	26%	26%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

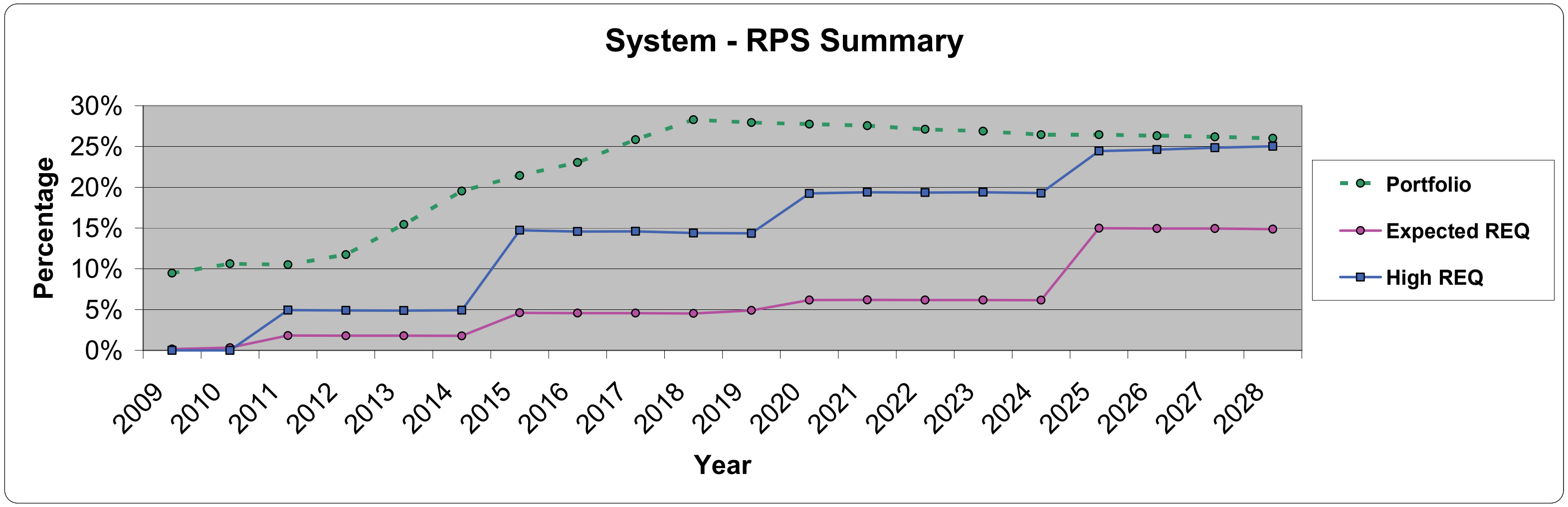


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 18

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,486	20,073	25,826	32,177	39,071	46,792	55,290	63,812	72,365	80,932	89,448	97,979	106,505	109,794	113,061	116,291	119,510
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	405	650	1,038	1,122	1,098	1,337	1,622	1,507	1,246	1,235	1,216	1,200	1,192	1,177	1,157	1,139	1,121
Oregon	1,376	2,519	2,952	3,591	4,787	6,605	7,250	8,184	9,561	11,387	13,188	14,162	15,086	15,952	16,778	17,555	17,434	17,240	16,964	16,605
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**19,481**	**25,510**	**33,468**	**40,549**	**48,353**	**57,690**	**68,299**	**78,507**	**87,773**	**97,253**	**106,616**	**115,956**	**125,251**	**128,404**	**131,458**	**134,395**	**137,237**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,566	4,587	5,753	6,352	6,894	7,721	8,498	8,522	8,553	8,567	8,516	8,531	8,526	8,547	8,567	8,589	8,610
Other (ID,WY)	822	1,022	1,034	1,244	1,791	2,446	2,789	3,110	3,589	4,023	4,033	4,064	4,074	4,044	4,054	4,008	4,044	4,078	4,112	4,146
California	88	176	185	194	204	213	223	233	266	296	296	336	339	341	345	348	352	354	357	360
Washington	264	300	293	355	539	743	872	969	1,116	1,258	1,258	1,256	1,255	1,245	1,245	1,244	1,238	1,233	1,227	1,222
Oregon	982	1,144	1,133	1,347	1,916	2,550	2,873	3,178	3,643	4,104	4,100	4,070	4,058	4,019	4,008	3,988	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**6,706**	**9,038**	**11,706**	**13,108**	**14,384**	**16,335**	**18,179**	**18,210**	**18,278**	**18,293**	**18,166**	**18,183**	**18,114**	**18,242**	**18,319**	**18,408**	**18,497**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	12%	15%	20%	21%	23%	26%	28%	28%	28%	28%	27%	27%	26%	26%	26%	26%	26%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

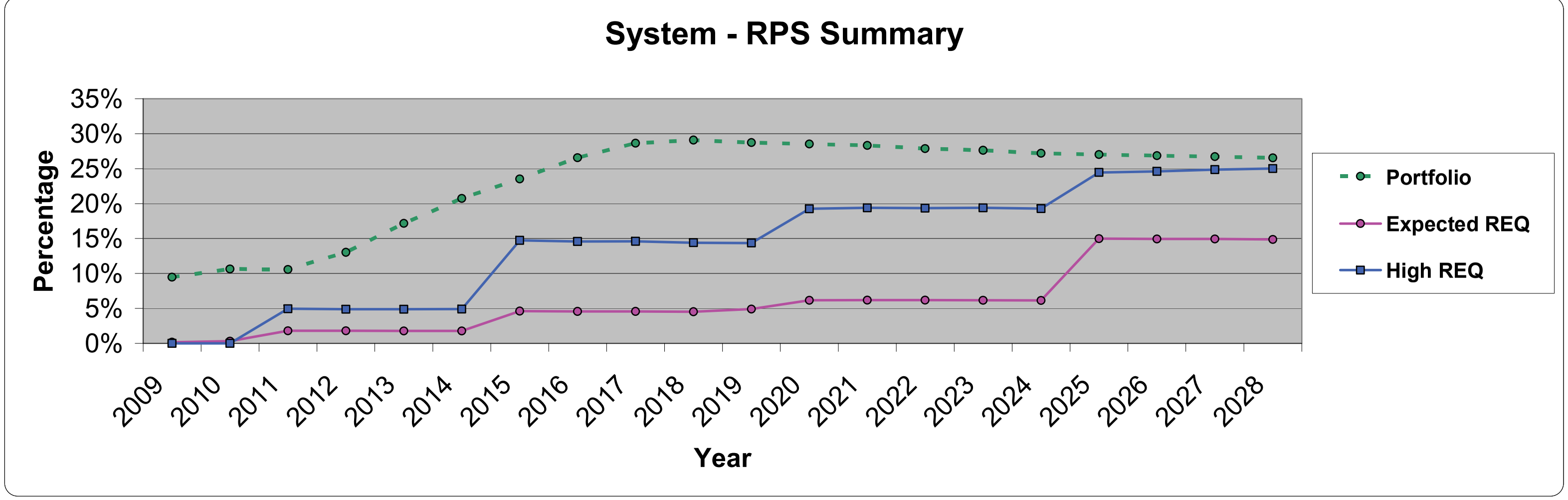


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 19

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,551	8,720	11,939	15,821	20,833	26,895	33,787	41,603	50,065	58,779	67,517	76,285	85,069	93,801	102,548	111,290	114,795	118,278	121,724	125,159
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	474	465	786	1,172	1,277	1,365	1,641	1,797	1,586	1,325	1,314	1,295	1,279	1,270	1,256	1,236	1,218	1,200
Oregon	1,376	2,522	2,964	3,794	5,245	7,247	8,211	9,688	11,499	13,453	15,380	16,480	17,530	18,521	19,472	20,375	20,378	20,307	20,153	19,915
Cumulative Surplus Credit Bank Balance	**6,927**	**11,542**	**15,377**	**20,080**	**26,864**	**35,314**	**43,276**	**52,655**	**63,205**	**74,028**	**84,483**	**94,091**	**103,912**	**113,617**	**123,299**	**132,935**	**136,428**	**139,821**	**143,096**	**146,274**
Adjusted Qualifying Renewables																				
Utah	2,950	3,169	3,219	3,882	5,012	6,062	6,892	7,815	8,462	8,714	8,738	8,769	8,783	8,732	8,747	8,742	8,763	8,783	8,805	8,826
Other (ID,WY)	823	1,024	1,043	1,421	2,030	2,622	3,099	3,641	4,017	4,147	4,158	4,189	4,200	4,170	4,180	4,135	4,171	4,207	4,242	4,277
California	88	176	185	194	204	213	234	270	295	305	305	336	339	341	345	348	352	354	357	360
Washington	264	300	296	413	617	800	970	1,137	1,252	1,297	1,298	1,295	1,294	1,285	1,284	1,283	1,278	1,272	1,267	1,262
Oregon	983	1,146	1,142	1,538	2,172	2,734	3,193	3,720	4,078	4,231	4,227	4,196	4,183	4,145	4,133	4,113	4,064	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,109**	**5,815**	**5,884**	**7,447**	**10,034**	**12,431**	**14,388**	**16,583**	**18,104**	**18,694**	**18,726**	**18,785**	**18,800**	**18,673**	**18,690**	**18,621**	**18,628**	**18,703**	**18,794**	**18,884**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	21%	24%	27%	29%	29%	29%	29%	28%	28%	28%	27%	27%	27%	27%	27%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

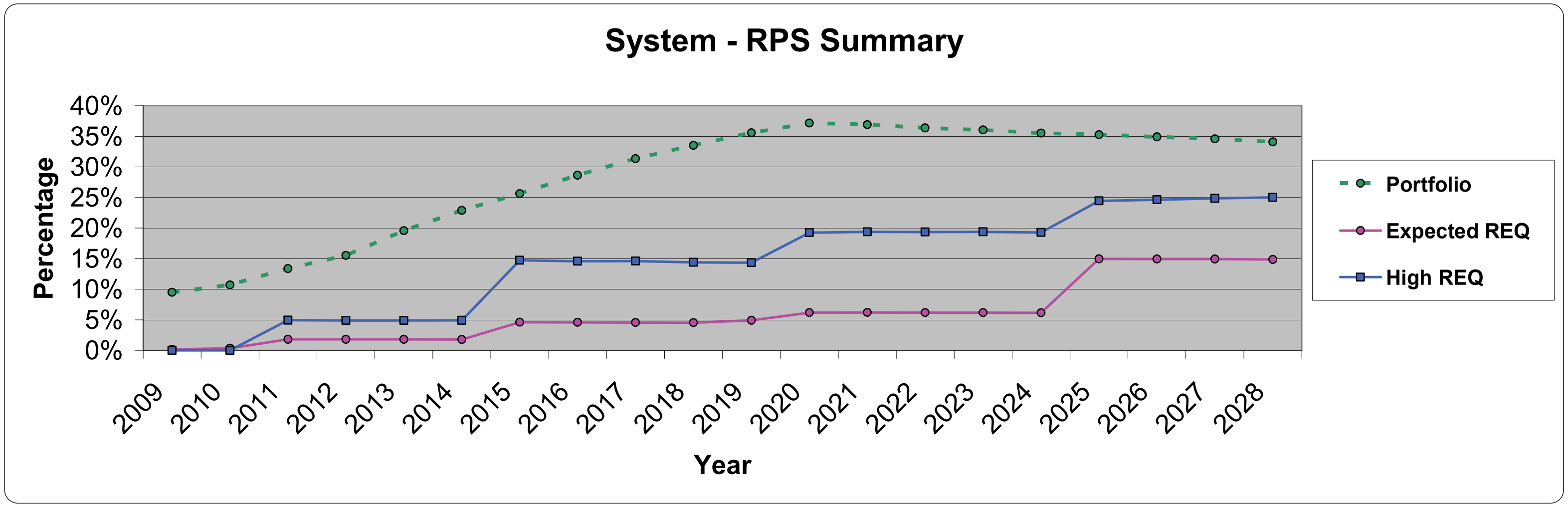


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 20

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,556	8,739	12,623	17,116	22,729	29,335	36,768	45,123	54,303	64,213	74,820	85,995	97,184	108,323	119,476	130,625	136,537	142,426	148,279	154,095
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	598	698	1,007	1,381	1,476	1,562	1,870	2,146	2,146	2,106	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,075
Oregon	1,380	2,534	3,380	4,579	6,392	8,718	10,001	11,795	14,027	16,684	19,709	22,211	24,660	27,048	29,392	31,692	33,079	34,378	35,579	36,669
Cumulative Surplus Credit Bank Balance	**6,936**	**11,576**	**16,601**	**22,393**	**30,128**	**39,434**	**48,245**	**58,479**	**70,200**	**83,043**	**96,674**	**110,312**	**124,037**	**137,545**	**151,026**	**164,466**	**171,750**	**178,918**	**185,955**	**192,839**
Adjusted Qualifying Renewables																				
Utah	2,956	3,183	3,884	4,493	5,613	6,607	7,433	8,354	9,180	9,910	10,607	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,207
Other (ID,WY)	826	1,032	1,411	1,762	2,368	2,933	3,409	3,951	4,432	4,837	5,237	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,726
California	88	176	185	194	204	220	255	292	324	353	380	398	398	397	397	397	392	387	382	376
Washington	265	303	417	524	726	899	1,069	1,235	1,383	1,516	1,639	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,696
Oregon	986	1,154	1,546	1,907	2,533	3,058	3,512	4,037	4,499	4,935	5,324	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,249
Adjusted Qualifying Renewables	**5,122**	**5,847**	**7,443**	**8,881**	**11,443**	**13,717**	**15,679**	**17,870**	**19,817**	**21,550**	**23,187**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,255**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	16%	20%	23%	26%	29%	31%	34%	36%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

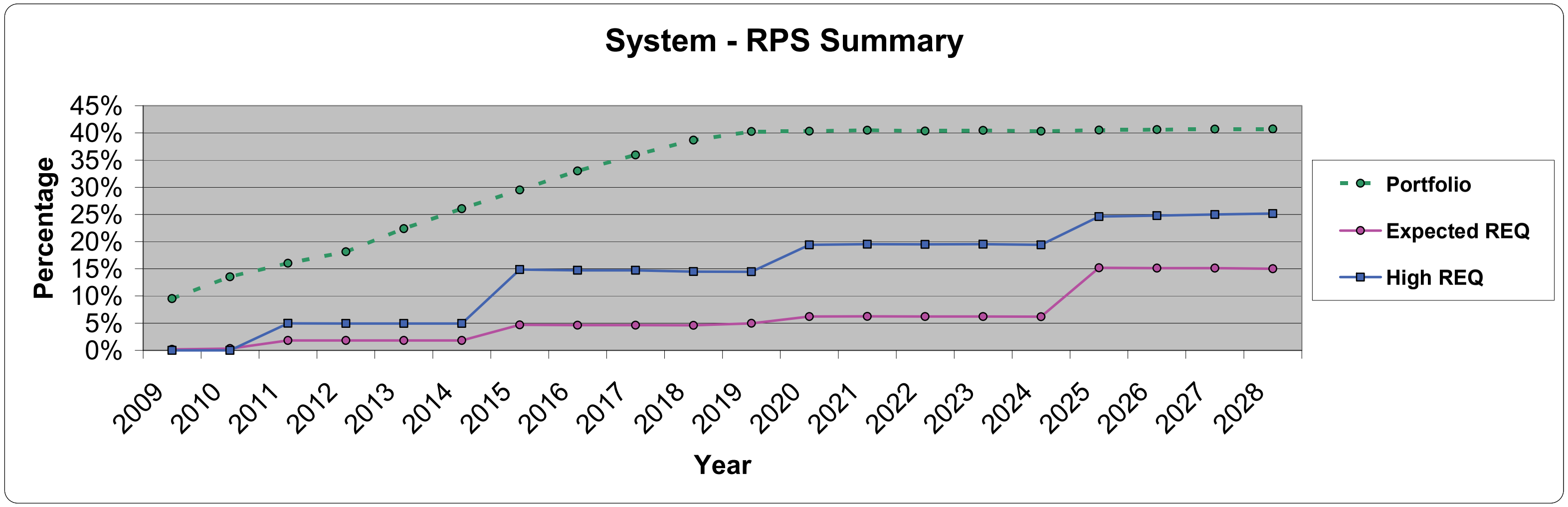


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 21

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,376	13,813	18,809	24,903	31,980	39,953	48,848	58,484	68,842	79,628	90,445	101,276	112,056	122,852	133,642	139,948	146,300	152,689	159,138
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	419	816	893	1,192	1,562	1,681	1,797	2,098	2,365	2,343	2,189	2,192	2,187	2,185	2,191	2,191	2,186	2,183	2,180
Oregon	1,382	2,925	4,114	5,632	7,757	10,391	12,107	14,356	17,019	20,127	23,470	26,083	28,678	31,249	33,812	36,367	38,176	39,944	41,666	43,340
Cumulative Surplus Credit Bank Balance	**6,942**	**12,720**	**18,742**	**25,335**	**33,852**	**43,934**	**53,741**	**65,001**	**77,602**	**91,333**	**105,441**	**118,717**	**132,146**	**145,492**	**158,849**	**172,200**	**180,314**	**188,431**	**196,538**	**204,659**
Adjusted Qualifying Renewables																				
Utah	2,960	3,816	4,437	4,996	6,094	7,077	7,972	8,895	9,637	10,357	10,786	10,817	10,831	10,780	10,795	10,790	10,811	10,832	10,853	10,874
Other (ID,WY)	828	1,379	1,718	2,043	2,638	3,201	3,719	4,262	4,695	5,094	5,340	5,381	5,396	5,366	5,380	5,330	5,380	5,428	5,476	5,523
California	88	176	185	194	205	239	277	314	342	371	387	384	384	382	383	382	377	373	368	363
Washington	266	419	518	616	814	985	1,167	1,334	1,466	1,598	1,672	1,669	1,668	1,659	1,658	1,657	1,652	1,646	1,641	1,636
Oregon	989	1,543	1,882	2,212	2,823	3,337	3,831	4,356	4,767	5,198	5,430	5,390	5,374	5,334	5,319	5,303	5,242	5,182	5,122	5,064
Adjusted Qualifying Renewables	**5,131**	**7,333**	**8,740**	**10,062**	**12,574**	**14,839**	**16,966**	**19,161**	**20,907**	**22,618**	**23,615**	**23,641**	**23,652**	**23,521**	**23,535**	**23,463**	**23,462**	**23,461**	**23,460**	**23,460**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	14%	16%	18%	22%	26%	30%	33%	36%	39%	40%	40%	40%	40%	40%	40%	41%	41%	41%	41%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

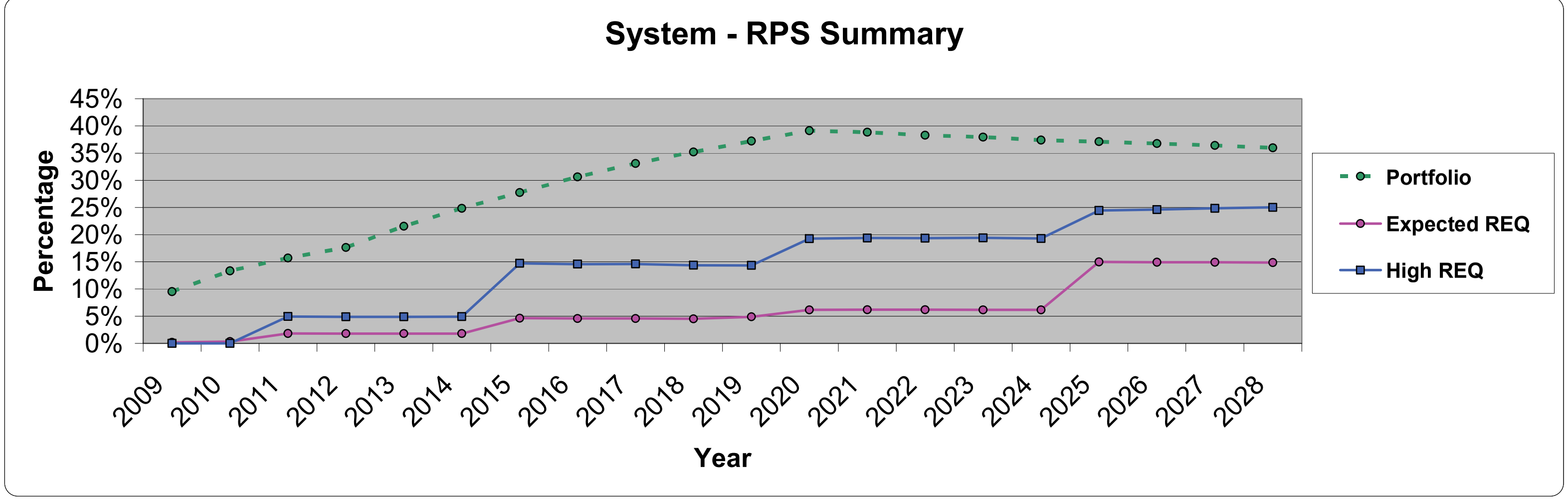


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 22

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,357	13,796	18,803	24,907	32,004	39,976	48,849	58,486	68,843	79,898	91,609	103,335	115,010	126,700	138,385	144,833	151,258	157,648	164,026
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	812	893	1,190	1,560	1,663	1,755	2,049	2,311	2,309	2,286	2,388	2,370	2,353	2,345	2,330	2,311	2,293	2,275
Oregon	1,382	2,913	4,097	5,607	7,716	10,332	11,935	14,033	16,533	19,454	22,741	25,556	28,316	31,016	33,670	36,282	37,977	39,581	41,085	42,488
Cumulative Surplus Credit Bank Balance	**6,942**	**12,685**	**18,705**	**25,304**	**33,813**	**43,896**	**53,574**	**64,637**	**77,068**	**90,609**	**104,948**	**119,451**	**134,040**	**148,395**	**162,724**	**177,012**	**185,140**	**193,150**	**201,025**	**208,788**
Adjusted Qualifying Renewables																				
Utah	2,960	3,797	4,440	5,007	6,104	7,096	7,972	8,873	9,637	10,358	11,054	11,711	11,726	11,675	11,690	11,685	11,705	11,726	11,747	11,769
Other (ID,WY)	828	1,369	1,720	2,049	2,644	3,212	3,719	4,250	4,695	5,095	5,495	5,902	5,918	5,889	5,903	5,852	5,907	5,962	6,015	6,068
California	88	176	185	194	205	240	277	313	342	371	398	419	419	418	419	418	413	408	402	397
Washington	266	415	518	618	816	989	1,167	1,330	1,466	1,598	1,721	1,833	1,832	1,822	1,822	1,821	1,815	1,810	1,804	1,799
Oregon	989	1,531	1,884	2,218	2,829	3,349	3,831	4,342	4,767	5,198	5,587	5,911	5,893	5,853	5,837	5,822	5,756	5,691	5,626	5,563
Adjusted Qualifying Renewables	**5,131**	**7,287**	**8,747**	**10,086**	**12,598**	**14,886**	**16,966**	**19,108**	**20,907**	**22,619**	**24,255**	**25,776**	**25,788**	**25,657**	**25,671**	**25,599**	**25,597**	**25,596**	**25,596**	**25,595**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	39%	39%	38%	38%	37%	37%	37%	36%	36%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

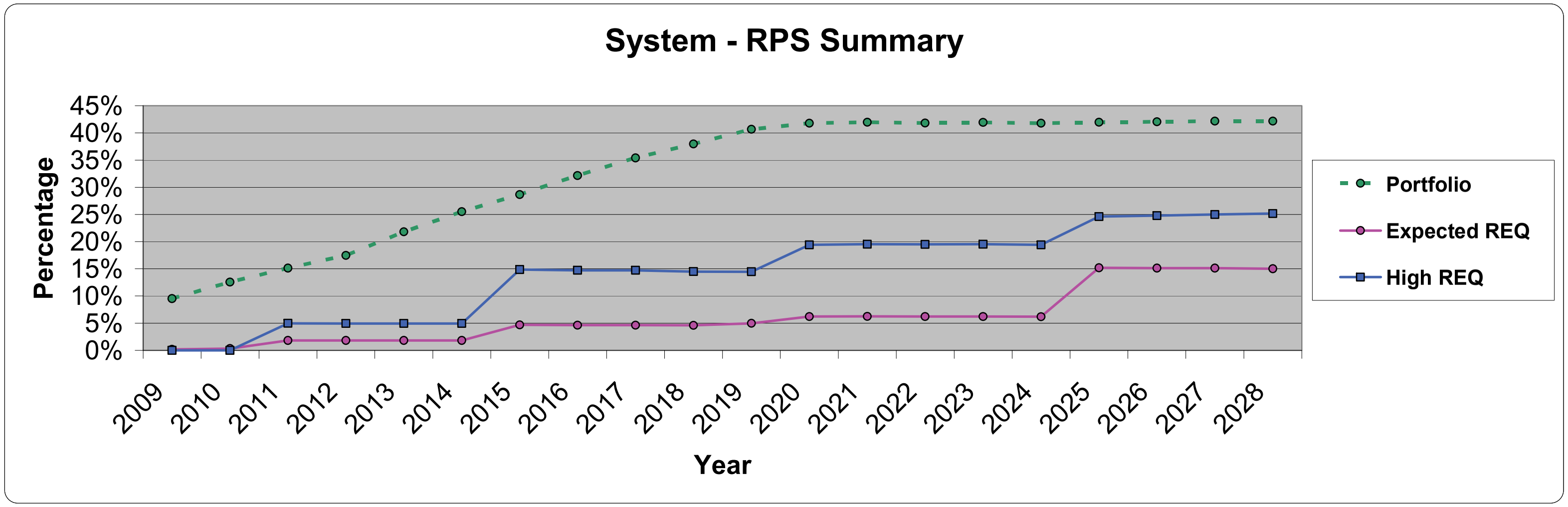


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 23

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,144	13,372	18,206	24,161	31,107	38,875	47,564	57,068	67,255	78,140	89,315	100,505	111,644	122,797	133,946	140,605	147,311	154,053	160,856
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	376	735	825	1,136	1,513	1,620	1,722	2,036	2,310	2,331	2,273	2,322	2,318	2,316	2,322	2,321	2,315	2,312	2,309
Oregon	1,382	2,783	3,845	5,264	7,305	9,862	11,457	13,585	16,170	19,178	22,579	25,401	28,204	30,983	33,754	36,517	38,528	40,498	42,419	44,290
Cumulative Surplus Credit Bank Balance	**6,942**	**12,303**	**17,952**	**24,295**	**32,603**	**42,481**	**51,951**	**62,871**	**75,274**	**88,743**	**103,050**	**116,989**	**131,032**	**144,944**	**158,866**	**172,784**	**181,453**	**190,124**	**198,784**	**207,455**
Adjusted Qualifying Renewables																				
Utah	2,959	3,585	4,228	4,833	5,955	6,946	7,768	8,689	9,503	10,188	10,885	11,175	11,190	11,138	11,154	11,149	11,164	11,185	11,206	11,228
Other (ID,WY)	828	1,252	1,602	1,952	2,560	3,126	3,601	4,144	4,619	4,997	5,397	5,590	5,605	5,576	5,589	5,539	5,588	5,639	5,689	5,739
California	88	176	185	194	203	234	269	305	337	364	391	398	398	397	397	397	391	386	381	376
Washington	266	376	480	586	789	961	1,130	1,297	1,442	1,567	1,690	1,735	1,734	1,724	1,724	1,723	1,716	1,711	1,705	1,700
Oregon	989	1,401	1,755	2,113	2,739	3,259	3,710	4,234	4,689	5,098	5,487	5,599	5,582	5,541	5,527	5,511	5,445	5,383	5,322	5,261
Adjusted Qualifying Renewables	**5,130**	**6,790**	**8,250**	**9,679**	**12,247**	**14,526**	**16,478**	**18,670**	**20,589**	**22,213**	**23,851**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,305**	**24,304**	**24,304**	**24,304**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	13%	15%	17%	22%	26%	29%	32%	35%	38%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

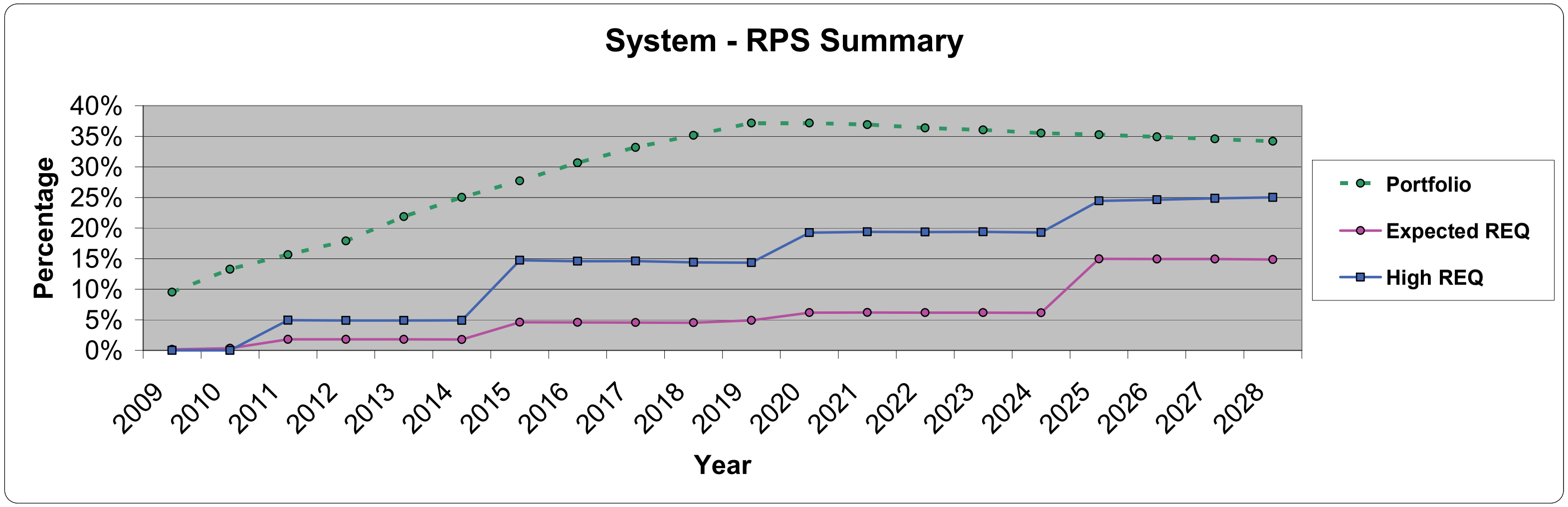


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 24

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,342	13,768	18,835	25,025	32,165	40,127	49,011	58,675	69,023	80,068	91,244	102,433	113,572	124,725	135,874	141,785	147,675	153,528	159,369
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	412	807	902	1,217	1,584	1,670	1,755	2,056	2,315	2,306	2,186	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,079
Oregon	1,382	2,904	4,079	5,626	7,787	10,429	12,025	14,130	16,647	19,561	22,843	25,346	27,794	30,182	32,527	34,826	36,213	37,512	38,714	39,817
Cumulative Surplus Credit Bank Balance	**6,942**	**12,659**	**18,654**	**25,363**	**34,029**	**44,178**	**53,822**	**64,896**	**77,378**	**90,899**	**105,217**	**118,775**	**132,420**	**145,928**	**159,409**	**172,849**	**180,133**	**187,302**	**194,338**	**201,266**
Adjusted Qualifying Renewables																				
Utah	2,959	3,783	4,426	5,067	6,190	7,140	7,962	8,884	9,664	10,348	11,045	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,233
Other (ID,WY)	828	1,361	1,712	2,083	2,692	3,237	3,713	4,256	4,711	5,089	5,490	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,741
California	88	176	185	194	209	242	277	313	343	370	398	398	398	397	397	397	392	387	382	377
Washington	266	412	516	629	832	997	1,166	1,332	1,471	1,596	1,719	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,701
Oregon	989	1,522	1,876	2,254	2,880	3,375	3,825	4,349	4,783	5,192	5,581	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,264
Adjusted Qualifying Renewables	**5,130**	**7,254**	**8,714**	**10,228**	**12,803**	**14,990**	**16,942**	**19,134**	**20,973**	**22,596**	**24,233**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,315**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

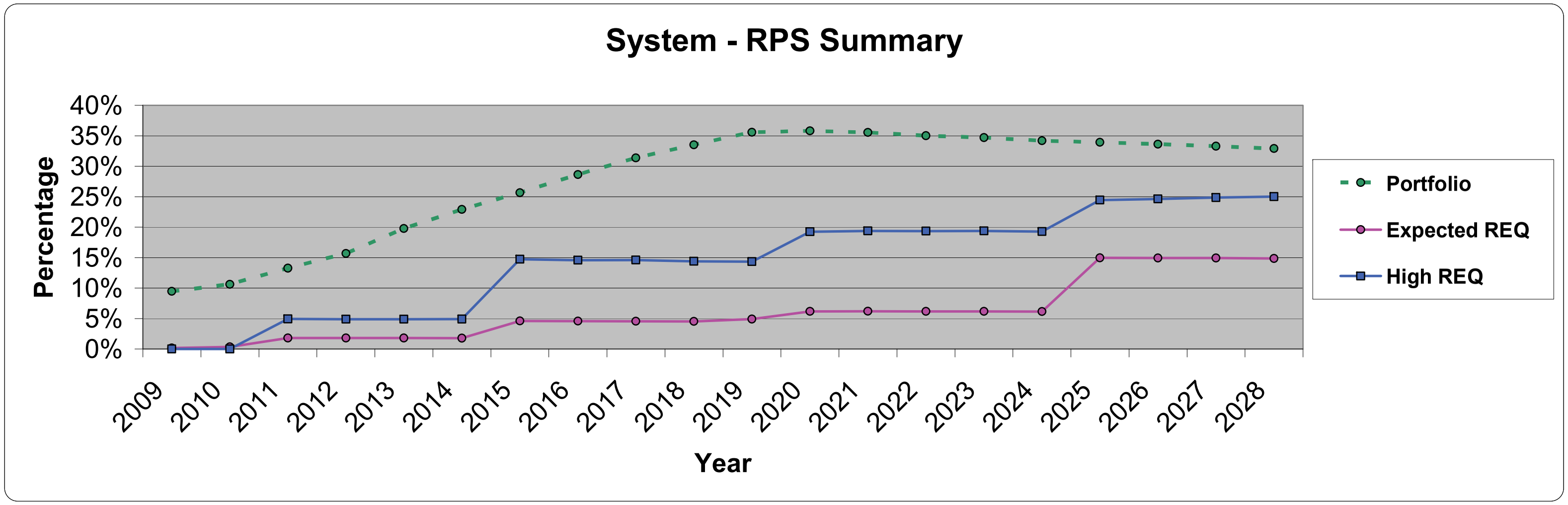


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 25

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	12,573	17,100	22,763	29,375	36,809	45,165	54,347	64,257	74,864	85,658	96,466	107,224	117,997	128,764	134,295	139,803	145,275	150,736
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	590	699	1,022	1,391	1,477	1,562	1,871	2,146	2,146	2,036	2,053	2,035	2,018	2,010	1,995	1,976	1,958	1,940
Oregon	1,376	2,519	3,349	4,569	6,412	8,741	10,025	11,820	14,053	16,710	19,735	22,015	24,242	26,409	28,533	30,611	31,779	32,862	33,848	34,740
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**16,512**	**22,369**	**30,197**	**39,507**	**48,311**	**58,547**	**70,271**	**83,113**	**96,744**	**109,709**	**122,762**	**135,668**	**148,548**	**161,386**	**168,069**	**174,641**	**181,082**	**187,416**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,857	4,528	5,662	6,612	7,434	8,356	9,181	9,910	10,607	10,794	10,809	10,758	10,773	10,768	10,788	10,809	10,830	10,852
Other (ID,WY)	822	1,022	1,397	1,781	2,396	2,936	3,410	3,952	4,432	4,837	5,237	5,368	5,382	5,353	5,366	5,317	5,366	5,415	5,463	5,510
California	88	176	185	194	204	220	255	292	324	353	380	383	383	381	382	382	377	372	367	362
Washington	264	300	412	531	735	900	1,069	1,236	1,383	1,516	1,639	1,665	1,664	1,655	1,654	1,653	1,648	1,642	1,637	1,631
Oregon	982	1,144	1,530	1,928	2,563	3,061	3,513	4,038	4,500	4,935	5,324	5,377	5,360	5,320	5,306	5,290	5,229	5,169	5,110	5,051
Adjusted Qualifying Renewables	**5,106**	**5,807**	**7,381**	**8,962**	**11,560**	**13,730**	**15,681**	**17,874**	**19,820**	**21,550**	**23,187**	**23,587**	**23,598**	**23,467**	**23,481**	**23,409**	**23,408**	**23,407**	**23,406**	**23,406**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	16%	20%	23%	26%	29%	31%	34%	36%	36%	36%	35%	35%	34%	34%	34%	33%	33%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

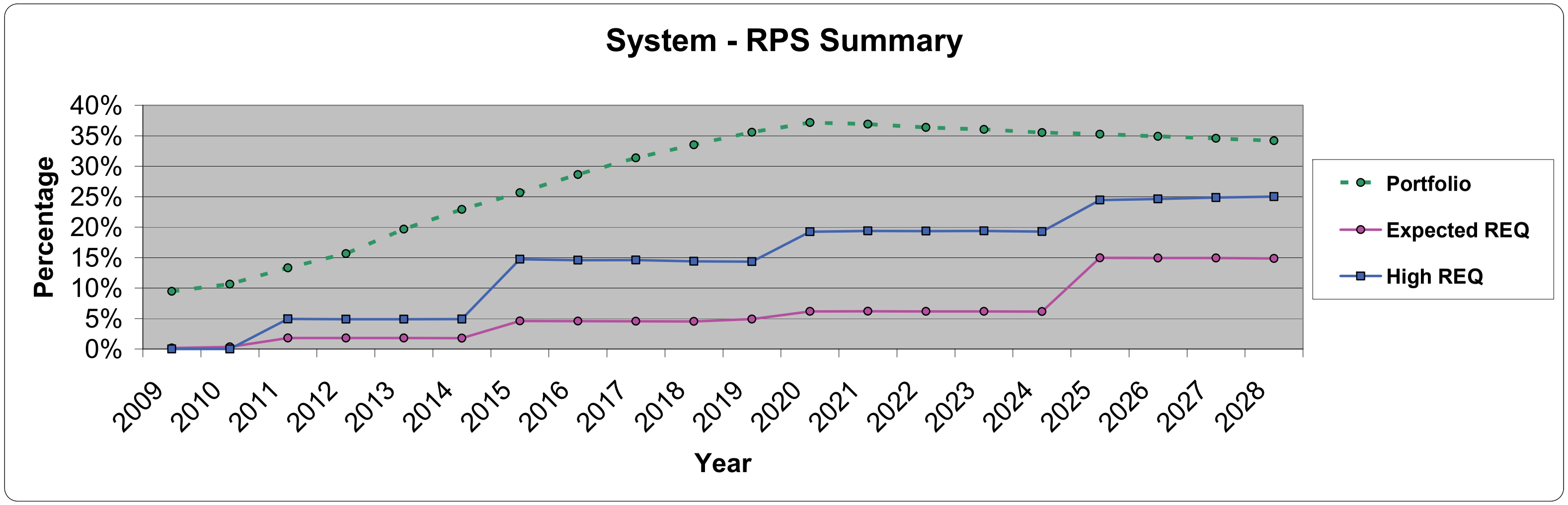


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 26

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,551	8,720	12,589	17,108	22,749	29,361	36,795	45,151	54,333	64,243	74,850	86,025	97,215	108,353	119,507	130,655	136,567	142,456	148,309	154,151
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	593	700	1,017	1,387	1,477	1,562	1,871	2,147	2,146	2,106	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,079
Oregon	1,376	2,522	3,359	4,574	6,404	8,733	10,017	11,812	14,045	16,702	19,727	22,229	24,678	27,066	29,410	31,710	33,096	34,396	35,597	36,701
Cumulative Surplus Credit Bank Balance	**6,927**	**11,542**	**16,541**	**22,381**	**30,170**	**39,481**	**48,289**	**58,525**	**70,249**	**83,092**	**96,722**	**110,360**	**124,085**	**137,593**	**151,074**	**164,514**	**171,798**	**178,967**	**186,003**	**192,931**
Adjusted Qualifying Renewables																				
Utah	2,950	3,169	3,869	4,518	5,641	6,612	7,434	8,356	9,182	9,910	10,607	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,233
Other (ID,WY)	823	1,024	1,403	1,776	2,384	2,936	3,410	3,952	4,433	4,837	5,237	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,741
California	88	176	185	194	204	220	255	292	324	353	380	398	398	397	397	397	392	387	382	377
Washington	264	300	414	529	732	900	1,069	1,236	1,383	1,516	1,639	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,701
Oregon	983	1,146	1,537	1,923	2,550	3,061	3,513	4,038	4,500	4,935	5,324	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,264
Adjusted Qualifying Renewables	**5,109**	**5,816**	**7,409**	**8,940**	**11,511**	**13,730**	**15,681**	**17,874**	**19,821**	**21,550**	**23,187**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,315**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	16%	20%	23%	26%	29%	31%	34%	36%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

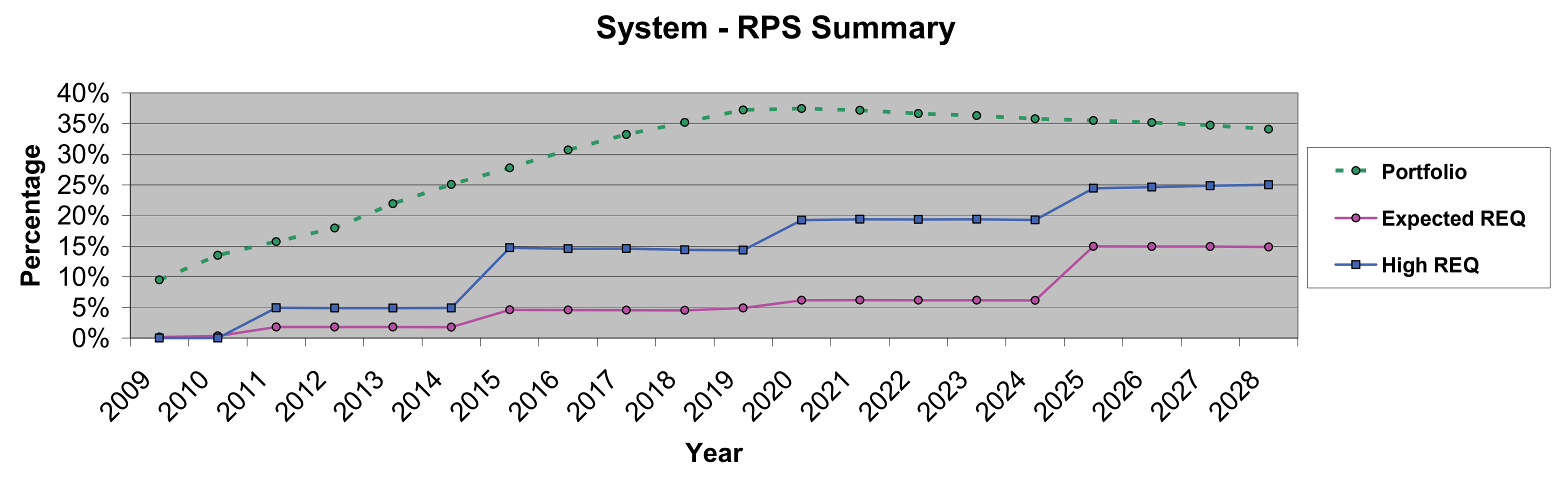


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 27

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,556	9,391	13,836	18,911	25,109	32,261	40,235	49,131	58,806	69,164	80,220	91,467	102,728	113,939	125,164	136,385	142,369	148,329	154,225	160,041
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	422	820	907	1,220	1,587	1,674	1,760	2,060	2,318	2,309	2,201	2,219	2,200	2,184	2,176	2,161	2,141	2,118	2,082
Oregon	1,380	2,934	4,121	5,673	7,838	10,487	12,091	14,203	16,725	19,646	22,934	25,479	27,969	30,399	32,785	35,126	36,554	37,894	39,120	40,209
Cumulative Surplus Credit Bank Balance	**6,936**	**12,746**	**18,776**	**25,491**	**34,166**	**44,336**	**54,000**	**65,094**	**77,591**	**91,129**	**105,463**	**119,146**	**132,916**	**146,538**	**160,133**	**173,687**	**181,084**	**188,364**	**195,463**	**202,333**
Adjusted Qualifying Renewables																				
Utah	2,956	3,834	4,445	5,076	6,197	7,152	7,974	8,896	9,675	10,358	11,055	11,247	11,262	11,211	11,226	11,221	11,241	11,261	11,254	11,207
Other (ID,WY)	826	1,389	1,723	2,088	2,696	3,244	3,720	4,263	4,717	5,095	5,496	5,632	5,647	5,618	5,632	5,581	5,633	5,684	5,718	5,726
California	88	176	185	194	209	242	277	314	344	371	398	401	401	399	400	400	395	389	383	376
Washington	265	422	519	631	833	999	1,168	1,334	1,473	1,598	1,721	1,748	1,747	1,738	1,737	1,736	1,730	1,725	1,714	1,696
Oregon	986	1,554	1,888	2,260	2,885	3,382	3,832	4,356	4,789	5,198	5,588	5,641	5,624	5,583	5,568	5,553	5,489	5,426	5,348	5,249
Adjusted Qualifying Renewables	**5,122**	**7,375**	**8,760**	**10,248**	**12,821**	**15,019**	**16,971**	**19,162**	**20,998**	**22,620**	**24,257**	**24,668**	**24,680**	**24,548**	**24,563**	**24,490**	**24,489**	**24,486**	**24,417**	**24,254**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	37%	37%	37%	36%	36%	36%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

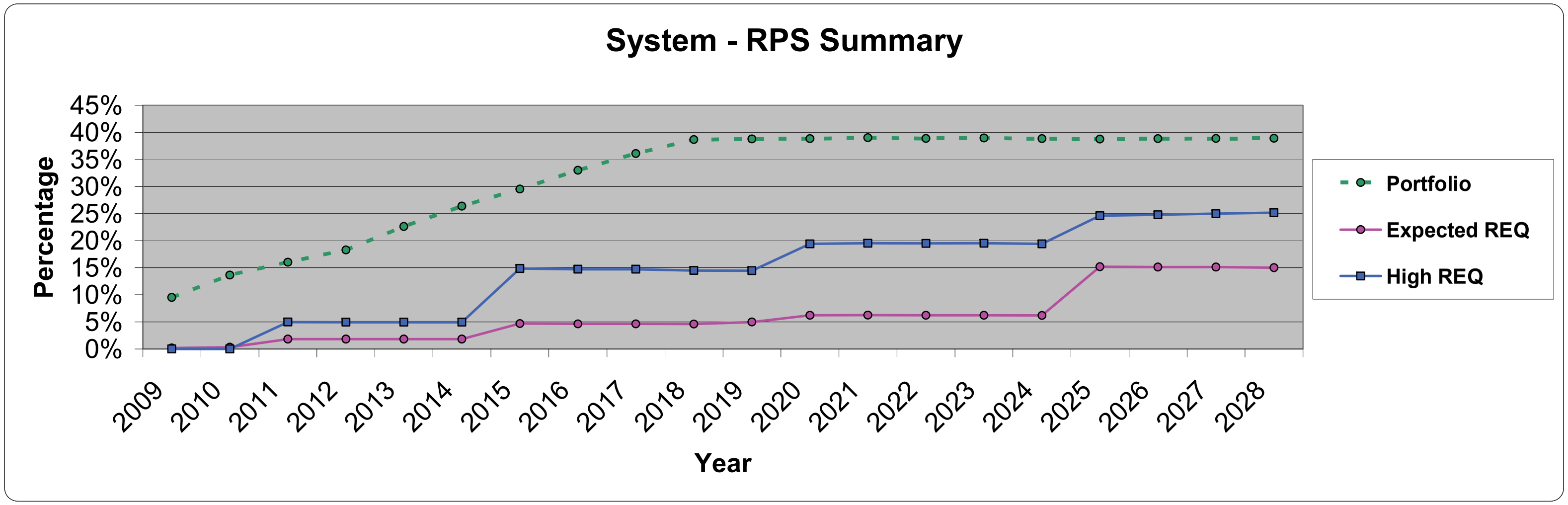


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 28

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,505	4,479	4,464	4,426
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	203	212	222	231	240	249	258	302	302	301	300	299	299	297	296	295
Washington	-	-	121	120	119	118	353	352	350	349	577	574	572	568	564	561	558	554	550	546
Oregon	-	-	693	693	698	703	2,115	2,106	2,104	2,090	2,087	2,777	2,778	2,763	2,756	2,748	3,434	3,413	3,401	3,389
Total RPS Requirement	88	176	999	1,007	1,020	1,034	2,690	2,689	2,694	2,688	2,922	3,653	3,652	3,632	3,620	3,607	8,796	8,744	8,711	8,656
Bank Balance																				
Utah	5,560	9,397	13,833	18,863	25,014	32,166	40,140	49,036	58,710	69,067	79,492	89,948	100,418	110,838	121,272	131,702	137,580	143,506	149,455	155,464
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	422	819	899	1,208	1,586	1,695	1,797	2,105	2,372	2,277	2,058	2,060	2,055	2,053	2,059	2,047	2,030	2,025	2,019
Oregon	1,382	2,938	4,126	5,665	7,824	10,503	12,220	14,469	17,154	20,262	23,393	25,795	28,181	30,542	32,896	35,242	36,805	38,331	39,804	41,233
Cumulative Surplus Credit Bank Balance	**6,942**	**12,757**	**18,779**	**25,427**	**34,046**	**44,255**	**54,055**	**65,302**	**77,969**	**91,700**	**105,162**	**117,801**	**130,659**	**143,435**	**156,221**	**169,002**	**176,431**	**183,867**	**191,284**	**198,716**
Adjusted Qualifying Renewables																				
Utah	2,959	3,837	4,436	5,030	6,152	7,152	7,974	8,895	9,674	10,357	10,425	10,456	10,470	10,419	10,434	10,429	10,384	10,405	10,412	10,434
Other (ID,WY)	828	1,391	1,718	2,062	2,670	3,244	3,720	4,262	4,717	5,094	5,132	5,171	5,185	5,156	5,168	5,119	5,128	5,174	5,211	5,256
California	88	176	185	194	207	242	277	314	344	371	373	369	369	368	368	368	361	356	351	346
Washington	266	422	518	622	825	999	1,168	1,334	1,473	1,598	1,606	1,603	1,603	1,593	1,592	1,592	1,574	1,569	1,561	1,555
Oregon	989	1,556	1,882	2,232	2,857	3,382	3,832	4,356	4,789	5,197	5,218	5,180	5,164	5,124	5,110	5,093	4,996	4,939	4,874	4,818
Adjusted Qualifying Renewables	**5,130**	**7,381**	**8,739**	**10,139**	**12,711**	**15,019**	**16,970**	**19,161**	**20,997**	**22,617**	**22,754**	**22,779**	**22,791**	**22,660**	**22,674**	**22,601**	**22,443**	**22,443**	**22,409**	**22,410**
System Load	53,963	54,123	54,572	55,451	56,177	56,946	57,500	58,058	58,165	58,495	58,672	58,637	58,419	58,306	58,183	58,179	57,922	57,782	57,636	57,623
Portfolio	10%	14%	16%	18%	23%	26%	30%	33%	36%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

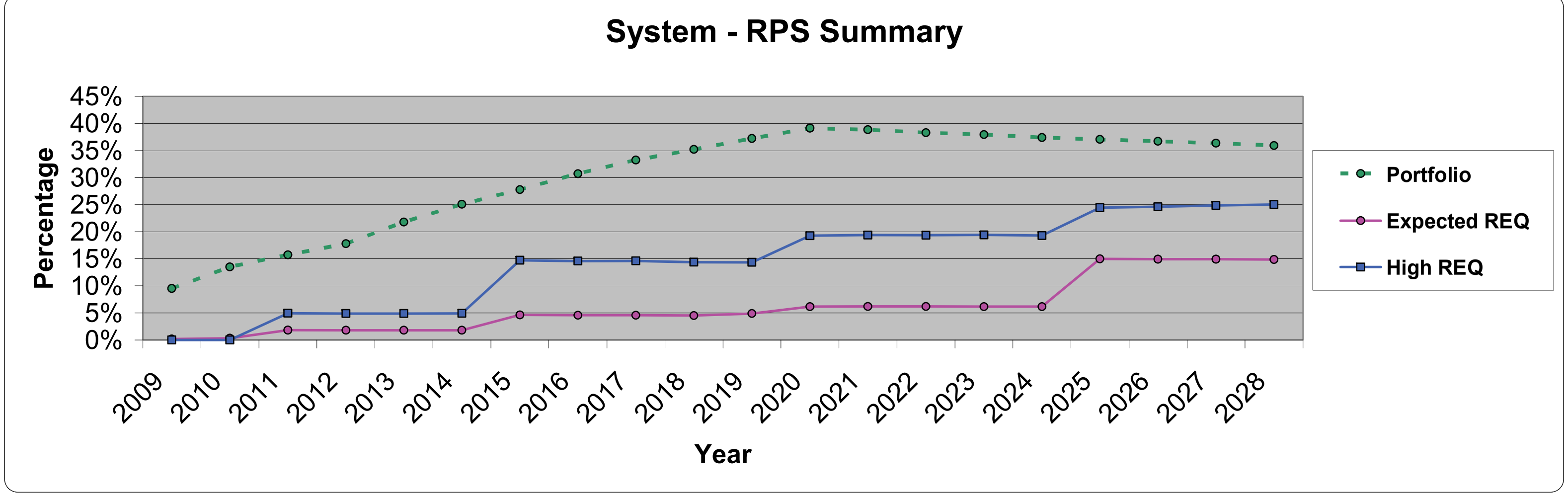


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - June 2008, Load Growth = Low, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 29

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,397	13,840	18,881	25,043	32,196	40,170	49,065	58,740	69,097	80,150	91,862	103,588	115,263	126,953	138,638	145,066	151,475	157,849	164,212
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	422	820	900	1,207	1,581	1,674	1,759	2,060	2,318	2,309	2,285	2,388	2,370	2,353	2,345	2,327	2,304	2,287	2,269
Oregon	1,382	2,938	4,124	5,655	7,798	10,448	12,051	14,163	16,686	19,606	22,892	25,708	28,468	31,167	33,822	36,433	38,117	39,712	41,207	42,602
Cumulative Surplus Credit Bank Balance	**6,942**	**12,757**	**18,784**	**25,436**	**34,049**	**44,224**	**53,895**	**64,988**	**77,486**	**91,021**	**105,352**	**119,855**	**134,444**	**148,800**	**163,128**	**177,416**	**185,510**	**193,491**	**201,343**	**209,083**
Adjusted Qualifying Renewables																				
Utah	2,960	3,837	4,443	5,041	6,162	7,152	7,974	8,896	9,675	10,357	11,054	11,711	11,726	11,675	11,690	11,685	11,686	11,710	11,732	11,754
Other (ID,WY)	828	1,391	1,722	2,068	2,676	3,244	3,720	4,263	4,717	5,094	5,495	5,902	5,918	5,889	5,903	5,852	5,896	5,952	6,006	6,059
California	88	176	185	194	208	242	277	314	344	371	398	419	419	418	419	418	412	407	402	397
Washington	266	422	519	624	827	999	1,168	1,334	1,473	1,598	1,720	1,833	1,832	1,822	1,822	1,821	1,812	1,807	1,802	1,796
Oregon	989	1,556	1,887	2,239	2,864	3,382	3,832	4,356	4,789	5,197	5,586	5,911	5,893	5,853	5,837	5,822	5,745	5,681	5,618	5,554
Adjusted Qualifying Renewables	**5,130**	**7,381**	**8,756**	**10,166**	**12,736**	**15,019**	**16,971**	**19,162**	**20,998**	**22,616**	**24,253**	**25,776**	**25,788**	**25,657**	**25,671**	**25,599**	**25,551**	**25,556**	**25,559**	**25,560**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	14%	16%	18%	22%	25%	28%	31%	33%	35%	37%	39%	39%	38%	38%	37%	37%	37%	36%	36%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

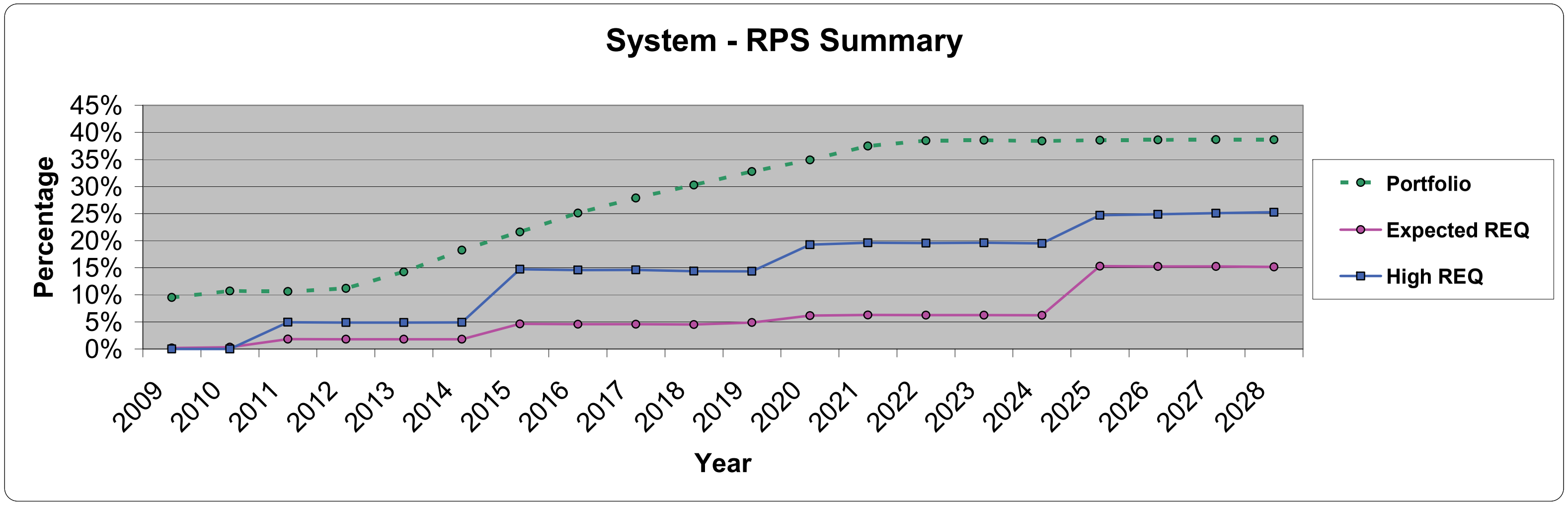


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 30

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,134	5,114	5,105	5,071
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	338	337	337	337	335	334	333
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	640	636	633	630	627	623	619
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,119	3,113	3,106	3,884	3,864	3,853	3,843
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,097	4,086	4,076	9,986	9,939	9,915	9,866
Bank Balance																				
Utah	5,560	8,745	11,975	15,410	19,691	25,112	31,510	38,945	47,207	56,245	66,089	76,636	87,869	99,365	110,877	122,383	128,773	135,206	141,668	148,185
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	385	570	921	1,070	1,205	1,535	1,819	1,847	1,852	2,086	2,251	2,302	2,308	2,307	2,302	2,299	2,295
Oregon	1,382	2,537	2,986	3,545	4,558	6,178	6,851	8,103	9,797	11,941	14,518	16,654	19,128	21,758	24,379	26,992	28,760	30,485	32,156	33,775
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**15,441**	**19,341**	**24,820**	**32,212**	**39,431**	**48,253**	**58,539**	**70,005**	**82,454**	**95,142**	**109,083**	**123,374**	**137,558**	**151,682**	**159,840**	**167,992**	**176,123**	**184,256**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,231	3,435	4,282	5,421	6,398	7,435	8,262	9,038	9,844	10,547	11,233	11,496	11,511	11,506	11,525	11,546	11,567	11,588
Other (ID,WY)	828	1,033	1,049	1,171	1,619	2,257	2,816	3,422	3,901	4,334	4,797	5,224	5,630	5,785	5,799	5,748	5,801	5,854	5,907	5,958
California	88	176	185	194	204	213	223	255	287	318	349	373	400	411	411	411	406	401	395	390
Washington	266	303	298	331	483	683	880	1,068	1,215	1,357	1,500	1,620	1,742	1,790	1,789	1,788	1,782	1,777	1,771	1,766
Oregon	989	1,155	1,149	1,267	1,733	2,353	2,901	3,496	3,960	4,422	4,877	5,232	5,607	5,749	5,734	5,718	5,652	5,588	5,525	5,462
Adjusted Qualifying Renewables	**5,131**	**5,852**	**5,911**	**6,397**	**8,320**	**10,927**	**13,217**	**15,676**	**17,626**	**19,468**	**21,367**	**22,996**	**24,612**	**25,230**	**25,244**	**25,172**	**25,167**	**25,166**	**25,165**	**25,164**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	65,679	65,596	65,504	65,544	65,302	65,191	65,074	65,105
Portfolio	10%	11%	11%	11%	14%	18%	22%	25%	28%	30%	33%	35%	37%	38%	39%	38%	39%	39%	39%	39%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

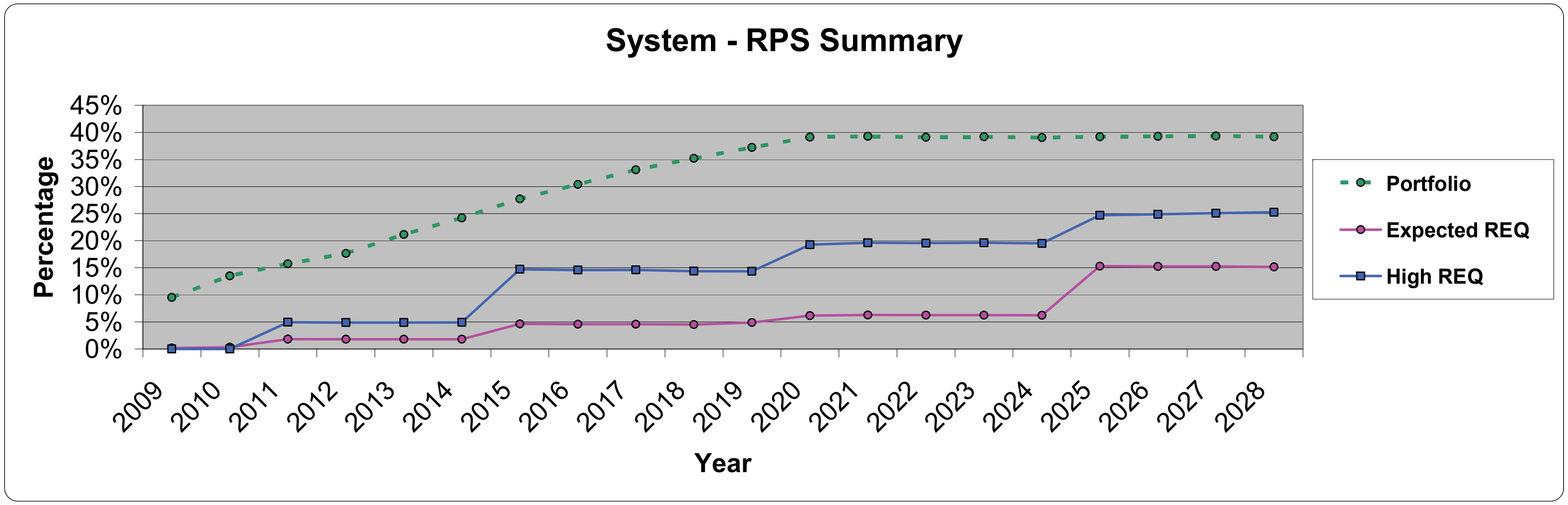


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45 (2013) to $179 (2030) 1/, Gas = Medium - June 2008, Load Growth = Medium (2009-2020)□Low (2021-2030), Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 31

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,134	5,114	5,105	5,071
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	338	337	337	337	335	334	333
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	640	636	633	630	627	623	619
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,119	3,113	3,106	3,884	3,864	3,853	3,843
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,097	4,086	4,076	9,986	9,939	9,915	9,866
Bank Balance																				
Utah	5,560	9,399	13,842	18,845	24,852	31,792	39,753	48,569	58,206	68,564	79,620	91,331	103,057	114,732	126,422	138,107	144,678	151,291	157,932	164,593
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	423	820	893	1,172	1,514	1,633	1,743	2,038	2,311	2,309	2,286	2,388	2,373	2,367	2,373	2,373	2,368	2,364	2,354
Oregon	1,382	2,939	4,125	5,633	7,683	10,206	11,802	13,867	16,368	19,289	22,576	25,392	28,152	30,885	33,610	36,326	38,198	40,025	41,798	43,497
Cumulative Surplus Credit Bank Balance	**6,942**	**12,761**	**18,787**	**25,371**	**33,708**	**43,512**	**53,188**	**64,179**	**76,612**	**90,164**	**104,505**	**119,008**	**133,597**	**147,991**	**162,399**	**176,806**	**185,249**	**193,684**	**202,094**	**210,444**
Adjusted Qualifying Renewables																				
Utah	2,960	3,839	4,443	5,003	6,007	6,940	7,961	8,816	9,637	10,358	11,055	11,711	11,726	11,675	11,690	11,685	11,705	11,726	11,746	11,732
Other (ID,WY)	828	1,392	1,722	2,047	2,589	3,123	3,712	4,217	4,695	5,095	5,496	5,902	5,918	5,889	5,903	5,852	5,907	5,962	6,014	6,045
California	88	176	185	194	204	234	277	310	342	371	398	419	419	418	419	418	413	408	402	396
Washington	266	423	519	617	798	960	1,165	1,320	1,466	1,598	1,721	1,833	1,832	1,822	1,822	1,821	1,815	1,810	1,804	1,792
Oregon	989	1,557	1,886	2,216	2,771	3,256	3,824	4,309	4,767	5,198	5,588	5,911	5,893	5,853	5,837	5,822	5,756	5,691	5,626	5,542
Adjusted Qualifying Renewables	**5,131**	**7,386**	**8,755**	**10,077**	**12,369**	**14,512**	**16,939**	**18,973**	**20,907**	**22,620**	**24,257**	**25,776**	**25,788**	**25,657**	**25,671**	**25,599**	**25,597**	**25,596**	**25,593**	**25,507**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	65,679	65,596	65,504	65,544	65,302	65,191	65,074	65,105
Portfolio	10%	14%	16%	18%	21%	24%	28%	30%	33%	35%	37%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

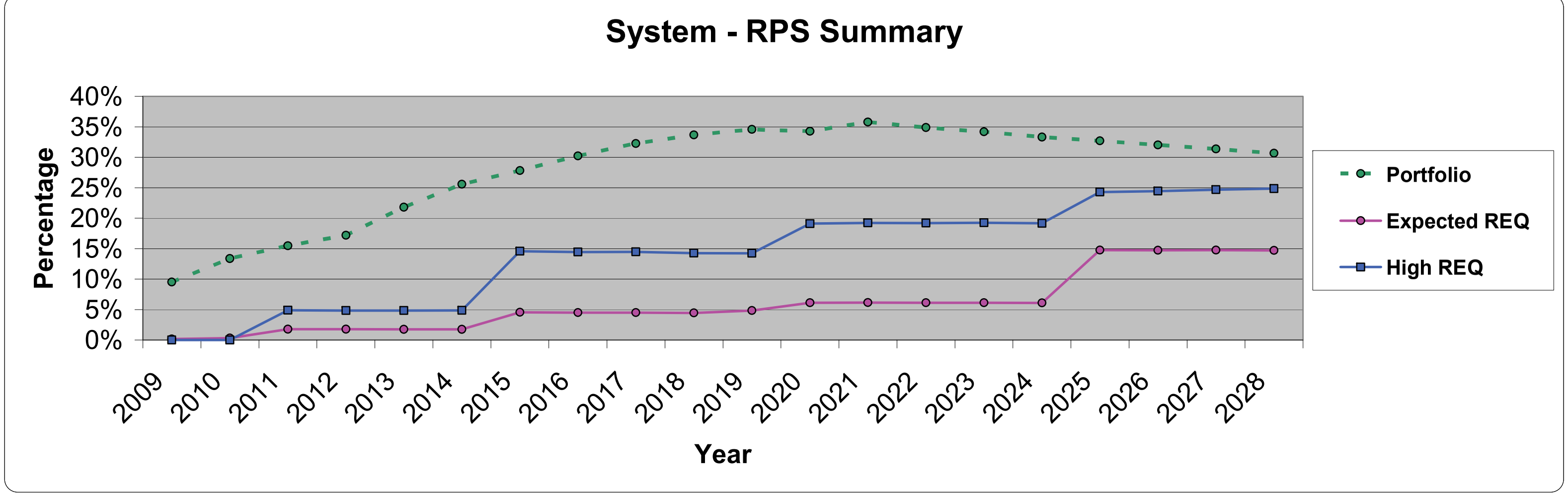


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45 (2013) to $179 (2030) 1/, Gas = High - June 2008, Load Growth = Medium (2009-2020)□Low (2021-2030), Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 33

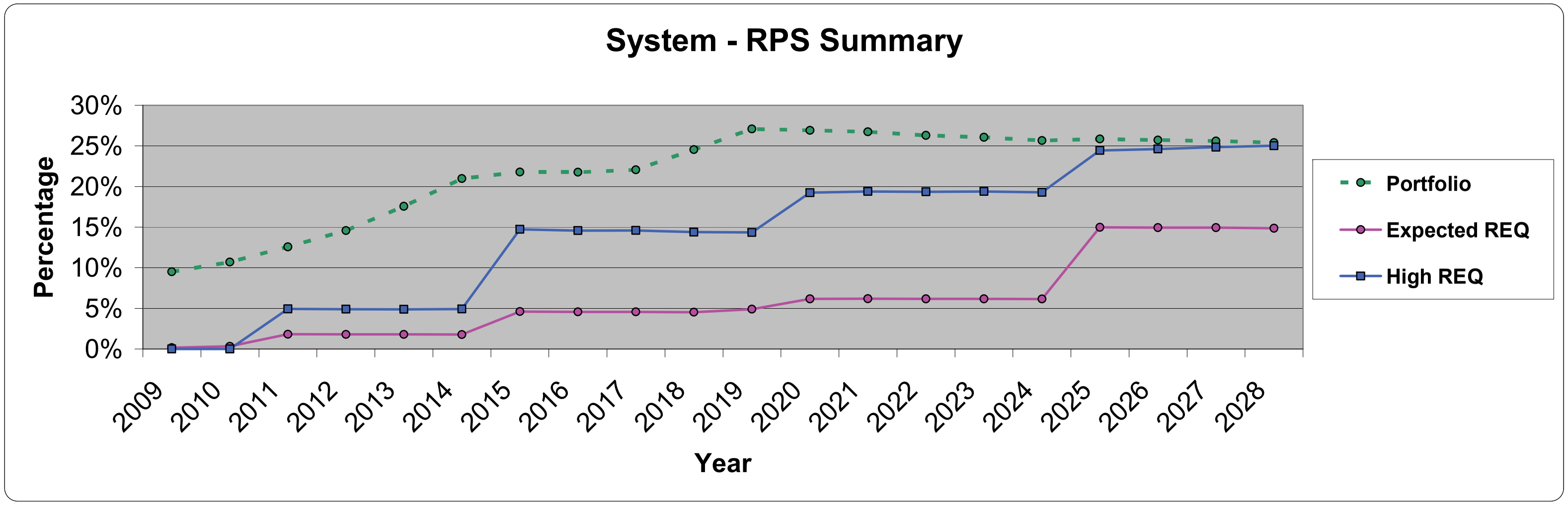
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,103	6,233	6,383	6,509
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	214	225	235	246	256	268	372	380	387	395	403	412	419	428	436
Washington	-	-	122	124	125	127	388	394	401	408	691	703	716	728	739	752	766	780	793	807
Oregon	-	-	708	722	742	763	2,346	2,388	2,439	2,478	2,531	3,445	3,525	3,588	3,662	3,738	4,781	4,867	4,968	5,071
Total RPS Requirement	88	176	1,015	1,040	1,072	1,104	2,958	3,017	3,086	3,143	3,489	4,519	4,621	4,703	4,797	4,893	12,063	12,300	12,571	12,823
Bank Balance																				
Utah	5,560	9,398	13,854	18,879	25,263	32,877	41,311	50,668	60,819	71,652	83,020	94,535	106,738	118,889	131,056	143,218	149,297	155,267	161,108	166,844
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	423	822	897	1,240	1,698	1,820	1,888	2,183	2,435	2,364	2,181	2,297	2,385	2,351	2,325	2,292	2,253	2,215	2,178
Oregon	1,382	2,938	4,125	5,632	7,887	10,780	12,538	14,776	17,406	20,405	23,645	25,998	28,643	31,184	33,635	35,996	37,245	38,340	39,267	40,025
Cumulative Surplus Credit Bank Balance	**6,941**	**12,759**	**18,800**	**25,408**	**34,390**	**45,355**	**55,670**	**67,332**	**80,408**	**94,493**	**109,029**	**122,714**	**137,678**	**152,458**	**167,042**	**181,539**	**188,833**	**195,859**	**202,590**	**209,047**
Adjusted Qualifying Renewables																				
Utah	2,959	3,838	4,456	5,025	6,384	7,614	8,435	9,356	10,151	10,833	11,368	11,515	12,203	12,151	12,167	12,162	12,182	12,203	12,224	12,246
Other (ID,WY)	828	1,391	1,729	2,060	2,801	3,507	3,984	4,528	4,993	5,369	5,676	5,788	6,196	6,167	6,183	6,131	6,189	6,246	6,302	6,358
California	88	176	185	194	217	261	296	332	363	390	411	412	438	437	438	437	432	426	428	436
Washington	266	423	521	622	867	1,083	1,252	1,418	1,560	1,685	1,778	1,797	1,919	1,909	1,909	1,908	1,902	1,897	1,891	1,886
Oregon	988	1,556	1,894	2,229	2,997	3,656	4,104	4,627	5,069	5,478	5,771	5,797	6,170	6,129	6,113	6,099	6,030	5,962	5,895	5,829
Adjusted Qualifying Renewables	**5,130**	**7,384**	**8,785**	**10,130**	**13,267**	**16,120**	**18,070**	**20,261**	**22,136**	**23,754**	**25,003**	**25,309**	**26,926**	**26,795**	**26,809**	**26,736**	**26,735**	**26,734**	**26,740**	**26,754**
System Load	53,963	55,209	56,795	58,885	60,891	63,017	64,985	67,026	68,617	70,513	72,287	73,862	75,258	76,828	78,432	80,241	81,763	83,490	85,259	87,266
Portfolio	10%	13%	15%	17%	22%	26%	28%	30%	32%	34%	35%	34%	36%	35%	34%	33%	33%	32%	31%	31%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	4%	4%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = High - June 2008, Load Growth = High, Renewable Std = Base, Baseload Plant Avail = Late, Plant Cost = High, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 34	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,745	12,437	16,695	21,812	27,935	34,378	40,933	47,647	55,137	63,428	71,749	80,085	88,369	96,669	104,964	108,021	111,057	114,056	117,043
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	564	620	873	1,202	1,207	1,053	1,091	1,254	1,281	1,162	1,150	1,132	1,115	1,107	1,092	1,073	1,055	1,037
Oregon	1,382	2,537	3,267	4,324	5,839	7,877	8,576	9,310	10,096	11,330	12,995	13,834	14,624	15,356	16,048	16,690	16,436	16,111	15,705	15,217
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**16,268**	**21,640**	**28,523**	**37,013**	**44,161**	**51,296**	**58,834**	**67,721**	**77,704**	**86,745**	**95,859**	**104,857**	**113,832**	**122,761**	**125,550**	**128,241**	**130,815**	**133,297**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,693	4,258	5,116	6,123	6,444	6,555	6,714	7,490	8,291	8,321	8,336	8,285	8,300	8,295	8,315	8,336	8,357	8,379
Other (ID,WY)	828	1,033	1,305	1,631	2,088	2,657	2,842	2,914	3,006	3,442	3,899	3,929	3,939	3,909	3,918	3,873	3,907	3,940	3,973	4,005
California	88	176	185	194	204	213	223	233	243	256	287	336	339	341	345	348	352	354	357	360
Washington	266	303	382	481	636	811	888	907	932	1,074	1,216	1,213	1,213	1,203	1,203	1,202	1,196	1,191	1,185	1,180
Oregon	989	1,155	1,430	1,765	2,235	2,770	2,928	2,978	3,052	3,512	3,965	3,935	3,923	3,885	3,874	3,853	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**5,852**	**6,995**	**8,330**	**10,279**	**12,575**	**13,325**	**13,587**	**13,947**	**15,774**	**17,658**	**17,735**	**17,750**	**17,623**	**17,640**	**17,571**	**17,831**	**17,907**	**17,995**	**18,083**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	13%	15%	18%	21%	22%	22%	22%	25%	27%	27%	27%	26%	26%	26%	26%	26%	26%	25%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

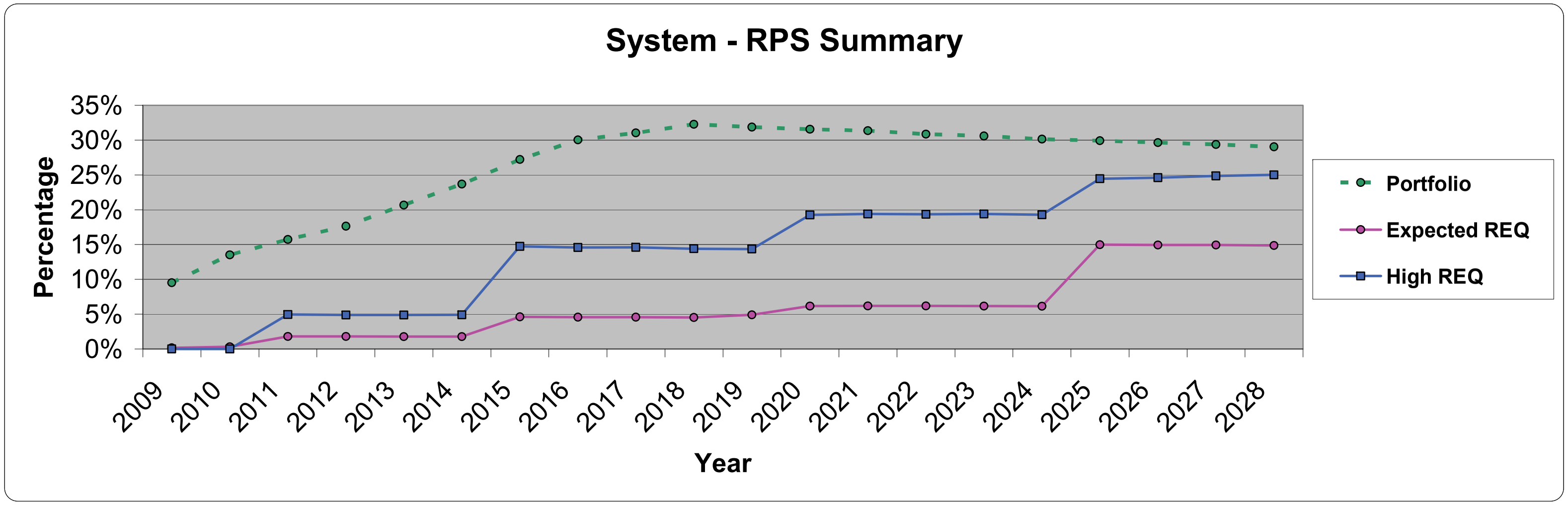


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 35

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,399	13,842	18,845	24,733	31,541	39,378	48,098	57,196	66,766	76,361	85,986	95,625	105,214	114,817	124,416	128,778	133,117	137,420	141,712
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	423	820	893	1,150	1,468	1,586	1,702	1,922	2,069	1,899	1,638	1,626	1,608	1,591	1,583	1,568	1,549	1,531	1,513
Oregon	1,382	2,939	4,125	5,633	7,612	10,056	11,579	13,588	15,772	18,229	20,659	22,259	23,806	25,294	26,742	28,141	28,637	29,054	29,382	29,621
Cumulative Surplus Credit Bank Balance	**6,942**	**12,761**	**18,788**	**25,371**	**33,495**	**43,065**	**52,544**	**63,388**	**74,890**	**87,064**	**98,918**	**109,882**	**121,058**	**132,116**	**143,150**	**154,140**	**158,983**	**163,719**	**168,333**	**172,846**
Adjusted Qualifying Renewables																				
Utah	2,960	3,839	4,443	5,003	5,888	6,808	7,838	8,720	9,097	9,570	9,595	9,625	9,640	9,588	9,604	9,599	9,619	9,640	9,661	9,683
Other (ID,WY)	828	1,392	1,722	2,047	2,522	3,047	3,641	4,161	4,384	4,641	4,652	4,688	4,700	4,670	4,682	4,635	4,676	4,718	4,758	4,798
California	88	176	185	194	204	228	272	307	321	339	339	336	339	341	345	348	352	354	357	360
Washington	266	423	519	617	777	936	1,143	1,302	1,368	1,454	1,454	1,452	1,451	1,441	1,441	1,440	1,434	1,429	1,423	1,418
Oregon	989	1,557	1,887	2,215	2,699	3,177	3,751	4,252	4,451	4,735	4,730	4,695	4,681	4,642	4,629	4,611	4,557	4,504	4,451	4,399
Adjusted Qualifying Renewables	**5,131**	**7,386**	**8,756**	**10,076**	**12,090**	**14,197**	**16,644**	**18,742**	**19,620**	**20,739**	**20,770**	**20,796**	**20,811**	**20,683**	**20,700**	**20,631**	**20,638**	**20,644**	**20,651**	**20,658**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	14%	16%	18%	21%	24%	27%	30%	31%	32%	32%	32%	31%	31%	31%	30%	30%	30%	29%	29%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

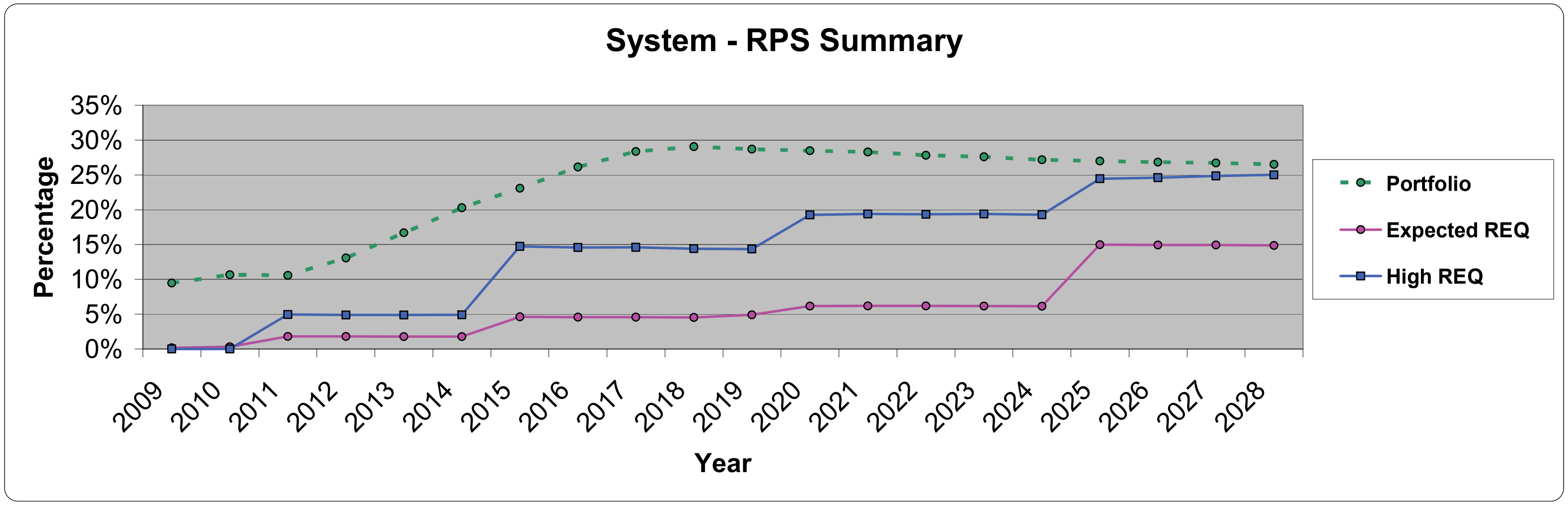


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 36

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,553	8,728	11,951	15,840	20,737	26,683	33,459	41,159	49,547	58,253	66,983	75,744	84,520	93,244	101,984	110,718	114,216	117,691	121,130	124,557
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	302	476	467	766	1,129	1,235	1,322	1,606	1,782	1,583	1,322	1,311	1,292	1,276	1,268	1,253	1,233	1,215	1,197
Oregon	1,378	2,527	2,971	3,805	5,188	7,120	8,016	9,424	11,192	13,141	15,064	16,160	17,206	18,192	19,139	20,037	20,036	19,961	19,802	19,559
Cumulative Surplus Credit Bank Balance	**6,931**	**11,557**	**15,398**	**20,112**	**26,690**	**34,932**	**42,711**	**51,906**	**62,345**	**73,176**	**83,631**	**93,227**	**103,036**	**112,729**	**122,398**	**132,023**	**135,504**	**138,885**	**142,147**	**145,314**
Adjusted Qualifying Renewables																				
Utah	2,953	3,175	3,223	3,889	4,897	5,946	6,777	7,699	8,388	8,706	8,731	8,761	8,775	8,724	8,740	8,734	8,755	8,776	8,797	8,818
Other (ID,WY)	824	1,028	1,044	1,425	1,965	2,556	3,033	3,574	3,974	4,143	4,153	4,185	4,196	4,166	4,176	4,130	4,167	4,203	4,238	4,273
California	88	176	185	194	204	213	229	266	292	305	305	336	339	341	345	348	352	354	357	360
Washington	265	302	296	414	596	779	949	1,116	1,238	1,296	1,296	1,294	1,293	1,283	1,283	1,282	1,276	1,271	1,266	1,260
Oregon	984	1,149	1,144	1,542	2,102	2,665	3,124	3,652	4,034	4,227	4,223	4,192	4,179	4,140	4,129	4,109	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,114**	**5,830**	**5,892**	**7,464**	**9,763**	**12,159**	**14,112**	**16,306**	**17,927**	**18,676**	**18,708**	**18,767**	**18,782**	**18,655**	**18,672**	**18,603**	**18,611**	**18,690**	**18,780**	**18,871**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	20%	23%	26%	28%	29%	29%	28%	28%	28%	28%	27%	27%	27%	27%	27%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

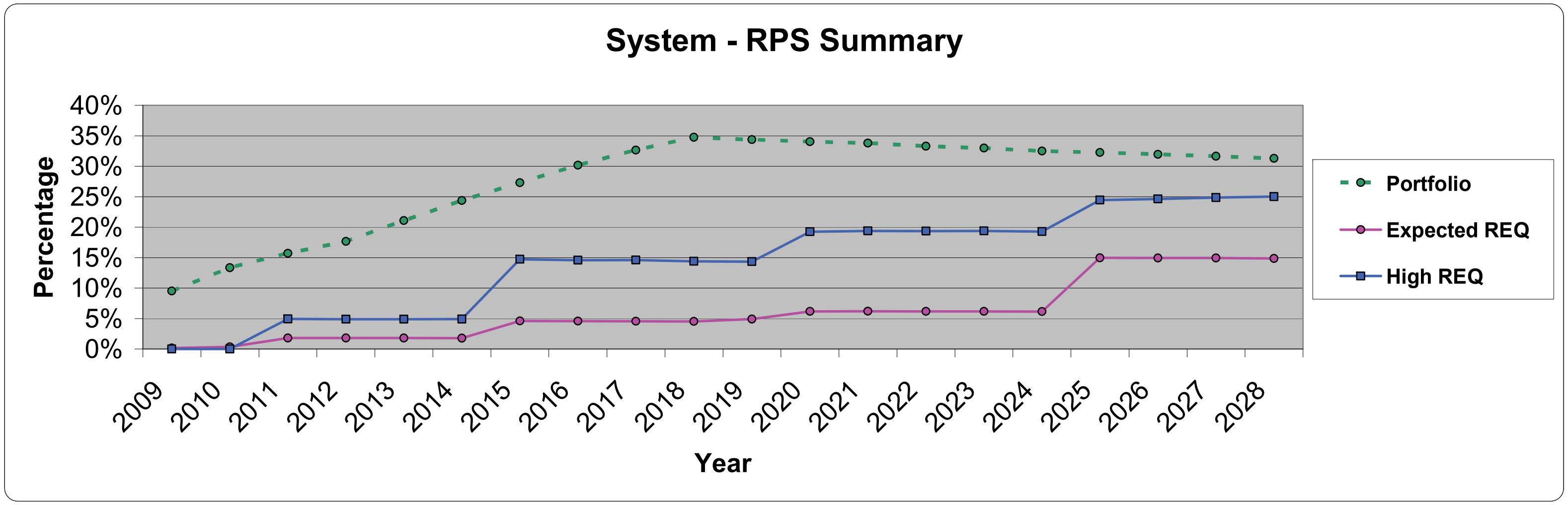


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 37

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,357	13,797	18,803	24,792	31,773	39,629	48,386	57,907	68,148	78,424	88,731	99,053	109,324	119,609	129,890	134,933	139,955	144,940	149,913
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	812	893	1,169	1,518	1,621	1,713	2,006	2,269	2,146	1,887	1,875	1,857	1,840	1,832	1,817	1,798	1,780	1,762
Oregon	1,382	2,913	4,097	5,607	7,646	10,194	11,728	13,758	16,191	19,042	21,873	23,870	25,814	27,698	29,540	31,335	32,223	33,028	33,741	34,360
Cumulative Surplus Credit Bank Balance	**6,942**	**12,685**	**18,705**	**25,304**	**33,608**	**43,485**	**52,979**	**63,857**	**76,104**	**89,459**	**102,443**	**114,488**	**126,742**	**138,878**	**150,989**	**163,057**	**168,974**	**174,781**	**180,460**	**186,036**
Adjusted Qualifying Renewables																				
Utah	2,960	3,797	4,440	5,007	5,989	6,981	7,857	8,756	9,521	10,241	10,277	10,307	10,322	10,270	10,286	10,281	10,301	10,322	10,343	10,365
Other (ID,WY)	828	1,369	1,720	2,049	2,579	3,146	3,652	4,182	4,629	5,027	5,046	5,085	5,098	5,069	5,081	5,033	5,079	5,124	5,169	5,213
California	88	176	185	194	204	235	272	308	338	366	367	363	363	362	362	362	357	354	357	360
Washington	266	415	518	618	795	968	1,146	1,309	1,445	1,576	1,579	1,576	1,575	1,566	1,565	1,564	1,559	1,553	1,548	1,542
Oregon	989	1,531	1,884	2,218	2,759	3,280	3,763	4,274	4,699	5,129	5,130	5,093	5,077	5,038	5,024	5,007	4,949	4,892	4,835	4,779
Adjusted Qualifying Renewables	**5,131**	**7,287**	**8,747**	**10,086**	**12,325**	**14,610**	**16,690**	**18,830**	**20,631**	**22,340**	**22,398**	**22,424**	**22,436**	**22,304**	**22,319**	**22,246**	**22,245**	**22,245**	**22,252**	**22,260**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	21%	24%	27%	30%	33%	35%	34%	34%	34%	33%	33%	32%	32%	32%	32%	31%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

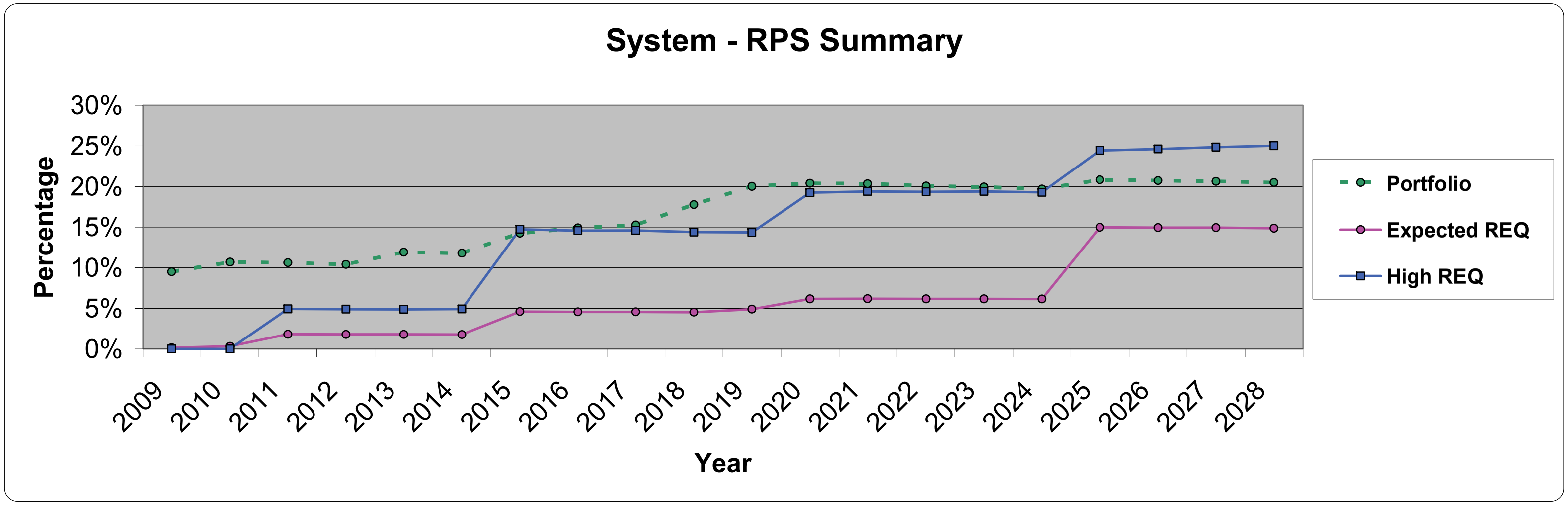


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = High - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Early, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 38

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,745	11,978	15,219	18,925	22,700	26,917	31,449	36,167	41,805	48,139	54,502	60,881	67,208	73,550	79,887	80,988	82,066	83,107	84,138
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	480	351	430	516	371	277	358	551	585	447	435	417	400	392	377	358	340	322
Oregon	1,382	2,537	2,987	3,430	4,096	4,739	4,122	3,667	3,282	3,427	3,943	3,641	3,294	2,889	2,448	1,954	574	-	-	-
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**15,444**	**19,000**	**23,451**	**27,954**	**31,410**	**35,392**	**39,806**	**45,784**	**52,667**	**58,591**	**64,610**	**70,513**	**76,398**	**82,233**	**81,939**	**82,423**	**83,447**	**84,460**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,233	3,242	3,705	3,775	4,217	4,532	4,718	5,639	6,333	6,364	6,378	6,327	6,342	6,337	6,358	6,379	6,400	6,421
Other (ID,WY)	828	1,033	1,050	1,063	1,295	1,319	1,565	1,750	1,853	2,375	2,769	2,790	2,797	2,766	2,772	2,731	2,752	2,773	2,794	2,814
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	378	382	482	537	568	736	858	856	855	846	845	844	839	833	828	822
Oregon	989	1,155	1,150	1,151	1,386	1,375	2,228	2,244	2,266	2,423	2,816	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**5,852**	**5,916**	**5,945**	**6,969**	**7,066**	**8,714**	**9,297**	**9,648**	**11,425**	**13,040**	**13,441**	**13,503**	**13,434**	**13,487**	**13,471**	**14,362**	**14,425**	**14,501**	**14,577**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	12%	12%	14%	15%	15%	18%	20%	20%	20%	20%	20%	20%	21%	21%	21%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

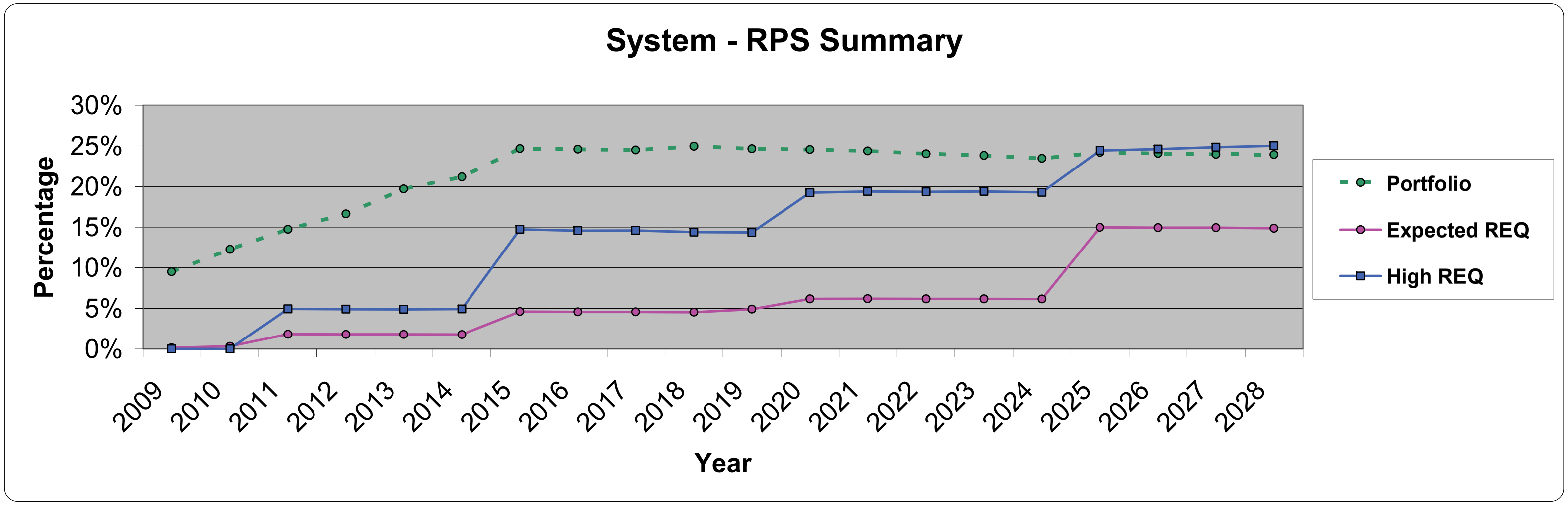


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = High, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 39

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,108	13,316	18,076	23,725	29,902	37,090	44,389	51,755	59,358	66,985	74,642	82,314	89,954	97,610	105,260	107,674	110,065	112,420	114,823
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	370	724	806	1,062	1,309	1,352	1,324	1,346	1,394	1,180	919	908	893	880	872	857	837	819	812
Oregon	1,382	2,760	3,803	5,164	6,999	9,069	10,209	11,381	12,549	13,849	15,124	15,577	15,981	16,339	16,658	16,926	16,302	15,610	14,840	14,026
Cumulative Surplus Credit Bank Balance	**6,941**	**12,238**	**17,844**	**24,045**	**31,786**	**40,281**	**48,651**	**57,095**	**65,651**	**74,601**	**83,289**	**91,139**	**99,203**	**107,186**	**115,147**	**123,058**	**124,832**	**126,512**	**128,079**	**129,661**
Adjusted Qualifying Renewables																				
Utah	2,959	3,548	4,208	4,759	5,649	6,177	7,188	7,299	7,366	7,603	7,627	7,657	7,672	7,640	7,655	7,650	7,671	7,692	7,713	7,794
Other (ID,WY)	828	1,232	1,591	1,911	2,388	2,688	3,269	3,343	3,383	3,507	3,516	3,543	3,552	3,533	3,541	3,497	3,527	3,556	3,585	3,649
California	88	176	185	194	204	213	246	250	251	260	263	336	339	341	345	348	352	354	357	360
Washington	266	370	476	573	733	821	1,024	1,043	1,051	1,095	1,095	1,092	1,092	1,086	1,085	1,084	1,078	1,073	1,068	1,073
Oregon	988	1,379	1,743	2,068	2,555	2,803	3,368	3,416	3,435	3,578	3,575	3,549	3,538	3,511	3,501	3,479	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**6,705**	**8,204**	**9,505**	**11,530**	**12,702**	**15,095**	**15,350**	**15,487**	**16,042**	**16,076**	**16,177**	**16,192**	**16,111**	**16,128**	**16,059**	**16,689**	**16,761**	**16,845**	**17,036**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	12%	15%	17%	20%	21%	25%	25%	24%	25%	25%	25%	24%	24%	24%	23%	24%	24%	24%	24%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



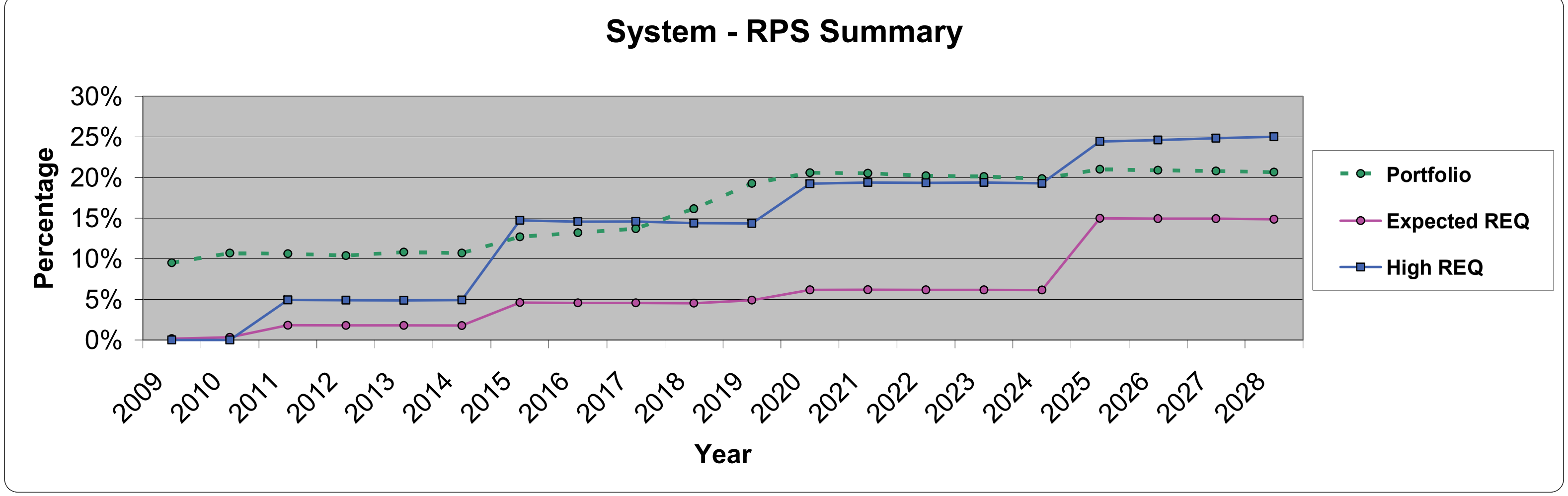
System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = High - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = High, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 40

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,743	11,975	15,216	18,646	22,145	25,822	29,757	33,915	39,042	45,175	51,612	58,062	64,462	70,877	77,287	78,459	79,610	80,724	81,827
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	350	380	415	222	69	146	356	455	424	462	443	427	419	404	384	366	348
Oregon	1,382	2,536	2,985	3,428	3,928	4,407	3,472	2,664	1,951	1,796	2,194	1,935	1,629	1,267	867	415	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,941**	**11,583**	**15,439**	**18,994**	**22,954**	**26,967**	**29,517**	**32,490**	**36,013**	**41,194**	**47,825**	**53,970**	**60,153**	**66,172**	**72,171**	**78,121**	**78,863**	**79,994**	**81,090**	**82,175**
Adjusted Qualifying Renewables																				
Utah	2,959	3,184	3,231	3,241	3,430	3,499	3,677	3,934	4,158	5,127	6,133	6,436	6,451	6,400	6,415	6,410	6,430	6,451	6,472	6,494
Other (ID,WY)	828	1,032	1,049	1,063	1,141	1,162	1,255	1,405	1,530	2,080	2,654	2,832	2,839	2,808	2,815	2,773	2,795	2,817	2,838	2,858
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	328	332	383	428	466	643	822	869	869	859	858	857	852	846	841	836
Oregon	988	1,155	1,149	1,150	1,220	1,211	2,228	2,244	2,266	2,277	2,698	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,129**	**5,850**	**5,912**	**5,945**	**6,322**	**6,418**	**7,767**	**8,245**	**8,663**	**10,380**	**12,570**	**13,569**	**13,631**	**13,562**	**13,615**	**13,599**	**14,490**	**14,554**	**14,630**	**14,707**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	11%	11%	13%	13%	14%	16%	19%	21%	21%	20%	20%	20%	21%	21%	21%	21%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

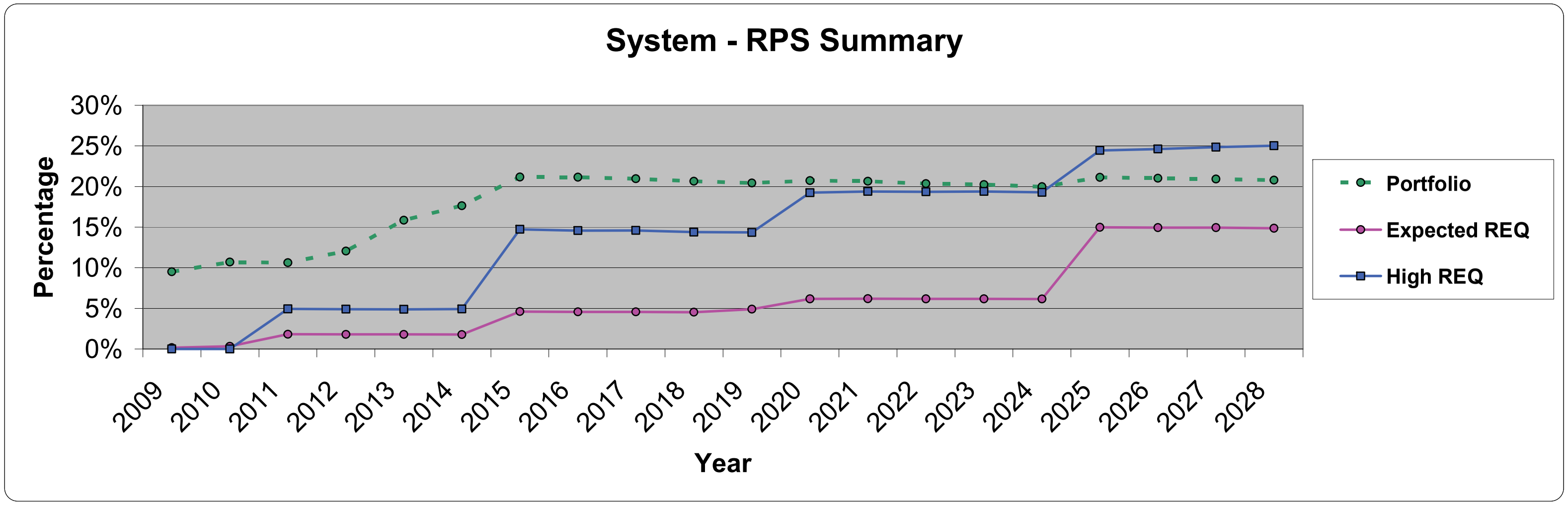


Study Description

CO2 Type = Hard Cap 3/, CO2 Cost = N/A, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 41

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,742	11,973	15,614	20,302	25,571	31,852	38,243	44,659	51,086	57,537	64,019	70,516	76,961	83,421	89,877	91,095	92,291	93,451	94,600
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	423	682	968	1,021	993	1,007	1,005	751	490	478	460	443	435	420	401	383	365
Oregon	1,382	2,536	2,984	3,669	4,926	6,456	7,059	7,697	8,308	8,917	9,502	9,270	8,991	8,655	8,282	7,856	6,545	5,173	3,730	2,216
Cumulative Surplus Credit Bank Balance	**6,942**	**11,580**	**15,436**	**19,706**	**25,910**	**32,996**	**39,932**	**46,933**	**53,974**	**61,008**	**67,790**	**73,779**	**79,985**	**86,075**	**92,147**	**98,168**	**98,061**	**97,865**	**97,565**	**97,181**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,641	4,688	5,269	6,280	6,391	6,415	6,427	6,452	6,482	6,496	6,445	6,461	6,455	6,476	6,497	6,518	6,539
Other (ID,WY)	828	1,031	1,049	1,286	1,848	2,171	2,748	2,820	2,834	2,829	2,838	2,859	2,866	2,835	2,842	2,800	2,822	2,844	2,865	2,886
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	369	558	655	859	877	878	880	880	878	877	867	867	866	860	855	849	844
Oregon	989	1,154	1,149	1,392	1,977	2,263	2,831	2,882	2,877	2,886	2,885	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**6,882**	**9,274**	**10,572**	**12,942**	**13,203**	**13,248**	**13,275**	**13,317**	**13,650**	**13,712**	**13,642**	**13,696**	**13,680**	**14,571**	**14,636**	**14,712**	**14,789**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	16%	18%	21%	21%	21%	21%	20%	21%	21%	20%	20%	20%	21%	21%	21%	21%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

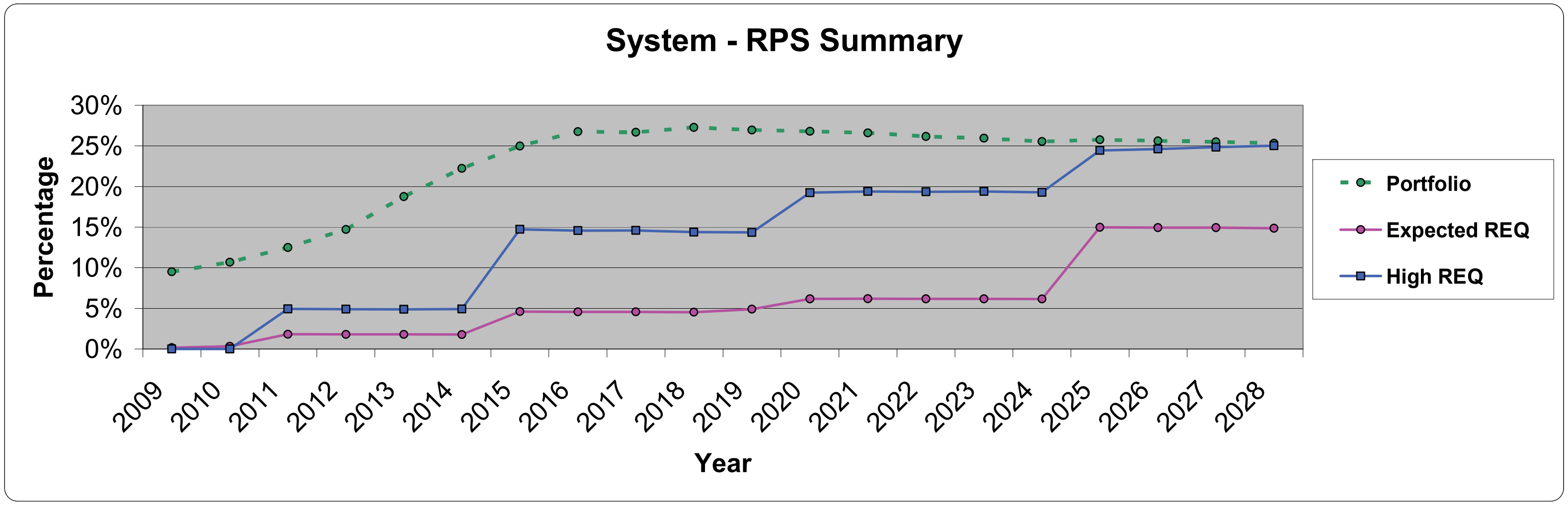


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 15%, Class 3 DSM = Excluded

System - RPS Report - Case # 42

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,741	12,419	16,712	22,126	28,565	35,829	43,696	51,642	59,872	68,126	76,411	84,710	92,958	101,222	109,480	112,501	115,501	118,463	121,415
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	560	624	934	1,314	1,414	1,442	1,556	1,614	1,409	1,149	1,137	1,118	1,102	1,094	1,079	1,059	1,041	1,024
Oregon	1,382	2,535	3,256	4,334	6,028	8,253	9,438	10,944	12,453	14,122	15,765	16,583	17,352	18,062	18,734	19,355	19,080	18,734	18,307	17,799
Cumulative Surplus Credit Bank Balance	**6,942**	**11,579**	**16,235**	**21,671**	**29,087**	**38,132**	**46,681**	**56,083**	**65,650**	**75,607**	**85,300**	**94,143**	**103,199**	**112,139**	**121,057**	**129,929**	**132,660**	**135,294**	**137,812**	**140,237**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,678	4,293	5,413	6,439	7,265	7,867	7,945	8,230	8,254	8,285	8,299	8,248	8,263	8,258	8,279	8,300	8,321	8,342
Other (ID,WY)	828	1,031	1,297	1,650	2,255	2,837	3,313	3,670	3,718	3,868	3,878	3,908	3,918	3,888	3,897	3,852	3,886	3,919	3,951	3,983
California	88	176	185	194	204	213	249	272	275	286	286	336	339	341	345	348	352	354	357	360
Washington	266	303	379	488	690	869	1,038	1,146	1,157	1,209	1,209	1,207	1,206	1,197	1,196	1,195	1,190	1,184	1,179	1,173
Oregon	989	1,153	1,421	1,786	2,413	2,958	3,413	3,750	3,775	3,947	3,943	3,914	3,902	3,864	3,853	3,832	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,844**	**6,960**	**8,412**	**10,976**	**13,316**	**15,277**	**16,706**	**16,870**	**17,540**	**17,571**	**17,649**	**17,665**	**17,538**	**17,555**	**17,486**	**17,767**	**17,843**	**17,930**	**18,018**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	13%	15%	19%	22%	25%	27%	27%	27%	27%	27%	27%	26%	26%	26%	26%	26%	26%	25%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

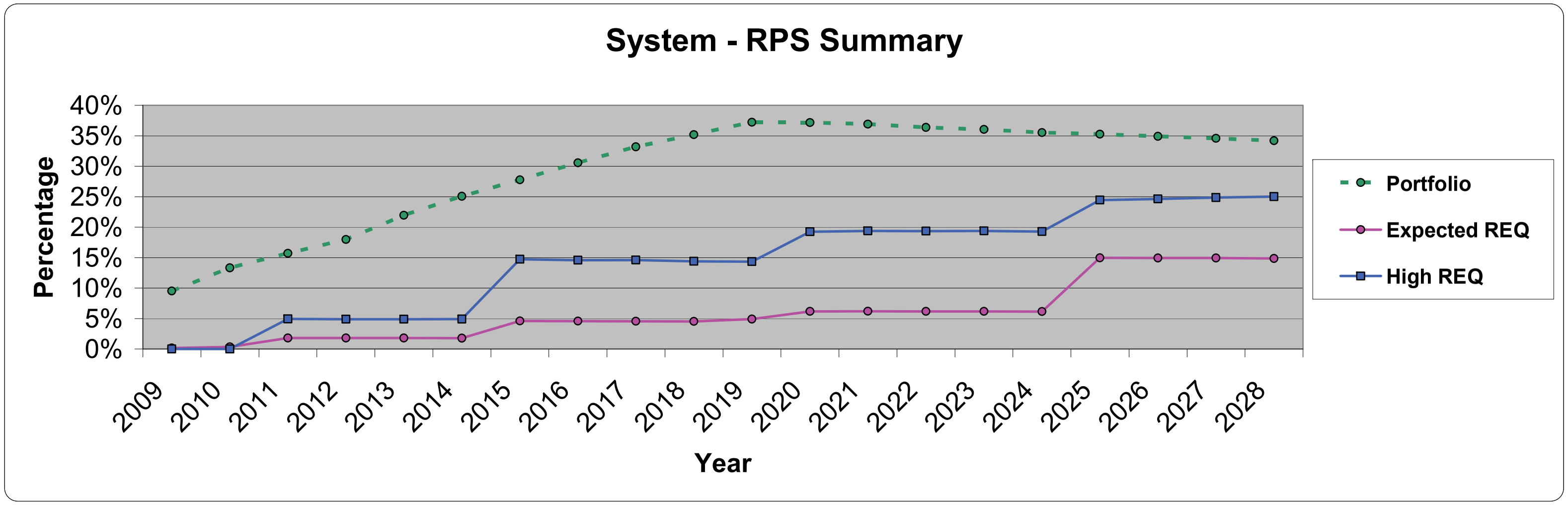


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 15%, Class 3 DSM = Excluded

System - RPS Report - Case # 43

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	9,355	13,793	18,875	25,080	32,232	40,207	49,070	58,733	69,091	80,147	91,322	102,511	113,650	124,804	135,952	141,864	147,753	153,606	159,448
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	415	811	907	1,223	1,589	1,674	1,754	2,052	2,316	2,309	2,188	2,192	2,174	2,157	2,149	2,134	2,115	2,097	2,079
Oregon	1,382	2,912	4,095	5,650	7,820	10,469	12,073	14,166	16,682	19,603	22,890	25,393	27,841	30,229	32,574	34,873	36,260	37,559	38,761	39,865
Cumulative Surplus Credit Bank Balance	**6,942**	**12,681**	**18,699**	**25,432**	**34,122**	**44,290**	**53,954**	**64,989**	**77,467**	**91,010**	**105,347**	**118,903**	**132,545**	**146,053**	**159,535**	**172,975**	**180,258**	**187,427**	**194,464**	**201,391**
Adjusted Qualifying Renewables																				
Utah	2,959	3,795	4,438	5,082	6,205	7,152	7,974	8,863	9,663	10,358	11,055	11,175	11,190	11,138	11,154	11,149	11,169	11,190	11,211	11,233
Other (ID,WY)	828	1,368	1,719	2,091	2,700	3,244	3,720	4,244	4,711	5,095	5,496	5,590	5,605	5,576	5,589	5,539	5,591	5,642	5,692	5,741
California	88	176	185	194	209	242	277	312	343	371	398	398	398	397	397	397	392	387	382	377
Washington	266	415	518	632	835	999	1,168	1,328	1,471	1,598	1,721	1,735	1,734	1,724	1,724	1,723	1,717	1,712	1,706	1,701
Oregon	989	1,530	1,883	2,264	2,889	3,382	3,832	4,337	4,783	5,198	5,588	5,599	5,582	5,541	5,527	5,511	5,448	5,386	5,324	5,264
Adjusted Qualifying Renewables	**5,130**	**7,283**	**8,743**	**10,263**	**12,839**	**15,019**	**16,971**	**19,084**	**20,971**	**22,620**	**24,257**	**24,496**	**24,508**	**24,376**	**24,391**	**24,318**	**24,317**	**24,316**	**24,315**	**24,315**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	13%	16%	18%	22%	25%	28%	31%	33%	35%	37%	37%	37%	36%	36%	36%	35%	35%	35%	34%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

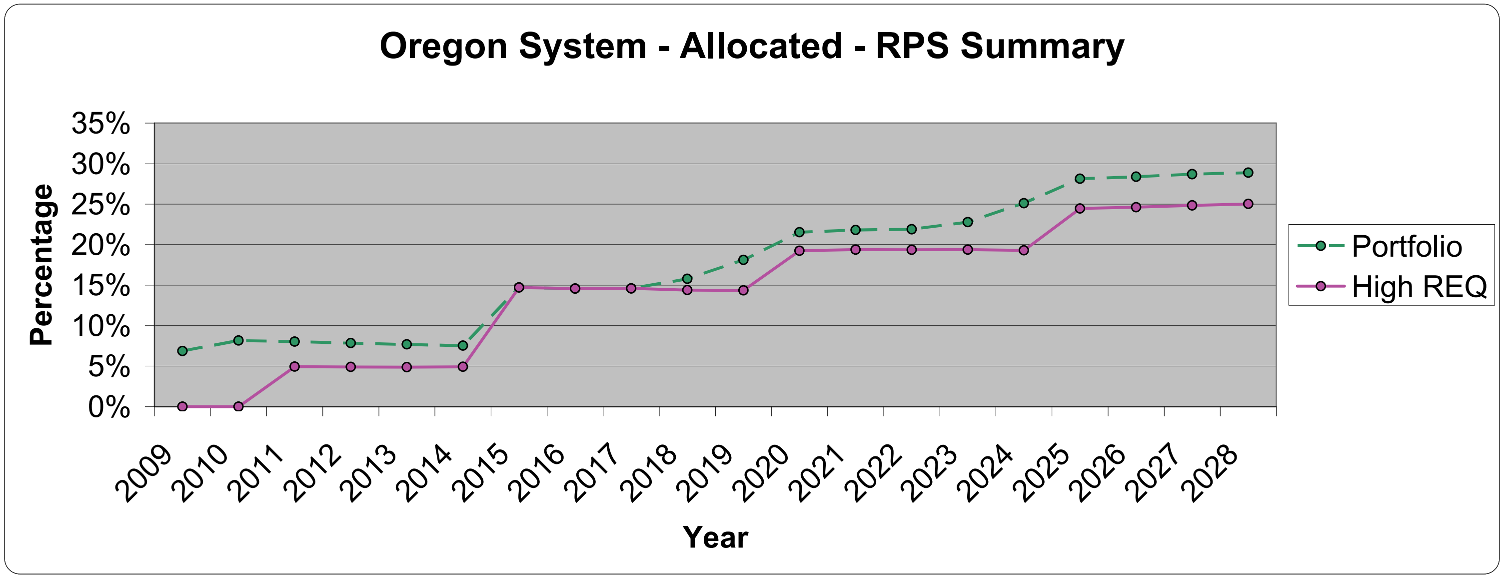


Study Description

CO2 Type = CO2 tax, CO2 Cost = $100, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 15%, Class 3 DSM = Excluded

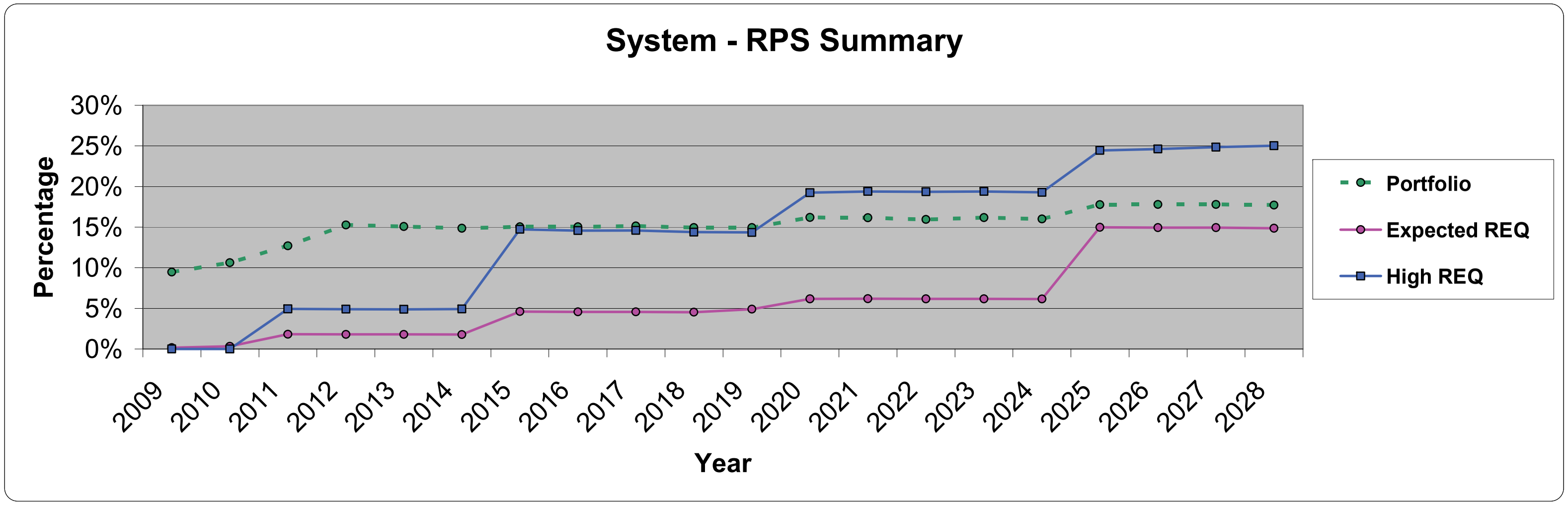
Oregon System - Allocated RPS Report - Case # 44

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Oregon - System																				
Energy GWh																				
RPS Requirement (System)	-	-	2,750	2,794	2,858	2,942	9,003	9,102	9,223	9,245	9,353	12,680	12,871	12,969	13,121	13,200	16,863	17,140	17,467	17,802
Eligible Resources	3,581	4,090	4,090	4,091	4,090	4,088	3,818	3,843	3,836	3,818	3,832	3,829	3,827	3,687	3,686	3,577	3,571	3,564	3,558	3,552
Incremental IRP Resources	127	365	372	391	403	423	818	2,000	4,097	6,327	7,977	10,362	10,658	10,988	11,729	13,624	15,838	16,196	16,615	16,988
Surplus/(Deficit)	3,708	4,456	1,712	1,688	1,636	1,568	(4,367)	(3,260)	(1,290)	900	2,457	1,510	1,613	1,707	2,294	4,001	2,545	2,620	2,707	2,739
Banking:																				
Surplus Credit Prior Year	1,484	5,191	9,647	11,359	13,047	14,683	16,251	11,883	8,624	7,333	8,233	10,690	12,200	13,813	15,520	17,814	21,815	24,360	26,980	29,687
Current Year Surplus Credits	3,708	4,456	1,712	1,688	1,636	1,568	-	-	-	900	2,457	1,510	1,613	1,707	2,294	4,001	2,545	2,620	2,707	2,739
Surplus Credits Used in Current Year	-	-	-	-	-	-	(4,367)	(3,260)	(1,290)	-	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	5,191	9,647	11,359	13,047	14,683	16,251	11,883	8,624	7,333	8,233	10,690	12,200	13,813	15,520	17,814	21,815	24,360	26,980	29,687	32,426
Adjusted Qualifying Renewables	3,708	4,456	4,462	4,481	4,493	4,511	9,003	9,102	9,223	10,145	11,809	14,191	14,484	14,675	15,415	17,201	19,408	19,760	20,174	20,540
Allocation Factor	26.5%	25.7%	25.5%	25.3%	25.2%	24.9%	24.8%	24.7%	24.6%	24.6%	24.6%	24.4%	24.3%	24.3%	24.3%	24.3%	24.1%	23.8%	23.6%	23.4%
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	7%	8%	8%	8%	8%	8%	15%	15%	15%	16%	18%	22%	22%	22%	23%	25%	28%	28%	29%	29%
Portfolio Meets RPS																				
High REQ	0%	0%	5%	5%	5%	5%	15%	15%	15%	14%	14%	19%	19%	19%	19%	19%	24%	25%	25%	25%



System - RPS Report - Case # 45

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,718	12,446	16,874	21,369	25,929	30,421	35,002	39,674	44,357	49,072	53,748	58,431	63,055	67,850	72,643	71,855	71,166	70,376	69,536
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	567	658	791	803	565	336	358	369	115	-	-	-	-	-	-	-	-	-
Oregon	1,376	2,521	3,272	4,432	5,573	6,682	6,228	5,801	5,389	4,972	4,538	3,296	2,010	670	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,539**	**16,284**	**21,964**	**27,732**	**33,414**	**37,214**	**41,138**	**45,421**	**49,697**	**53,725**	**57,044**	**60,441**	**63,725**	**67,850**	**72,643**	**71,855**	**71,166**	**70,376**	**69,536**
Adjusted Qualifying Renewables																				
Utah	2,950	3,168	3,728	4,428	4,495	4,560	4,492	4,581	4,672	4,683	4,715	4,750	4,763	4,717	4,866	4,868	5,257	5,301	5,358	5,391
Other (ID,WY)	823	1,024	1,325	1,726	1,739	1,767	1,722	1,778	1,827	1,824	1,835	1,851	1,855	1,825	1,908	1,873	1,938	1,994	2,006	2,026
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	388	512	522	526	532	546	559	561	632	636	640	644	647	651	655	659	662	666
Oregon	983	1,145	1,451	1,868	1,861	1,842	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,812**	**7,077**	**8,729**	**8,820**	**8,908**	**9,197**	**9,381**	**9,568**	**9,598**	**9,745**	**10,669**	**10,730**	**10,681**	**10,948**	**10,950**	**12,264**	**12,394**	**12,506**	**12,602**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	13%	15%	15%	15%	15%	15%	15%	15%	15%	16%	16%	16%	16%	16%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

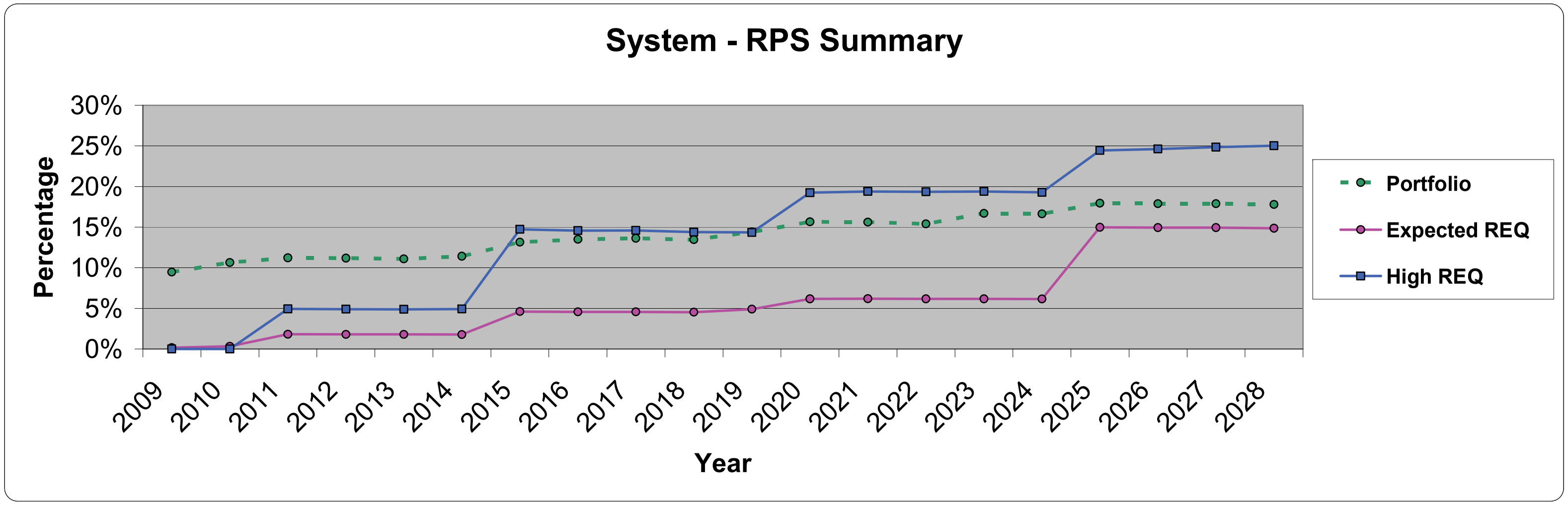


Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base/PTC expires, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 46

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,721	12,096	15,528	19,027	22,704	26,534	30,572	34,702	38,844	43,311	47,717	52,131	56,485	61,544	66,663	66,319	65,899	65,379	64,782
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	503	411	427	460	283	116	160	171	-	-	-	-	-	-	-	-	-	-
Oregon	1,377	2,523	3,059	3,617	4,159	4,743	3,898	3,152	2,422	1,687	1,122	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,928**	**11,545**	**15,658**	**19,556**	**23,613**	**27,907**	**30,715**	**33,839**	**37,284**	**40,702**	**44,433**	**47,717**	**52,131**	**56,485**	**61,544**	**66,663**	**66,319**	**65,899**	**65,379**	**64,782**
Adjusted Qualifying Renewables																				
Utah	2,951	3,170	3,375	3,432	3,499	3,677	3,830	4,038	4,130	4,142	4,492	4,522	4,535	4,488	5,090	5,143	5,257	5,301	5,358	5,391
Other (ID,WY)	823	1,025	1,129	1,169	1,179	1,263	1,343	1,465	1,514	1,512	1,706	1,718	1,722	1,692	2,039	2,034	2,048	2,061	2,075	2,087
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	324	330	340	364	411	447	461	463	632	636	640	644	647	651	655	659	662	666
Oregon	983	1,146	1,237	1,265	1,262	1,317	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,817**	**6,249**	**6,391**	**6,484**	**6,835**	**8,036**	**8,427**	**8,614**	**8,646**	**9,393**	**10,308**	**10,369**	**10,319**	**11,302**	**11,386**	**12,373**	**12,461**	**12,574**	**12,664**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	11%	11%	11%	13%	14%	14%	13%	14%	16%	16%	15%	17%	17%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

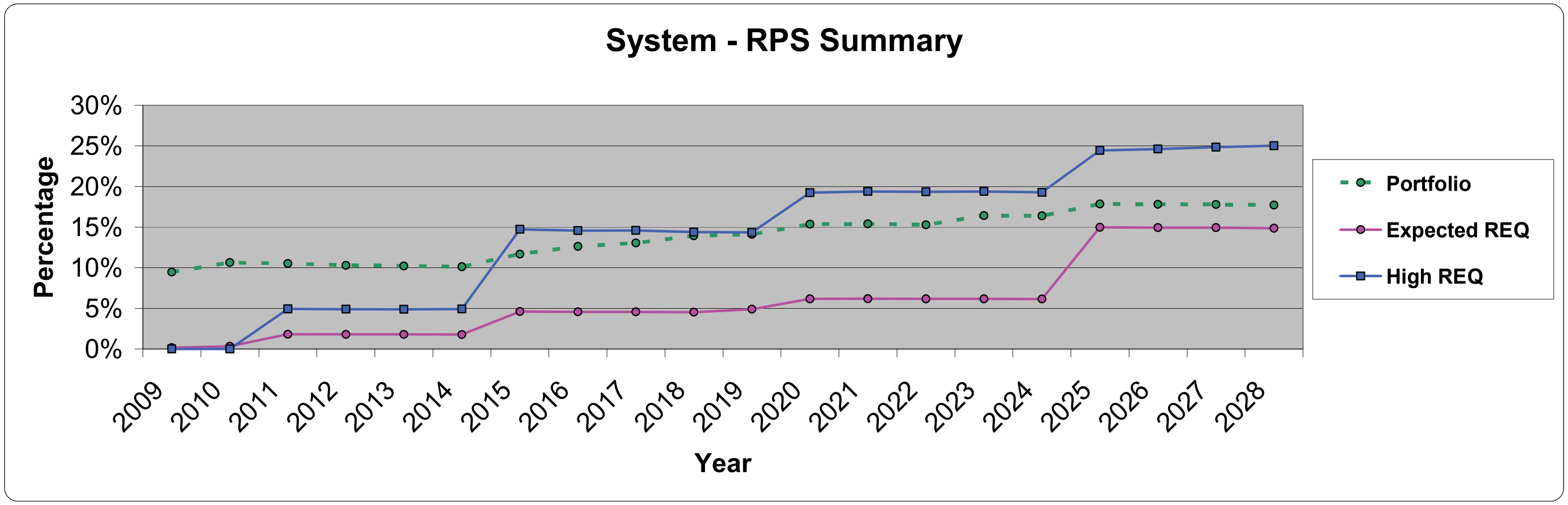


Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = Fixed RPS-compliant wind schedule, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 47

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,721	11,932	15,148	18,431	21,782	25,069	28,797	32,719	37,037	41,320	45,589	49,893	54,139	59,062	64,057	63,463	62,794	62,024	61,178
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	473	342	348	361	124	18	66	165	-	-	-	-	-	-	-	-	-	-
Oregon	1,377	2,523	2,959	3,387	3,799	4,189	3,023	2,094	1,243	611	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,928**	**11,545**	**15,364**	**18,877**	**22,578**	**26,332**	**28,216**	**30,910**	**34,027**	**37,813**	**41,320**	**45,589**	**49,893**	**54,139**	**59,062**	**64,057**	**63,463**	**62,794**	**62,024**	**61,178**
Adjusted Qualifying Renewables																				
Utah	2,951	3,170	3,210	3,216	3,283	3,351	3,287	3,729	3,922	4,318	4,344	4,406	4,449	4,439	4,975	5,039	5,257	5,301	5,358	5,391
Other (ID,WY)	823	1,025	1,038	1,049	1,058	1,077	1,031	1,287	1,393	1,613	1,621	1,651	1,671	1,663	1,972	1,973	1,986	1,999	2,012	2,024
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	294	291	301	305	370	391	422	495	632	636	640	644	647	651	655	659	662	666
Oregon	983	1,146	1,137	1,135	1,132	1,123	2,228	2,244	2,266	2,277	2,341	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,817**	**5,864**	**5,886**	**5,978**	**6,068**	**7,140**	**7,883**	**8,247**	**8,956**	**9,200**	**10,124**	**10,232**	**10,241**	**11,120**	**11,221**	**12,312**	**12,399**	**12,511**	**12,601**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	10%	10%	12%	13%	13%	14%	14%	15%	15%	15%	16%	16%	18%	18%	18%	18%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

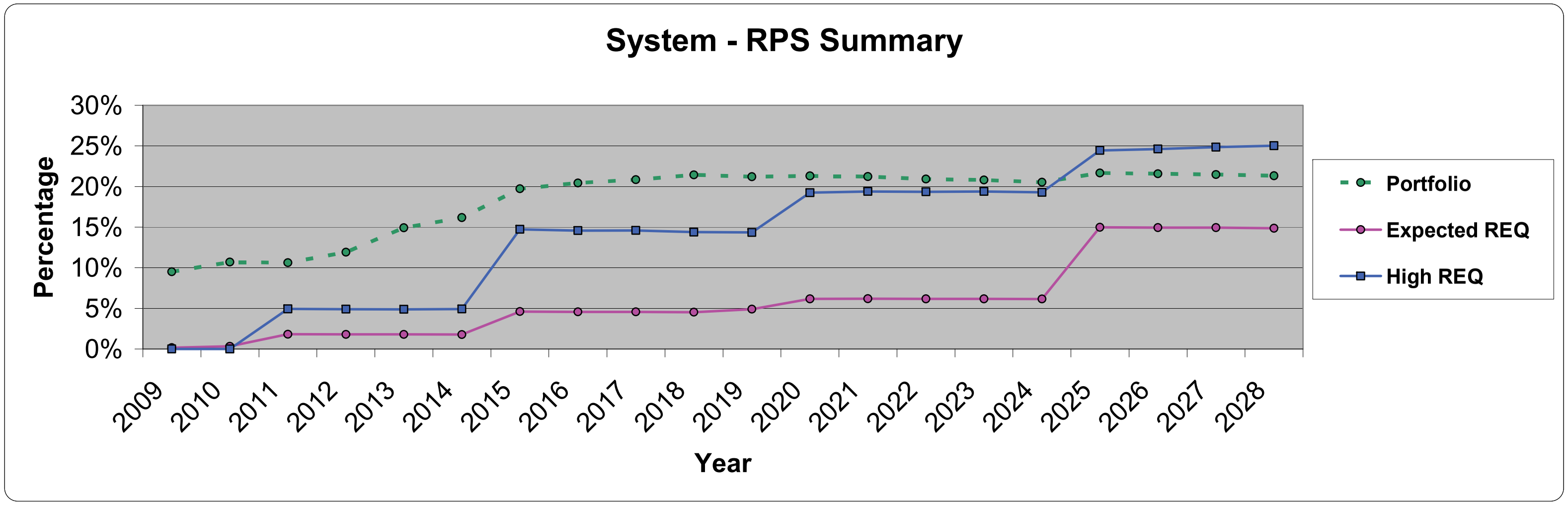


Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = Optimized RPS-compliant renewables, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Excluded

System - RPS Report - Case # 48

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,745	11,977	15,585	20,039	24,932	30,837	37,036	43,422	50,064	56,731	63,428	70,139	76,800	83,476	90,146	91,580	92,991	94,366	95,730
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	480	418	634	856	883	889	967	1,039	829	569	557	539	522	514	499	479	462	444
Oregon	1,382	2,537	2,987	3,651	4,767	6,075	6,455	6,981	7,574	8,309	9,021	8,914	8,760	8,549	8,300	8,000	6,812	5,563	4,241	2,847
Cumulative Surplus Credit Bank Balance	**6,942**	**11,585**	**15,443**	**19,654**	**25,440**	**31,863**	**38,175**	**44,906**	**51,962**	**59,413**	**66,581**	**72,910**	**79,456**	**85,887**	**92,298**	**98,660**	**98,891**	**99,033**	**99,069**	**99,021**
Adjusted Qualifying Renewables																				
Utah	2,960	3,185	3,232	3,609	4,454	4,893	5,904	6,200	6,385	6,642	6,667	6,697	6,712	6,661	6,676	6,671	6,691	6,712	6,733	6,755
Other (ID,WY)	828	1,033	1,050	1,268	1,716	1,956	2,533	2,710	2,817	2,953	2,962	2,984	2,992	2,960	2,968	2,925	2,949	2,972	2,995	3,017
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	363	515	586	790	842	872	919	919	917	916	907	906	905	900	894	889	883
Oregon	989	1,155	1,150	1,372	1,836	2,040	2,609	2,769	2,860	3,013	3,011	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,131**	**5,852**	**5,915**	**6,806**	**8,724**	**9,689**	**12,059**	**12,754**	**13,177**	**13,780**	**13,822**	**14,030**	**14,092**	**14,022**	**14,076**	**14,060**	**14,953**	**15,018**	**15,096**	**15,174**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	15%	16%	20%	20%	21%	21%	21%	21%	21%	21%	21%	21%	22%	22%	21%	21%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



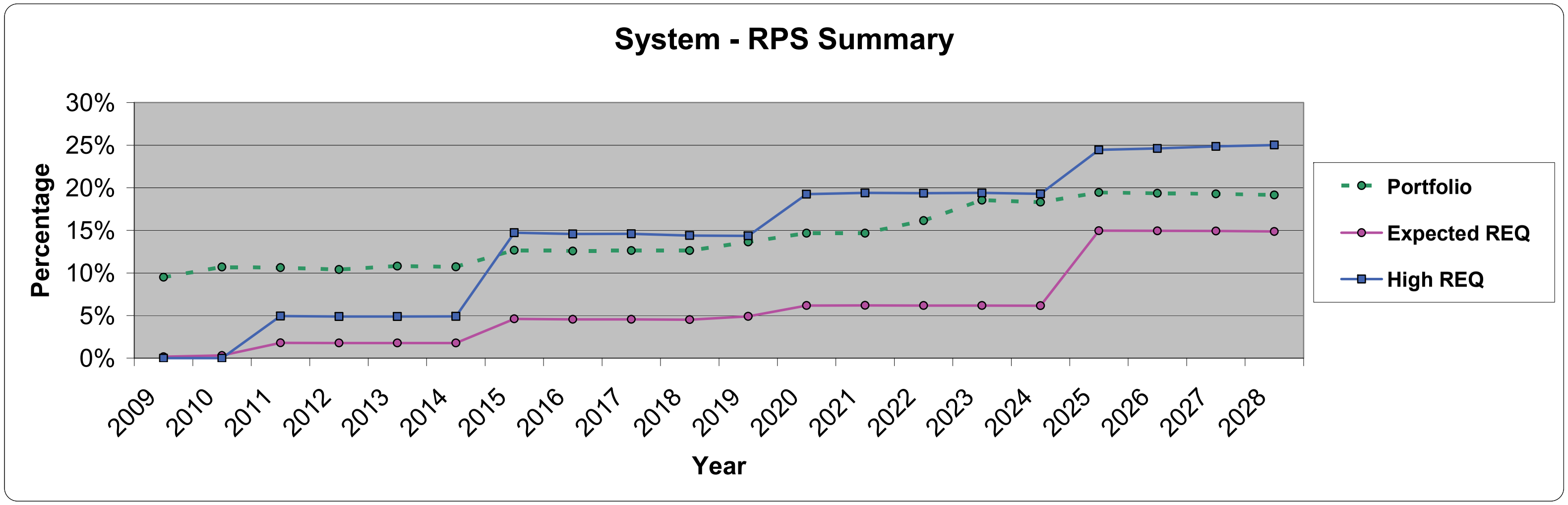
Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = Base, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 12%, Class 3 DSM = Included

B-Series Portfolio RPS Summary

System - RPS Report - Case # 2B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,743	11,975	15,216	18,646	22,145	25,809	29,515	33,284	37,125	40,937	44,506	48,067	52,798	58,613	64,419	64,987	65,531	66,044	66,542
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	350	380	415	220	25	34	50	-	-	-	-	102	199	183	163	146	128
Oregon	1,382	2,536	2,985	3,428	3,928	4,407	3,464	2,522	1,581	669	-	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,941**	**11,583**	**15,439**	**18,994**	**22,954**	**26,967**	**29,494**	**32,062**	**34,898**	**37,843**	**40,937**	**44,506**	**48,067**	**52,798**	**58,715**	**64,618**	**65,170**	**65,694**	**66,190**	**66,670**
Adjusted Qualifying Renewables																				
Utah	2,959	3,184	3,231	3,241	3,430	3,499	3,664	3,706	3,769	3,841	4,094	4,112	4,138	4,807	5,814	5,807	5,825	5,845	5,871	5,889
Other (ID,WY)	828	1,032	1,049	1,063	1,140	1,162	1,248	1,274	1,305	1,338	1,476	1,480	1,490	1,878	2,463	2,421	2,438	2,455	2,476	2,490
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	296	328	332	381	386	395	408	632	636	640	644	749	747	741	736	731	725
Oregon	988	1,155	1,149	1,150	1,220	1,211	2,228	2,244	2,266	2,277	2,430	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,129**	**5,850**	**5,912**	**5,945**	**6,322**	**6,417**	**7,744**	**7,843**	**7,978**	**8,117**	**8,895**	**9,660**	**9,740**	**10,823**	**12,553**	**12,534**	**13,417**	**13,476**	**13,558**	**13,625**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	10%	11%	11%	13%	13%	13%	13%	14%	15%	15%	16%	19%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

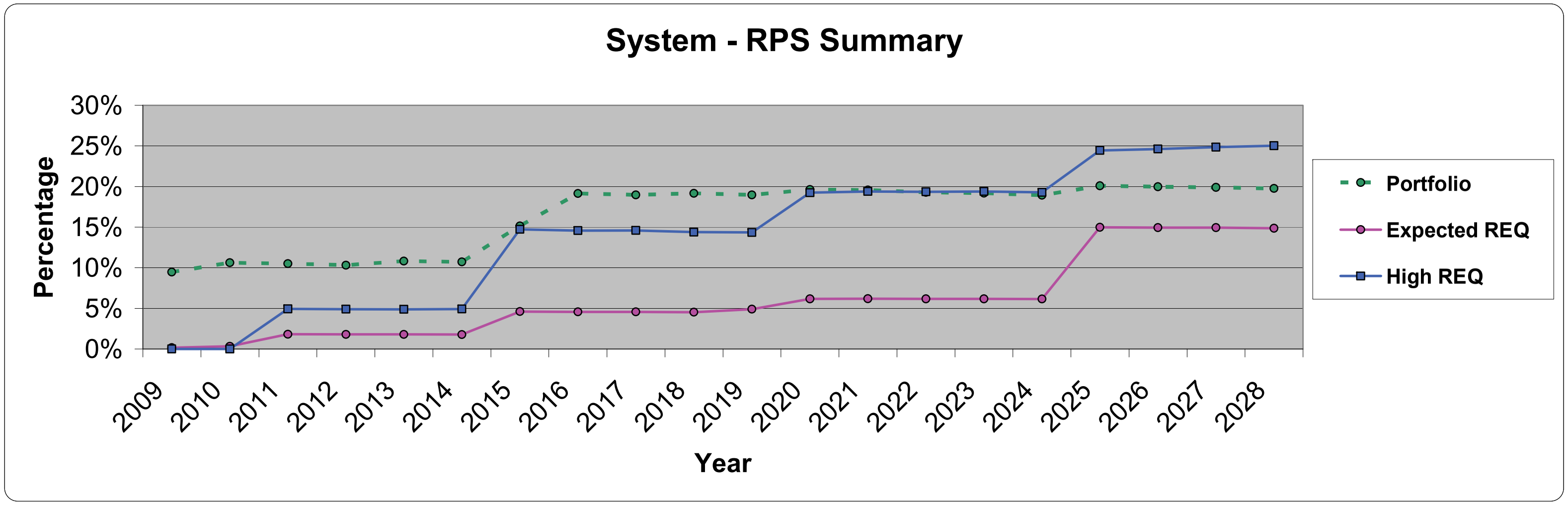

System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $0, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 5B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,076	26,608	32,463	38,342	44,362	50,407	56,483	62,574	68,614	74,668	80,718	81,531	82,321	83,075	83,818
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	379	576	811	833	602	342	330	312	295	287	272	253	235	217
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,935	4,257	4,553	4,923	5,269	4,800	4,286	3,714	3,107	2,445	901	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,861**	**22,832**	**26,856**	**30,922**	**37,295**	**43,706**	**50,118**	**56,279**	**61,626**	**67,190**	**72,639**	**78,070**	**83,451**	**82,704**	**82,574**	**83,310**	**84,035**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	4,533	5,855	5,879	6,021	6,045	6,076	6,091	6,040	6,055	6,050	6,070	6,091	6,112	6,134
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,746	2,511	2,524	2,595	2,603	2,623	2,629	2,598	2,604	2,563	2,583	2,602	2,621	2,639
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	539	779	780	806	806	803	803	793	793	792	786	781	775	770
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,566	2,563	2,647	2,646	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,892**	**6,330**	**6,427**	**9,269**	**11,944**	**11,988**	**12,321**	**12,363**	**12,934**	**12,995**	**12,926**	**12,978**	**12,963**	**13,852**	**13,914**	**13,988**	**14,062**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	15%	19%	19%	19%	19%	20%	20%	19%	19%	19%	20%	20%	20%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

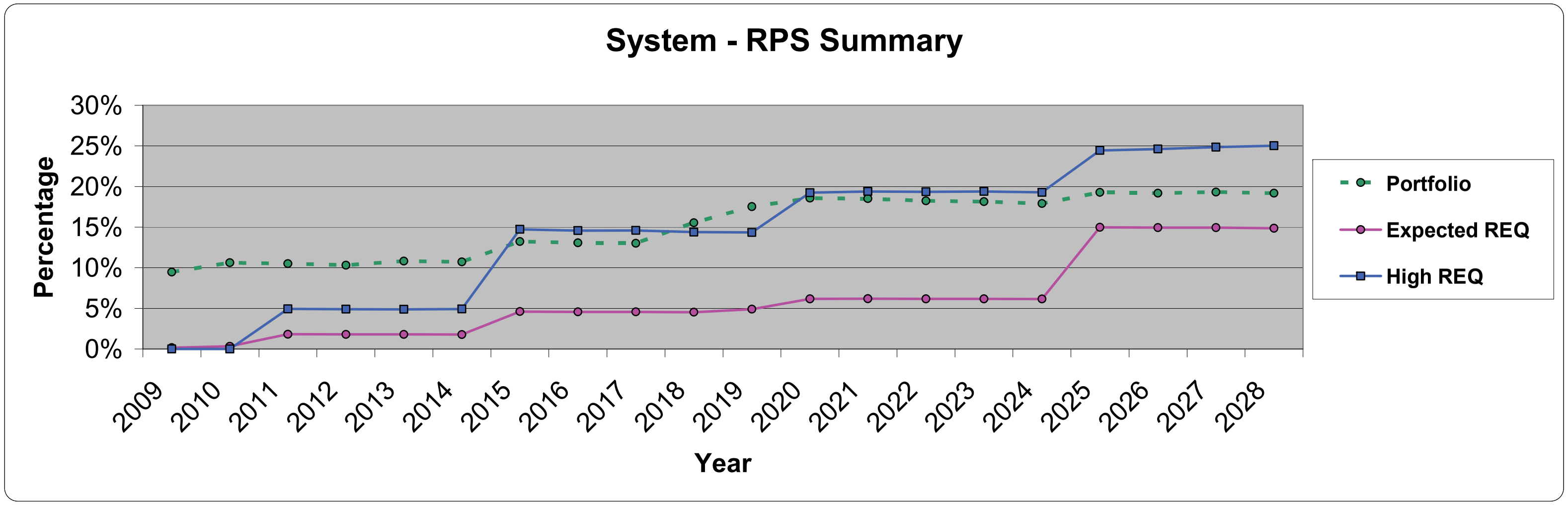


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 5B_CCCT

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,076	25,936	29,823	33,735	38,638	44,285	49,962	55,654	61,294	66,950	72,600	73,098	73,573	74,096	74,607
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	93	270	326	196	184	166	149	141	142	137	135	132
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,538	2,702	1,844	1,557	1,670	968	222	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,861**	**22,832**	**26,856**	**29,730**	**32,619**	**35,672**	**40,466**	**46,281**	**51,126**	**56,060**	**61,460**	**67,099**	**72,741**	**73,239**	**73,710**	**74,230**	**74,739**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	3,861	3,887	3,912	4,903	5,647	5,677	5,692	5,640	5,656	5,651	5,755	5,776	5,881	5,902
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,360	1,378	1,387	1,951	2,373	2,390	2,396	2,365	2,370	2,330	2,397	2,414	2,481	2,498
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	417	420	421	602	733	731	730	720	720	719	729	723	733	728
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,244	2,266	2,277	2,412	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,892**	**6,330**	**6,427**	**8,089**	**8,162**	**8,229**	**9,986**	**11,428**	**12,230**	**12,290**	**12,220**	**12,273**	**12,258**	**13,293**	**13,353**	**13,575**	**13,648**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	13%	16%	18%	19%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

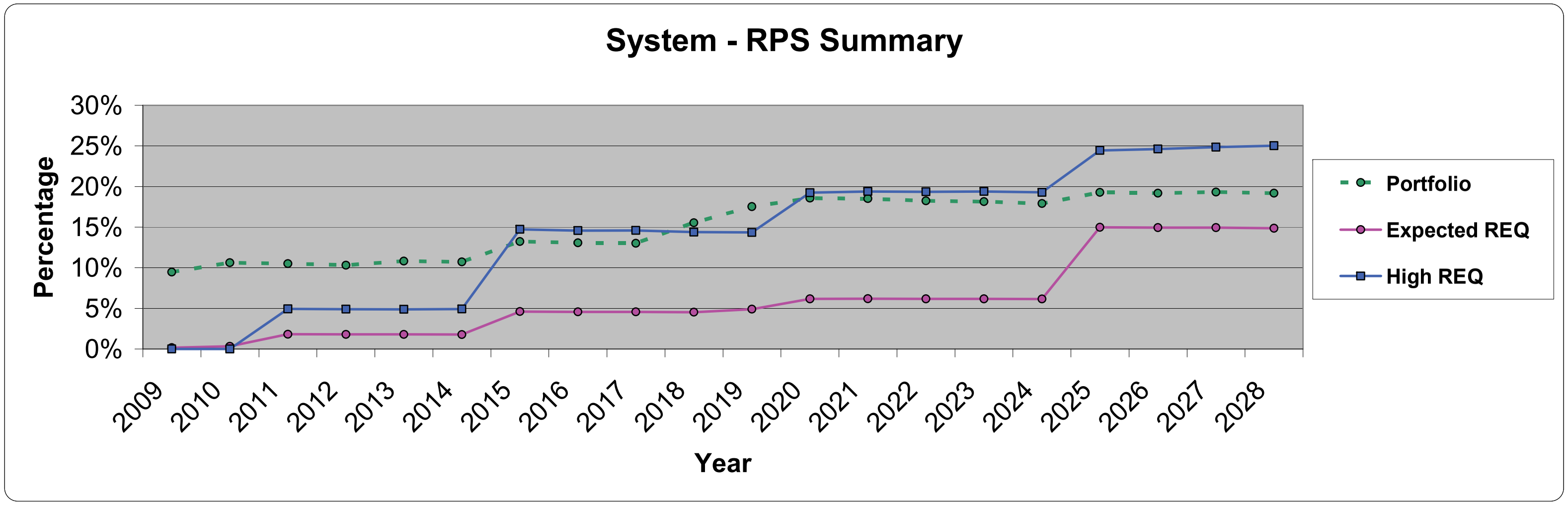


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II, Fixed CCCT)

System - RPS Report - Case # 5B_CCCT-WC

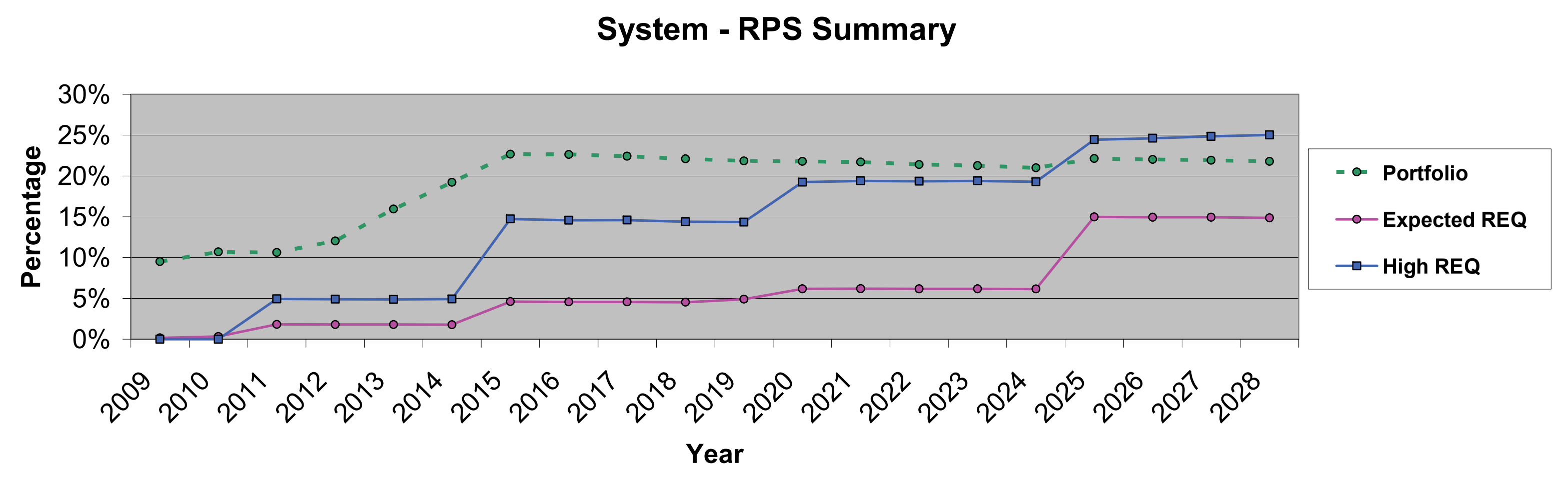
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,716	11,920	15,139	18,572	22,076	25,936	29,823	33,735	38,638	44,285	49,962	55,653	61,294	66,949	72,600	73,097	73,573	74,095	74,607
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	416	256	94	93	270	326	196	184	166	149	141	142	137	135	132
Oregon	1,376	2,519	2,952	3,381	3,883	4,364	3,538	2,702	1,844	1,557	1,670	968	221	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,535**	**15,342**	**18,861**	**22,832**	**26,856**	**29,730**	**32,619**	**35,672**	**40,465**	**46,280**	**51,126**	**56,059**	**61,460**	**67,099**	**72,741**	**73,239**	**73,710**	**74,230**	**74,739**
Adjusted Qualifying Renewables																				
Utah	2,950	3,166	3,204	3,219	3,433	3,503	3,860	3,887	3,912	4,903	5,647	5,677	5,692	5,640	5,656	5,651	5,755	5,776	5,881	5,902
Other (ID,WY)	823	1,022	1,034	1,050	1,142	1,164	1,360	1,378	1,387	1,951	2,373	2,390	2,396	2,365	2,370	2,330	2,397	2,414	2,481	2,498
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	333	417	420	421	602	733	731	730	720	720	719	729	723	733	728
Oregon	982	1,143	1,133	1,137	1,222	1,214	2,228	2,244	2,266	2,277	2,412	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**5,807**	**5,848**	**5,892**	**6,330**	**6,427**	**8,089**	**8,162**	**8,229**	**9,986**	**11,428**	**12,230**	**12,290**	**12,220**	**12,273**	**12,258**	**13,293**	**13,353**	**13,575**	**13,648**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	13%	13%	13%	16%	18%	19%	19%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description
CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II, Fixed CCCT-WC)

System - RPS Report - Case # 8B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,560	8,742	11,973	15,613	20,324	25,996	32,671	39,457	46,267	53,089	59,935	66,812	73,703	80,543	87,399	94,249	95,862	97,453	99,008	100,551
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	303	479	423	686	1,046	1,166	1,137	1,151	1,150	895	634	623	604	588	579	565	545	527	509
Oregon	1,382	2,536	2,984	3,668	4,939	6,709	7,545	8,415	9,258	10,099	10,916	10,913	10,864	10,757	10,613	10,416	9,332	8,185	6,964	5,670
Cumulative Surplus Credit Bank Balance	**6,942**	**11,581**	**15,436**	**19,703**	**25,949**	**33,750**	**41,383**	**49,009**	**56,676**	**64,338**	**71,746**	**78,359**	**85,190**	**91,904**	**98,599**	**105,244**	**105,758**	**106,183**	**106,499**	**106,731**
Adjusted Qualifying Renewables																				
Utah	2,959	3,182	3,231	3,640	4,712	5,672	6,675	6,786	6,810	6,822	6,846	6,877	6,891	6,840	6,855	6,850	6,871	6,892	6,913	6,934
Other (ID,WY)	828	1,031	1,049	1,285	1,861	2,400	2,975	3,048	3,062	3,057	3,065	3,089	3,096	3,065	3,073	3,030	3,055	3,079	3,103	3,126
California	88	176	185	194	204	213	225	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	266	303	298	368	562	729	931	949	950	952	952	950	949	939	939	938	932	927	921	916
Oregon	989	1,154	1,149	1,391	1,991	2,502	3,065	3,114	3,109	3,119	3,117	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,130**	**5,846**	**5,912**	**6,879**	**9,329**	**11,516**	**13,870**	**14,130**	**14,174**	**14,202**	**14,243**	**14,346**	**14,409**	**14,340**	**14,394**	**14,377**	**15,271**	**15,338**	**15,417**	**15,496**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	10%	11%	11%	12%	16%	19%	23%	23%	22%	22%	22%	22%	22%	21%	21%	21%	22%	22%	22%	22%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

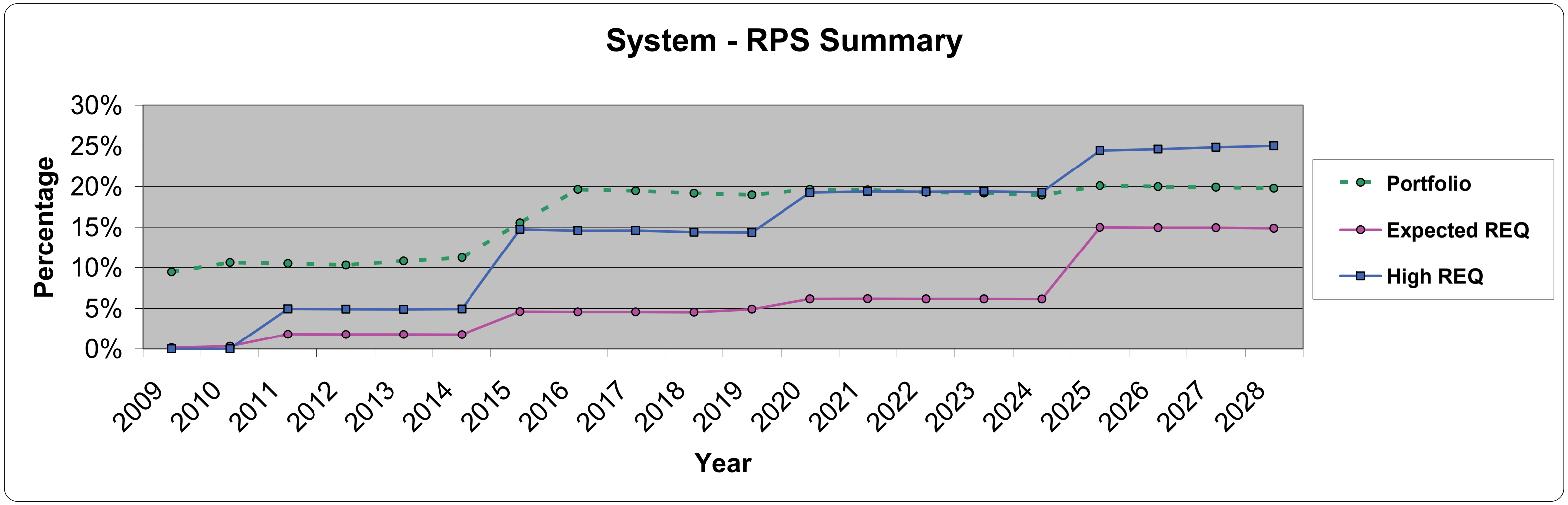

System - RPS Summary

Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 9B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,139	18,573	22,206	26,869	32,854	38,863	44,884	50,930	57,006	63,097	69,136	75,191	81,241	82,053	82,844	83,598	84,341
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	341	376	440	427	623	859	857	603	342	330	312	295	287	272	253	235	217
Oregon	1,376	2,519	2,952	3,381	3,883	4,442	4,089	4,488	4,860	5,231	5,578	5,109	4,594	4,022	3,415	2,754	1,209	-	-	-
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**18,861**	**22,832**	**27,088**	**31,385**	**37,965**	**44,582**	**50,972**	**57,110**	**62,456**	**68,021**	**73,470**	**78,901**	**84,281**	**83,534**	**83,096**	**83,833**	**84,557**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,219	3,433	3,633	4,663	5,985	6,009	6,021	6,046	6,076	6,091	6,040	6,055	6,050	6,070	6,091	6,112	6,134
Other (ID,WY)	822	1,022	1,034	1,050	1,143	1,238	1,821	2,586	2,599	2,595	2,603	2,623	2,629	2,598	2,604	2,563	2,583	2,602	2,621	2,639
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	300	293	292	328	356	563	803	804	806	806	803	803	793	793	792	786	781	775	770
Oregon	982	1,144	1,133	1,137	1,222	1,291	2,228	2,643	2,639	2,648	2,647	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**5,893**	**6,331**	**6,732**	**9,498**	**12,249**	**12,294**	**12,323**	**12,365**	**12,934**	**12,995**	**12,926**	**12,978**	**12,963**	**13,852**	**13,914**	**13,988**	**14,062**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	11%	11%	16%	20%	19%	19%	19%	20%	20%	19%	19%	19%	20%	20%	20%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

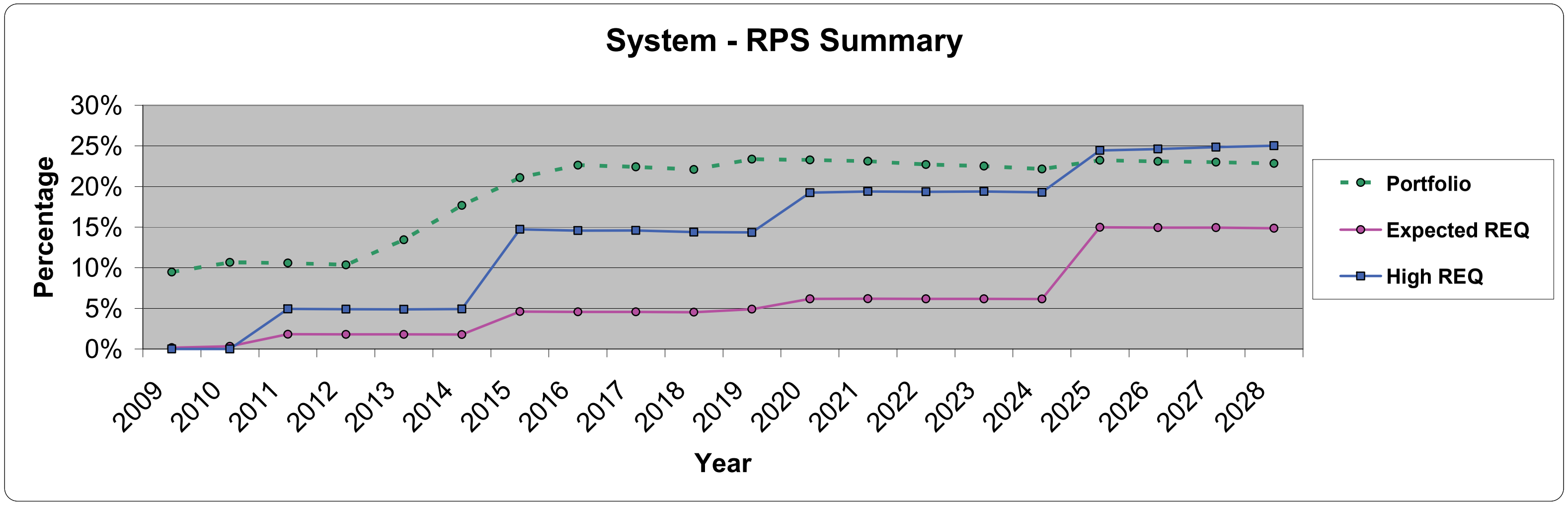


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 10B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,724	11,947	15,177	19,264	24,544	30,806	37,592	44,402	51,224	58,492	65,790	73,103	80,365	87,642	94,914	96,948	98,961	100,937	102,902
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	476	347	498	860	1,019	1,062	1,151	1,150	972	788	777	758	742	733	719	699	681	663
Oregon	1,377	2,525	2,968	3,404	4,299	5,836	6,428	7,299	8,141	8,982	10,047	10,290	10,485	10,623	10,723	10,772	9,930	9,023	8,040	6,981
Cumulative Surplus Credit Bank Balance	**6,929**	**11,550**	**15,390**	**18,927**	**24,060**	**31,240**	**38,253**	**45,952**	**53,694**	**61,355**	**69,510**	**76,868**	**84,365**	**91,746**	**99,106**	**106,419**	**107,597**	**108,683**	**109,658**	**110,547**
Adjusted Qualifying Renewables																				
Utah	2,951	3,173	3,222	3,230	4,087	5,280	6,262	6,786	6,810	6,822	7,268	7,298	7,313	7,262	7,277	7,272	7,292	7,313	7,334	7,356
Other (ID,WY)	823	1,026	1,044	1,056	1,510	2,177	2,738	3,048	3,062	3,057	3,309	3,334	3,343	3,312	3,320	3,276	3,304	3,331	3,357	3,383
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	296	294	448	657	855	949	950	952	1,029	1,027	1,026	1,016	1,016	1,015	1,009	1,004	998	993
Oregon	983	1,148	1,144	1,144	1,615	2,269	2,820	3,114	3,109	3,119	3,364	3,339	3,329	3,291	3,282	3,260	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,824**	**5,891**	**5,918**	**7,864**	**10,597**	**12,898**	**14,130**	**14,174**	**14,202**	**15,233**	**15,334**	**15,349**	**15,222**	**15,239**	**15,171**	**16,018**	**16,088**	**16,169**	**16,251**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	13%	18%	21%	23%	22%	22%	23%	23%	23%	23%	23%	22%	23%	23%	23%	23%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

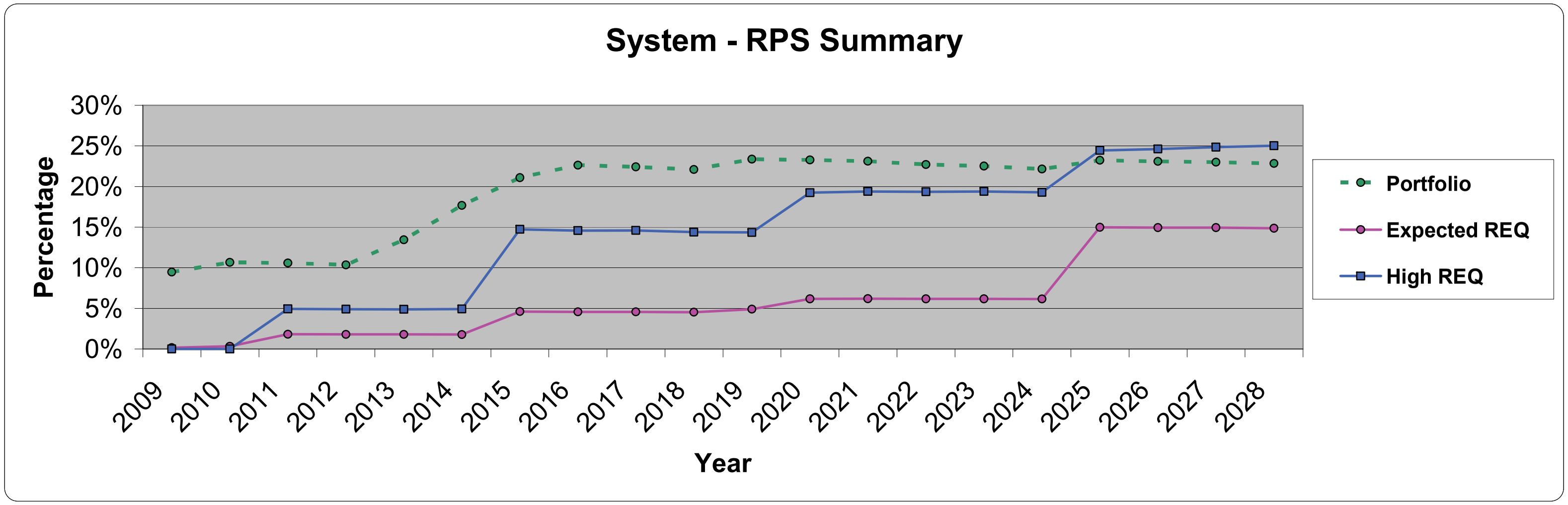


Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 17b

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,724	11,947	15,177	19,264	24,544	30,806	37,592	44,402	51,224	58,492	65,790	73,103	80,365	87,642	94,914	96,948	98,961	100,937	102,902
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	476	347	498	860	1,019	1,062	1,151	1,150	972	788	777	758	742	733	719	699	681	663
Oregon	1,377	2,525	2,968	3,404	4,299	5,836	6,428	7,299	8,141	8,982	10,047	10,290	10,485	10,623	10,723	10,772	9,930	9,023	8,040	6,981
Cumulative Surplus Credit Bank Balance	**6,929**	**11,550**	**15,390**	**18,927**	**24,060**	**31,240**	**38,253**	**45,952**	**53,694**	**61,355**	**69,510**	**76,868**	**84,365**	**91,746**	**99,106**	**106,419**	**107,597**	**108,683**	**109,658**	**110,547**
Adjusted Qualifying Renewables																				
Utah	2,951	3,173	3,222	3,230	4,087	5,280	6,262	6,786	6,810	6,822	7,268	7,298	7,313	7,262	7,277	7,272	7,292	7,313	7,334	7,356
Other (ID,WY)	823	1,026	1,044	1,056	1,510	2,177	2,738	3,048	3,062	3,057	3,309	3,334	3,343	3,312	3,320	3,276	3,304	3,331	3,357	3,383
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	296	294	448	657	855	949	950	952	1,029	1,027	1,026	1,016	1,016	1,015	1,009	1,004	998	993
Oregon	983	1,148	1,144	1,144	1,615	2,269	2,820	3,114	3,109	3,119	3,364	3,339	3,329	3,291	3,282	3,260	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,111**	**5,824**	**5,891**	**5,918**	**7,864**	**10,597**	**12,898**	**14,130**	**14,174**	**14,202**	**15,233**	**15,334**	**15,349**	**15,222**	**15,239**	**15,171**	**16,018**	**16,088**	**16,169**	**16,251**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	13%	18%	21%	23%	22%	22%	23%	23%	23%	23%	23%	22%	23%	23%	23%	23%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

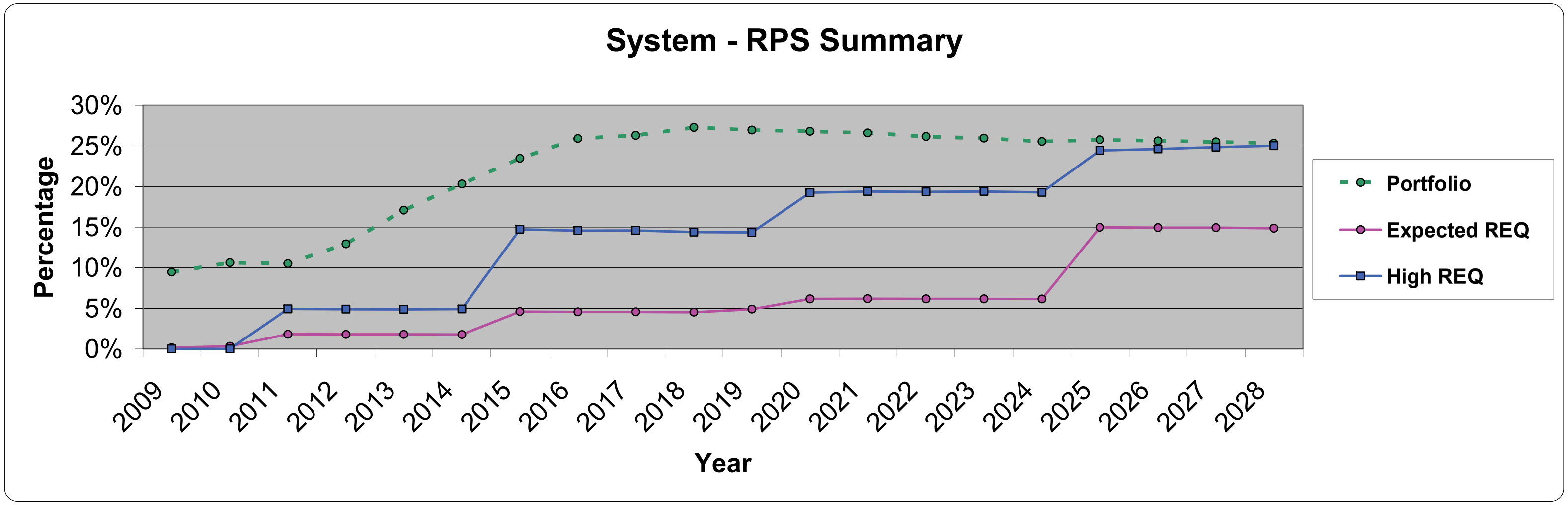


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Medium - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 18B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,715	11,920	15,778	20,772	26,725	33,602	41,247	49,090	57,320	65,575	73,859	82,159	90,407	98,670	106,929	109,950	112,949	115,912	118,863
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	300	471	458	778	1,149	1,255	1,331	1,497	1,595	1,409	1,149	1,137	1,118	1,102	1,094	1,079	1,059	1,041	1,024
Oregon	1,376	2,519	2,952	3,767	5,208	7,145	8,101	9,476	10,925	12,594	14,237	15,056	15,824	16,535	17,206	17,827	17,552	17,206	16,780	16,271
Cumulative Surplus Credit Bank Balance	**6,925**	**11,534**	**15,343**	**20,003**	**26,758**	**35,019**	**42,958**	**52,053**	**61,512**	**71,510**	**81,221**	**90,063**	**99,120**	**108,060**	**116,978**	**125,849**	**128,581**	**131,215**	**133,733**	**136,158**
Adjusted Qualifying Renewables																				
Utah	2,949	3,166	3,204	3,858	4,994	5,953	6,877	7,644	7,844	8,230	8,254	8,285	8,299	8,248	8,263	8,258	8,279	8,300	8,321	8,342
Other (ID,WY)	822	1,022	1,034	1,407	2,020	2,560	3,090	3,542	3,659	3,868	3,878	3,908	3,918	3,888	3,897	3,852	3,886	3,919	3,951	3,983
California	88	176	185	194	204	213	233	263	270	286	286	336	339	341	345	348	352	354	357	360
Washington	264	300	293	408	613	780	968	1,106	1,139	1,209	1,209	1,207	1,206	1,197	1,196	1,195	1,190	1,184	1,179	1,173
Oregon	982	1,144	1,133	1,523	2,161	2,669	3,184	3,619	3,715	3,947	3,943	3,914	3,902	3,864	3,853	3,832	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,106**	**5,807**	**5,849**	**7,391**	**9,992**	**12,177**	**14,352**	**16,174**	**16,627**	**17,540**	**17,571**	**17,649**	**17,665**	**17,538**	**17,555**	**17,486**	**17,767**	**17,843**	**17,930**	**18,018**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	13%	17%	20%	23%	26%	26%	27%	27%	27%	27%	26%	26%	26%	26%	26%	26%	25%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%

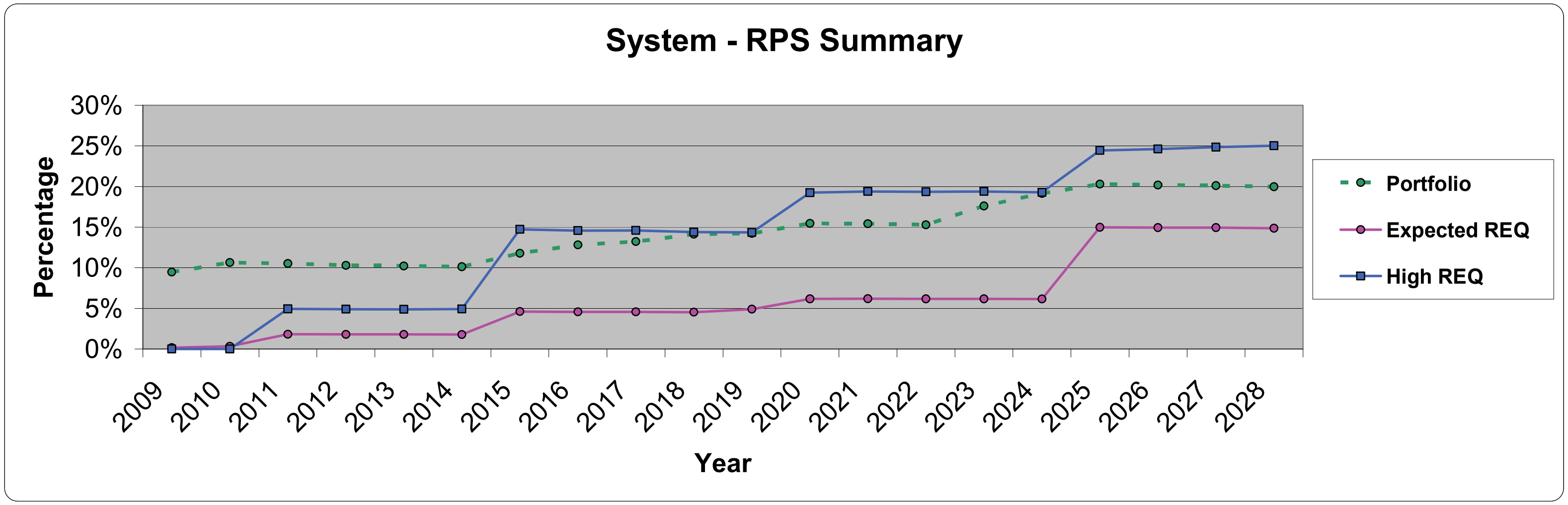


Study Description

CO2 Type = CO2 tax, CO2 Cost = $70, Gas = Low - Oct 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

System - RPS Report - Case # 47B

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,552	8,724	11,936	15,153	18,436	21,787	25,117	28,911	32,895	37,282	41,698	46,016	50,325	54,576	60,027	66,160	67,057	67,930	68,768	69,593
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	301	474	342	348	361	132	30	89	189	7	-	-	-	36	192	303	283	265	247
Oregon	1,377	2,524	2,961	3,389	3,801	4,192	3,052	2,161	1,346	755	146	-	-	-	-	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,929**	**11,549**	**15,370**	**18,884**	**22,586**	**26,341**	**28,300**	**31,102**	**34,330**	**38,226**	**41,851**	**46,016**	**50,325**	**54,576**	**60,062**	**66,353**	**67,360**	**68,213**	**69,033**	**69,840**
Adjusted Qualifying Renewables																				
Utah	2,952	3,172	3,212	3,217	3,283	3,351	3,329	3,794	3,984	4,387	4,417	4,447	4,451	4,441	5,451	6,134	6,154	6,173	6,196	6,216
Other (ID,WY)	824	1,026	1,038	1,049	1,058	1,077	1,056	1,325	1,430	1,653	1,663	1,675	1,673	1,664	2,250	2,612	2,632	2,651	2,671	2,689
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	265	301	294	291	301	305	370	403	434	507	632	636	640	644	682	807	802	796	791	785
Oregon	984	1,147	1,137	1,136	1,132	1,123	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,112**	**5,821**	**5,866**	**5,888**	**5,978**	**6,070**	**7,207**	**7,998**	**8,357**	**9,077**	**9,274**	**10,190**	**10,236**	**10,245**	**11,911**	**13,111**	**14,001**	**14,060**	**14,138**	**14,210**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	11%	10%	10%	10%	12%	13%	13%	14%	14%	15%	15%	15%	18%	19%	20%	20%	20%	20%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description

CO2 Type = CO2 compliance scenario, CO2 Cost = , Gas = Medium - Oct 2008, Load Growth = Medium, Renewable Std = Optimized RPS-compliant renewables, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II)

Portfolio Summary Tables

Notes for the Portfolio Resource Tables

- Nameplate Capacity, MW
  - Nameplate capacities are reported for wind resources
  - Gas resource capacities reflect average annual capability rather than the generator nameplate. For combined-cycle resources, the values shown approximate the July maximum capabilities
  - Class 2 DSM resources (energy efficiency) capacities reflect summer peak values
  - Capacities shown for the coal plant CCS (carbon capture and sequestration) retrofits represent replacement capacity for an existing unit; the replacement capacity is smaller than the original unit size, which is due to a capacity penalty for capturing the CO_2
  - Capacities for all other resources represent maximum summer capabilities
- Swift 1 Upgrades – The three Swift upgrade projects (25 MW each) are shown under the year for which they enter commercial service (2012, 2013, and 2014); however, the planned in-service dates occur after the system peaks for these years. They are available to support the summer peak load in 2013, 2014, and 2015, respectively.
- High Plains and Duke PPA Wind Projects – The High Plains wind project has an October December 2009 in-service date, and is therefore shown under the year for which it enters commercial service (2009); the Duke project has a December 2009 in-service date, but is modeled with a start date of January 1, 2010, and is therefore shown in the year it is available to support the summer peak load (2010).
- Front Office Transactions – For the 10- and 20-year total columns, the megawatts represent the annual average values, as these resources are not accumulative over the planning period.
- Growth Stations – For the 20 Year column "Growth Resources" reflect an 8-year average for 2021-2028, the period that these resources are available for selection by the System Optimizer model.
- The resources shown with a zero are less than 0.5 megawatts
- Short-term resource totals at the bottom of the tables comprise the sum of front office transactions and growth resources

Table A.18 – Planned Resources

		Capacity, MW										Resource Total
	Planned Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
East												
	East PPA	-	-	-	201	-	-	-	-	-	-	**201**
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	**128**
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	**99**
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	**99**
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	**205**
West												
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	**42**
	Swift Hydro Upgrades	-	-	-	25	25	25	-	-	-	-	**75**
	Wind PPA	45	20	-	-	-	-	-	-	-	-	**65**
	Total Planned Resources	**172**	**222**	**82**	**292**	**49**	**49**	**10**	**18**	**10**	**10**	**913**

Note: The 2012 RFP Lake Side resource was removed as a planned resource in February 2009.

Case 01

PVRR: $20,045

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Total Wind	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	198	198
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	0
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	4.2	-	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	11.4	18.5	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1 & 3 Total	25	50.0	40	30	14	10	62	36	10	10	-	-	-	-	-	-	-	-	-	-	287	287
	DSM, Class 2, GO	-	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	11	27
	DSM, Class 2, UT	6	37.5	34	36	39	39	43	40	40	46	45	46	40	42	42	43	43	51	51	48	361	810
	DSM, Class 2, WY	-	-	-	-	8	8	8	8	8	8	8	8	8	8	9	9	9	9	9	9	47	133
	DSM, Class 2 Total	6	37.5	34	38	48	48	52	50	49	55	55	55	50	52	52	53	53	61	62	58	418	970
	FOT Utah Q3	-	-	-	-	50	50	50	50	-	50	50	50	-	-	50	50	50	50	50	-	25	30
	FOT Mead Q3	-	-	-	-	-	-	-	-	580	600	600	600	600	600	600	600	600	600	600	600	118	359
	FOT Mona/Nevada Utah Border	-	-	-	-	44	166	200	200	-	82	129	200	-	-	-	-	-	-	-	-	69	51
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	168	222	218	173	220	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	166	138	322	375	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62	307	-	-	-	N/A	46
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	2	-	-	-	-	-	-	-	-	-	24	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	20	5	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 2, WA	-	2	3	3	3	3	3	3	3	2	3	2	2	2	2	2	2	2	2	2	23	47
	DSM, Class 2, WM	-	-	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	231	430
	DSM, Class 2, YA	3	5	4	4	4	4	4	4	5	5	5	5	5	5	5	4	5	5	5	5	43	89
	DSM, Class 2 Total	3	6.2	37	37	37	37	37	37	38	27	27	27	27	27	27	26	27	27	27	27	298	567
	FOT COB Flat	-	-	301	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	248	293
	FOT MidColumbia Q3	-	-	-	362	400	400	400	400	170	400	400	400	400	400	400	400	400	400	400	400	253	327
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	122	128	135	138	129	130	132	219	N/A	142
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	284	283	109	-	-	230	200	893	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	119	217	120	97	196	287	329	N/A	171
	Annual Additions, Long Term Resources	195	279	167	988	151	148	186	411	106	100	88	82	76	79	80	79	81	88	89	85		
	Annual Additions, Short Term Resources	-	-	301	801	933	1,055	989	939	1,039	1,422	1,566	1,638	1,794	1,918	2,066	2,146	2,327	2,489	2,651	2,828		
	Total Annual Additions	195	279	468	1,789	1,085	1,203	1,175	1,350	1,145	1,522	1,654	1,720	1,871	1,997	2,146	2,225	2,407	2,577	2,739	2,914		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 02

PVRR: $21,512

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	628	-	-	641
	Total Wind	99	99	-	-	-	-	-	-	-	140	160	-	-	-	14	-	-	-	628	-	338	1,139
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	-	2	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	41	46.1	42	42	43	44	43	41	46	48	47	48	49	51	52	52	50	53	57	55	436	950
	DSM, Class 2, WY	1	3.1	6	8	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	67	164
	DSM, Class 2 Total	43	50.8	49	52	53	54	53	51	57	58	58	59	60	62	64	64	63	66	69	67	520	1,151
	FOT Utah Q3	-	-	-	-	-	-	9	44	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	411	421	427	480	480	590	480	480	600	600	600	89	302
	FOT Mona/Nevada Utah Border	-	-	-	120	200	200	200	200	87	-	-	-	82	98	200	128	200	200	200	200	101	116
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	-	5
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	35	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	370	663
	FOT COB Flat	-	-	219	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	239	288
	FOT Mid Columbia Flat	-	-	-	-	-	299	400	-	170	213	250	-	-	-	-	-	-	-	172	173	108	84
	FOT MidColumbia Q3	-	-	-	155	178	-	-	400	-	-	-	259	-	-	-	-	-	-	-	-	73	50
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	-	-	50	50	50	50	50	50	50	50	50	30	38
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	141	142	115	149	117	163	198	168	N/A	149
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	89	-	262	344	372	298	635	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	127	132	172	124	172	133	140	-	N/A	125
	Annual Additions, Long Term Resources	258	317	178	998	185	149	110	377	114	847	249	91	93	94	109	96	95	98	729	98		
	Annual Additions, Short Term Resources	-	-	219	714	817	938	949	933	1,027	863	1,008	1,074	1,217	1,329	1,464	1,530	1,700	1,856	1,995	2,164		
	Total Annual Additions	258	317	397	1,712	1,002	1,088	1,059	1,310	1,140	1,710	1,257	1,164	1,310	1,423	1,574	1,626	1,795	1,954	2,724	2,262		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 3

PVRR: **$19,503**

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	WY Pulverized Coal	-	-	-	-	-	-	-	-	-	790	-	-	-	-	-	-	-	-	-	-	790	790
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	138	162	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	237	63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	97	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	588	212	-	-	-	-	-	-	-	-	-	588	800
	Wind, WYSW, 35	-	303	60	129	-	135	451	223	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	499	400	192	-	135	750	223	138	750	712	-	-	-	-	-	-	-	-	-	3,186	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	47	55	49	49	49	51	51	50	53	51	55	55	56	58	59	73	64	55	57	55	505	1,092
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	72	172
	DSM, Class 2 Total	50	61	57	59	60	62	62	61	64	63	67	67	68	70	71	85	77	68	69	67	599	1,308
	FOT Mona Q3	-	-	-	68	124	200	200	200	48	-	-	-	-	-	64	124	-	17	200	200	84	72
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	166	167	480	154	271	480	480	390	480	600	600	65	237
	FOT Utah Q3	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	Total Wind	45	120	100	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	368
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	20	291	496
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	60	125
	DSM, Class 2 Total	37	38	40	40	39	40	40	40	40	30	30	30	30	30	30	31	30	30	30	30	383	684
	FOT COB Flat	-	-	-	-	-	-	-	-	-	-	338	-	338	338	338	-	-	-	-	338	-	84
	FOT COB Q3	-	-	129	389	400	389	289	239	239	239	-	77	-	-	-	338	338	338	338	-	232	187
	FOT Mid Columbia Flat	-	-	-	144	125	138	170	400	157	199	235	-	-	-	-	-	-	-	316	246	133	106
	FOT MidColumbia Q3	-	-	-	-	-	-	-	-	-	-	-	244	-	-	-	-	-	-	-	-	-	12
	FOT West Main Q3	-	-	-	-	-	21	50	50	43	-	-	-	-	-	-	-	-	-	50	50	16	13
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	247	208	99	-	99	160	53	187	N/A	132
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	89	97	-	-	392	423	65	169	N/A	154
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	114	119	172	257	173	119	45	-	N/A	125
	Annual Additions, Long Term Resources	267	829	693	1,301	261	300	895	375	261	1,658	808	97	98	99	101	116	107	98	100	98		
	Annual Additions, Short Term Resources	-	-	129	601	648	749	709	891	967	604	739	800	941	1,049	1,180	1,231	1,392	1,548	1,702	1,872		
	Total Annual Additions	267	829	823	1,902	909	1,049	1,604	1,266	1,227	2,261	1,547	897	1,039	1,148	1,281	1,347	1,499	1,646	1,802	1,969		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 4

PVRR: $34,612

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Total Wind	99	99	-	-	-	-	140	-	160	-	-	-	-	-	-	-	-	-	-	-	498	498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	-	-	-	-	8	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	16	37
	DSM, Class 2, UT	37	46	42	42	43	44	43	41	45	47	47	48	49	51	52	52	50	53	54	52	431	939
	DSM, Class 2, WY	-	3	6	8	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	66	162
	DSM, Class 2 Total	38	50	49	52	53	54	53	51	56	58	58	59	60	62	64	64	63	66	66	64	513	1,138
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	104	3	-	-	-	-	-	-	-	-	-	10	5
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	288	491
	DSM, Class 2, YA	4	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	369	662
	FOT COB Flat	-	-	-	213	-	222	102	189	147	239	338	275	231	201	190	186	329	338	321	-	111	176
	FOT COB Q3	-	-	-	-	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	299	23	26
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	90	119	148	146	-	-	-	-	-	-	-	-	21	25
	FOT MidColumbia Q3	-	-	-	123	96	99	94	89	-	-	-	-	-	-	-	-	-	-	-	-	50	25
	FOT West Main Q3	-	-	-	-	-	-	-	-	-	13	-	-	50	50	50	-	-	-	18	50	1	12
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	15	14	33	31	43	N/A	18
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	144	140	137	101	105	82	83	68	N/A	108
	Annual Additions, Long Term Resources	253	316	178	998	182	149	252	118	275	107	89	90	93	94	96	96	438	96	96	94		
	Annual Additions, Short Term Resources	-	-	-	335	322	321	197	278	237	475	488	421	425	391	381	302	448	452	453	461		
	Total Annual Additions	253	316	178	1,333	504	471	449	396	512	582	577	511	518	485	476	398	887	548	549	555		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05

PVRR: $40,526

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	750	400	-	150	-	-	-	-	-	-	-	750	1,300
	Total Wind	99	99	-	-	-	-	300	-	-	750	400	-	150	-	-	-	-	-	-	-	1,248	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	446	970
	DSM, Class 2, WY	-	2.6	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	67	164
	DSM, Class 2 Total	42	50.3	49	52	55	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	531	1,172
	FOT Utah Q3	-	-	-	-	-	-	-	25	-	-	-	-	50	50	-	-	-	-	50	-	2	9
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Mona/Nevada Utah Border	-	-	-	121	200	200	200	200	64	200	200	200	200	200	200	200	200	200	200	200	119	159
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	199	200	198	219	-	-	183	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	2	106	249	341	-	-	111	-	N/A	101
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	3	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	4	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	370	663
	FOT COB Flat	-	-	220	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	201	252
	FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	171	276	313	379	71	151	189	141	400	400	400	400	45	165
	FOT MidColumbia Q3	-	-	-	156	178	296	396	400	-	-	-	-	-	-	-	-	-	-	-	-	143	71
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	118	123	130	133	124	135	153	149	N/A	133
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	498	215	887	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	80	-	-	-	194	243	319	164	N/A	125
	Annual Additions, Long Term Resources	256	317	178	998	187	152	415	385	118	858	490	91	242	94	95	95	446	97	98	97		
	Annual Additions, Short Term Resources	-	-	220	716	817	935	936	914	1,004	1,365	1,500	1,566	1,707	1,818	1,954	2,021	2,306	2,463	2,618	2,788		
	Total Annual Additions	256	317	398	1,713	1,004	1,088	1,351	1,299	1,122	2,223	1,990	1,657	1,949	1,912	2,049	2,116	2,752	2,559	2,716	2,885		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 06

PVRR: $48,140

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCCT H 2x1	-	-	-	-	-	-	-	-	-	475	-	475	-	-	-	-	-	-	-	-	475	950
	IC Aero	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	354	-	251	-	-	696	-	-	-	-	-	-	-	604	1,300
	Total Wind	99	99	-	-	-	140	160	354	-	251	-	-	696	-	-	-	-	-	-	-	1,102	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	4	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	101	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	40
	DSM, Class 2, UT	43	48.7	44	48	49	52	51	52	52	51	55	54	56	58	59	73	64	62	60	60	490	1,091
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	172
	DSM, Class 2 Total	45	53.3	52	58	59	62	61	63	63	61	66	65	68	70	71	85	77	75	73	73	579	1,303
	Fuel Cell	-	-	-	-	5	5	-	30	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	-	18	50	-	50	-	-	-	-	50	50	50	50	50	50	50	50	12	26
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	497	600	480	600	600	600	600	600	600	600	600	98	343
	FOT Mona/Nevada Utah Border	-	39	79	200	200	200	99	200	166	200	200	144	200	200	200	200	200	200	200	200	138	166
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	95	114	174	122	99	199	197	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	63	249	-	-	470	217	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	21	127	211	129	-	249	263	N/A	125
West																							
	CCCT F 2x1	-	-	-	-	-	-	627	-	-	-	-	-	-	-	-	-	-	-	-	-	627	627
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	-	-	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	2	-	-	-	-	-	-	-	24	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 06

PVRR: $48,140

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	21	21	21	21	21	290	496
DSM, Class 2, YA	5	6	6	5	6	6	6	6	5	6	6	6	6	6	7	7	7	7	7	7	56	122
DSM, Class 2 Total	35	37.2	39	39	39	40	40	40	39	29	30	30	30	29	30	31	30	30	31	31	378	680
FOT COB Flat	-	-	389	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	218	261
FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	244	302	395	370	400	400	400	400	400	400	400	400	55	225
FOT MidColumbia Q3	-	-	-	202	400	400	206	400	-	-	-	-	-	-	-	-	-	-	-	-	161	80
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	35	169	190	182	184	297	442	502	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381	763	147	709	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	40	148	64	417	430	445	456	N/A	250
Annual Additions, Long Term Resources	266	327	188	1,272	214	506	940	546	123	836	98	572	801	101	102	118	107	106	104	104		
Annual Additions, Short Term Resources	-	39	469	841	1,058	1,089	644	939	1,179	1,288	1,582	1,381	1,673	1,962	2,279	2,517	2,870	3,226	3,591	3,982		
Total Annual Additions	266	366	656	2,113	1,271	1,595	1,584	1,485	1,302	2,124	1,681	1,953	2,474	2,063	2,382	2,635	2,977	3,332	3,695	4,086		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 7

PVRR: $34,582

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	27	400	207	590	-	76	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	27	400	346	750	-	76	-	-	-	-	-	-	-	-	-	-	-	1,798	1,798
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	1	-	-	-	8	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	49	44	45	45	46	46	45	47	48	47	48	54	56	52	52	50	53	54	55	457	978
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	70	166
	DSM, Class 2 Total	45	53	52	55	56	56	56	56	58	59	58	59	65	67	64	64	63	66	66	67	544	1,183
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	2	1
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	100	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	-	25	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	1	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
	DSM, Class 2, YA	5	6	6	5	5	6	6	5	6	6	6	6	6	6	7	7	7	7	7	7	56	121
	DSM, Class 2 Total	36	37	39	39	39	39	39	39	40	29	30	30	30	29	30	31	30	30	30	30	376	675
	FOT COB Flat	-	-	-	-	203	187	36	118	52	239	243	177	180	146	134	81	105	113	115	-	83	106
	FOT COB Q3	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	20	30
	FOT Mid Columbia Flat	-	-	-	-	89	92	87	82	82	111	139	138	-	-	-	-	-	-	-	-	54	41
	FOT MidColumbia Q3	-	-	-	121	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	6
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	N/A	1
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	136	131	132	107	109	105	104	89	N/A	114
	Annual Additions, Long Term Resources	261	320	181	1,028	686	499	890	123	219	209	90	91	97	99	96	97	94	96	97	444		
	Annual Additions, Short Term Resources	-	-	-	321	292	279	123	201	134	370	382	315	316	277	267	187	214	218	218	501		
	Total Annual Additions	261	320	181	1,349	978	778	1,013	324	352	579	473	406	413	377	363	285	308	314	315	944		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 8

PVRR: $41,372

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	43.6	33	24.5	1.8	14.1	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	193	107	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	264	300	146	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	264	300	286	750	193	158	249	-	-	-	-	-	-	-	-	-	-	2,398	2,398
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	5	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	66	66
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	16	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	49	51	51	50	52	51	55	54	54	56	58	62	59	55	57	56	484	1,049
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	171
	DSM, Class 2 Total	45	54	52	55	60	62	62	61	64	63	66	65	66	68	70	74	72	68	70	68	577	1,264
	FOT Mona Q3	-	-	-	89	189	200	200	200	78	200	200	200	200	200	200	200	200	200	200	200	116	158
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	40	-	-	-	-	-	-	5	4
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	153	148	145	163	-	11	35	83	N/A	92
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	167	-	-	-	-	N/A	31
West																							
	Coal Plant Turbine Upgrades	-	9	8.9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	22	22
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	496
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	56	122
	DSM, Class 2 Total	36	37	39	39	39	39	39	40	40	30	30	30	30	29	30	31	30	30	30	30	378	678
	FOT COB Flat	-	-	200	-	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	199	251
	FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	39	39
	FOT Mid Columbia Flat	-	-	-	-	130	220	281	400	163	269	313	373	18	331	400	265	400	400	400	293	146	233
	FOT MidColumbia Q3	-	-	-	154	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	100	114	132	112	119	128	208	N/A	126
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82	172	464	413	870	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	246	2	14	-	291	137	309	-	N/A	125
	Annual Additions, Long Term Resources	263	327	187	1,277	698	450	908	394	283	362	99	97	98	100	101	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	-	200	683	758	859	821	939	1,010	1,358	1,500	1,561	1,701	1,808	1,939	1,998	2,163	2,318	2,473	2,704		
	Total Annual Additions	263	327	387	1,959	1,456	1,309	1,729	1,333	1,293	1,720	1,599	1,658	1,799	1,908	2,041	2,104	2,264	2,417	2,573	2,802		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 09

PVRR: $40,204

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	444	536	305	15	-	-	-	-	-	-	-	-	980	1,300
	Total Wind	99	99	-	-	-	-	300	-	444	536	305	15	-	-	-	-	-	-	-	-	1,478	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	43	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	444	968
	DSM, Class 2, WY	-	3.1	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	68	164
	DSM, Class 2 Total	42	50.8	49	52	53	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	529	1,171
	FOT Utah Q3	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	3	1
	FOT Mead Q3	-	-	-	-	-	-	-	-	307	480	512	577	600	600	600	600	600	600	600	600	79	334
	FOT Mona/Nevada Utah Border	-	-	-	-	-	98	198	200	-	192	200	200	200	200	200	200	200	200	200	200	69	134
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	2	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	4	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	370	663
	FOT COB Flat	-	-	220	389	-	-	289	239	239	239	338	338	338	338	-	-	-	-	338	-	162	165
	FOT COB Q3	-	-	-	-	389	389	-	-	-	-	-	-	-	-	338	338	338	338	-	338	78	123
	FOT MidColumbia Q3	-	-	-	326	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	273	336
	FOT West Main Q3	-	-	-	-	29	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	28	39
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	118	123	130	124	124	128	221	407	N/A	172
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	306	287	436	492	474	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	3	110	234	5	309	313	319	321	N/A	202
	Annual Additions, Long Term Resources	256	317	178	998	185	152	415	385	562	645	394	105	93	94	95	96	446	97	98	97		
	Annual Additions, Short Term Resources	-	-	220	716	818	937	938	916	996	1,362	1,499	1,565	1,709	1,820	1,956	2,023	2,307	2,464	2,619	2,789		
	Total Annual Additions	256	317	398	1,713	1,003	1,089	1,353	1,300	1,558	2,007	1,894	1,670	1,801	1,914	2,051	2,118	2,753	2,561	2,718	2,886		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 10

PVRR: $40,319

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	52	248	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	194	106	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	361	151	590	197	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	361	291	750	391	158	248	200	-	-	-	-	-	-	-	-	-	2,398	2,598
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	6	8	4	4	-	-	-	-	-	-	-	-	-	-	44	44
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	16	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	41	49	44	45	45	51	51	50	53	51	55	54	54	56	58	62	59	55	57	56	478	1,043
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	171
	DSM, Class 2 Total	43	54	52	55	56	62	62	61	64	63	66	65	66	68	70	74	72	68	70	68	571	1,257
	FOT Mona Q3	-	-	-	-	-	63	177	200	78	200	200	200	200	200	200	200	200	200	200	200	72	136
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	531	577	587	600	600	600	600	600	600	600	96	343
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	3	1	1	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	495
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	57	122
	DSM, Class 2 Total	35	37	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	378	679
	FOT COB Flat	-	-	213	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	239	288
	FOT MidColumbia Q3	-	-	-	316	371	400	400	400	162	389	400	400	400	400	400	400	400	400	400	400	244	322
	FOT West Main Q3	-	-	-	-	37	50	-	50	50	50	-	14	50	50	50	50	50	50	50	50	24	33
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	121	116	131	122	130	137	148	N/A	125
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	216	332	450	372	526	N/A	237
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	50	177	-	89	109	309	266	N/A	125
	Annual Additions, Long Term Resources	259	321	182	1,002	550	451	911	827	283	362	299	97	98	99	101	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	-	213	705	798	902	867	939	1,010	1,358	1,468	1,529	1,669	1,777	1,908	1,966	2,131	2,287	2,441	2,610		
	Total Annual Additions	259	321	395	1,707	1,348	1,353	1,778	1,766	1,293	1,719	1,767	1,626	1,767	1,876	2,010	2,073	2,233	2,385	2,541	2,709		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 11

PVRR: $40,559

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	14	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	133	-	-	-	-	-	-	-	-	-	-	133	133
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	12	352	617	185	-	-	-	-	-	-	-	-	-	981	1,167
	Wind, WYSW, 35	-	-	64	300	286	224	425	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	64	300	500	650	585	12	652	750	185	-	-	-	-	-	-	-	-	-	3,712	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	-	-	-	-	-	8	19
	CHP - Kern River	-	-	-	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	47	55	49	49	52	53	53	52	53	57	55	56	56	58	59	73	64	62	57	56	520	1,116
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	73	175
	DSM, Class 2 Total	50	61	57	59	63	64	64	63	65	69	67	67	68	70	71	86	77	75	70	68	616	1,335
	FOT Mona Q3	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	20	10
	FOT Mead Q3	-	-	-	-	-	-	-	-	276	87	128	187	40	125	239	424	433	165	-	-	36	105
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	62	38	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	2	100	98	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	-	200	-	100	165	738	98	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	6	6	61	128
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	30	30	30	30	385	689
	FOT COB Flat	-	-	196	-	-	389	289	239	-	-	-	-	-	338	-	-	-	-	-	-	111	73
	FOT COB Q3	-	-	-	389	389	-	-	-	239	239	338	338	338	-	338	338	400	400	400	-	126	207
	FOT MidColumbia Q3	-	-	-	285	273	344	400	400	400	400	400	400	400	400	400	400	400	400	400	118	250	311
	FOT West Main Q3	-	-	-	-	-	-	-	24	-	-	-	-	-	-	-	-	50	50	50	50	2	11
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	288	439	615	637	N/A	250
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	256	480	1,264	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	285	290	293	133	-	-	-	-	N/A	125
	Annual Additions, Long Term Resources	267	329	251	1,512	765	918	900	907	876	1,476	285	99	101	102	104	117	108	106	100	98		
	Annual Additions, Short Term Resources	-	-	196	674	663	733	689	863	915	726	866	925	1,063	1,168	1,298	1,348	1,571	1,721	1,980	2,152		
	Total Annual Additions	267	329	447	2,186	1,427	1,651	1,589	1,770	1,791	2,202	1,151	1,024	1,164	1,270	1,402	1,465	1,679	1,827	2,080	2,250		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 12

PVRR: $50,146

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	108	-	-	-	-	-	-	-	95	97	-	-	-	-	-	-	-	108	300
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	135	65	-	-	-	-	-	-	-	-	-	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	334	300	199	468	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	441	300	338	628	-	-	-	135	161	97	-	-	-	-	-	-	-	1,905	2,297
	Battery Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	15
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	4	-	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	22.6	-	7.3	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	37	10	71	10	25	10	10	-	-	8	-	-	-	-	-	-	-	288	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	47	55.1	49	49	52	53	52	52	53	57	55	60	61	63	65	89	65	68	68	62	520	1,176
	DSM, Class 2, WY	1	3.4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	11	73	176
	DSM, Class 2 Total	50	60.4	57	59	63	64	63	63	64	68	67	72	73	75	77	102	78	81	81	75	612	1,393
	FOT Utah Q3	-	-	-	-	-	50	-	50	-	-	-	50	50	50	50	50	50	50	50	50	10	28
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	515	600	600	600	600	600	600	600	600	600	96	344
	FOT Mona/Nevada Utah Border	-	30	67	200	200	200	141	200	168	157	200	200	200	200	200	200	200	200	200	200	136	168
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	107	166	153	203	148	17	88	118	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	479	401	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	14	86	124	214	225	-	97	240	N/A	125
West																							
	CCCT F 2x1	-	-	-	-	-	-	627	-	-	-	-	-	-	-	-	-	-	-	-	-	627	627
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	385	-	-	790
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	2	-	-	-	-	-	-	-	-	24	25

Case 12

PVRR: $50,146

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	2.9	-	-	-	-	1.2	-	-	-	-	-	-	-	2.9	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	5.8
DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	21	-	3	-	-	-	-	10	-	-	-	-	-	-	-	24	34
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	498
DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
DSM, Class 2 Total	36	37.2	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	382	689
FOT COB Flat	-	-	389	-	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	218	261
FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	39	39
FOT Mid Columbia Flat	-	-	-	-	303	400	202	400	239	297	342	400	400	400	400	400	400	400	400	400	184	289
FOT MidColumbia Q3	-	-	-	398	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	20
FOT West Main Q3	-	-	-	50	50	50	-	50	50	-	50	50	50	50	50	50	50	50	50	50	25	38
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	157	179	161	181	184	289	308	542	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	714	526	675	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	1	132	317	24	409	422	437	258	N/A	250
Annual Additions, Long Term Resources	271	333	193	1,467	1,032	588	1,415	180	126	719	235	270	221	107	109	134	109	517	497	121		
Annual Additions, Short Term Resources	-	30	457	1,037	943	1,089	633	939	1,177	1,173	1,445	1,638	1,916	2,201	2,513	2,737	3,089	3,079	3,094	3,533		
Total Annual Additions	271	363	650	2,504	1,974	1,678	2,048	1,119	1,303	1,892	1,680	1,908	2,138	2,308	2,622	2,872	3,198	3,596	3,591	3,654		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 13

PVRR: $31,076

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	250	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	92	108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	286	24	-	165	-	-	-	-	-	-	-	286	476
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	101	161	224	339	-	-	-	-	-	-	-	-	-	-	824	824
	Wind, WYSW, 35	-	308	42	54	151	394	350	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	499	400	104	151	394	750	161	224	625	24	-	165	-	-	-	-	-	-	-	3,408	3,598
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	55	49	51	52	53	52	52	53	57	55	55	56	58	59	73	64	62	60	60	523	1,126
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	73	173
	DSM, Class 2 Total	50	61	57	62	63	64	63	63	64	68	67	67	68	70	71	85	77	75	73	72	615	1,340
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	296	49	156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	120	100	396	349	356	-	100	-	-	-	-	-	-	-	-	-	-	-	-	1,465	1,465
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	65
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	291	496
	DSM, Class 2, YA	6	7	6	6	6	6	6	7	7	7	7	7	7	7	7	8	7	7	7	7	65	136
	DSM, Class 2 Total	37	39	40	40	40	40	40	41	40	30	31	31	31	30	31	32	31	31	31	31	389	698
	FOT COB Q3	-	-	-	193	400	127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Mid Columbia Flat	-	-	-	110	71	66	60	52	52	80	108	106	-	-	-	-	-	-	-	-	49	35
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	103	98	98	72	74	70	68	65	N/A	81
	Annual Additions, Long Term Resources	267	829	694	1,515	765	911	897	416	347	1,341	122	97	264	100	102	117	108	106	104	103		
	Annual Additions, Short Term Resources	-	-	-	303	471	193	60	52	52	80	108	106	103	98	98	72	74	70	68	65		
	Total Annual Additions	267	829	694	1,818	1,236	1,105	957	469	399	1,421	230	203	367	198	200	189	182	176	172	168		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 14

PVRR: $39,949

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	238	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	101	-	100	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	174	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	55	68	185	191	-	-	-	-	-	-	-	55	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	291	-	-	-	-	-	-	-	-	-	-	291	291
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	267	14	207	-	-	-	-	-	-	-	-	487
	Wind, WYSW, 29	-	-	-	-	-	-	-	351	382	276	-	-	-	-	-	-	-	-	-	-	1,009	1,009
	Wind, WYSW, 35	-	320.5	42	66	193	229	451	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	594	305	128	193	329	750	750	382	622	335	199	398	-	-	-	-	-	-	-	4,153	5,085
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	-	-	-	-	-	8	19
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2.0	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59.0	49	52	53	53	53	52	53	57	55	56	61	63	59	73	65	62	60	60	530	1,145
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	64.7	58	62	64	64	64	63	65	69	67	67	73	75	71	86	77	76	73	73	627	1,366
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	480	480	445	480	178	491	452	480	500	600	96	277
	FOT Mona/Nevada Utah Border	-	-	-	4	52	182	200	200	14	-	-	-	-	44	-	200	-	104	200	200	65	70
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	94	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	5	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	272	13	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	25.0	195	372	307	421	-	-	100	-	-	-	-	-	-	-	-	-	-	-	1,465	1,465
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	3	4	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	3	34	66
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
	DSM, Class 2, YA	6	7	6	6	6	6	6	7	7	7	7	7	7	7	7	8	7	7	7	7	65	136
	DSM, Class 2 Total	37	38.7	40	40	40	41	40	41	41	30	31	31	31	31	31	32	31	31	31	31	391	701
	FOT COB Flat	-	-	-	-	-	-	289	-	-	25	-	179	338	338	338	-	-	-	-	-	31	75
	FOT COB Q3	-	-	122	389	400	389	-	239	239	-	129	-	-	-	-	338	338	338	338	338	178	180
	FOT Mid Columbia Flat	-	-	-	143	113	118	122	301	132	174	210	218	2	13	-	-	63	63	146	154	110	99
	FOT West Main Q3	-	-	-	50	50	-	40	50	-	-	-	-	-	-	-	-	-	-	-	9	19	10
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	9	83	153	-	41	116	117	N/A	65
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	-	-	-	-	-	N/A	57
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	224	210	161	76	181	147	-	-	N/A	125
	Annual Additions, Long Term Resources	271	833	700	1,511	766	913	900	909	609	1,350	436	299	506	108	104	117	574	106	104	104		
	Annual Additions, Short Term Resources	-	-	122	586	615	689	651	790	866	679	819	877	1,009	1,110	1,240	1,290	1,034	1,183	1,335	1,500		
	Total Annual Additions	271	833	823	2,097	1,381	1,602	1,551	1,699	1,475	2,028	1,255	1,176	1,515	1,218	1,344	1,407	1,608	1,290	1,439	1,603		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 15

PVRR: $50,914

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	86	-	-	214	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	213	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	167	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	750	100	-	-	-	-	-	-	-	-	51	900
	Wind, WYSW, 29	-	-	-	-	-	-	15	336	750	200	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	333.4	54	87	214	176	436	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	174	300	176	750	750	750	750	750	100	-	-	-	-	-	-	-	-	4,648	5,497
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	4	-	-	-	-	-	-	-	-	68	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	2.3	-	-	-	4.0	-	-	-	-	-	-	-	-	2.3	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	17	10	10	90	10	10	-	4	-	-	-	-	-	-	-	-	292	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	20	43
	DSM, Class 2, UT	54	64.0	56	57	58	58	60	57	60	61	60	60	62	63	65	89	65	62	60	60	587	1,233
	DSM, Class 2, WY	1	3.9	6	9	9	10	10	9	10	10	10	10	10	11	10	10	10	11	11	10	78	182
	DSM, Class 2 Total	57	69.9	65	68	69	70	71	69	72	73	72	72	74	76	77	102	77	76	73	73	685	1,457
	Solar	-	-	-	-	-	250	250	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	FOT Utah Q3	-	-	-	-	25	50	50	50	-	-	-	50	-	-	-	-	-	-	-	50	17	14
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	585	600	600	600	600	600	480	583	600	600	96	340
	FOT Mona/Nevada Utah Border	-	-	-	200	200	200	200	200	179	160	200	200	200	200	200	200	20	200	200	200	134	158
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	18	-	-	79	-	-	11	289	N/A	49
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	171	N/A	21
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	226	-	274	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20.0	200	326	200	574	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	2	-	-	-	-	-	-	-	-	24	25

Case 15

PVRR: $50,914

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	1.0	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	5.5
DSM, Class 1, WM-Irrigate	-	-	-	-	-	7.4	-	5.1	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	8	7	12	-	-	-	7	-	-	-	-	-	-	-	-	27	34
DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	34	67
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	20	21	21	21	21	21	294	501
DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	7	66	138
DSM, Class 2 Total	37	38.7	41	41	41	41	41	42	41	31	31	31	31	31	31	32	31	31	31	31	394	705
FOT COB Flat	-	-	-	-	-	-	289	-	-	239	-	338	338	338	338	-	-	-	-	-	53	94
FOT COB Q3	-	-	367	389	400	389	-	239	239	-	338	-	-	-	-	338	338	338	338	338	202	202
FOT Mid Columbia Flat	-	-	-	301	400	400	400	400	212	269	314	400	400	400	236	400	400	400	400	400	238	307
FOT West Main Q3	-	-	-	50	50	50	50	50	50	-	-	50	50	50	-	50	-	50	50	50	30	33
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	110	120	165	264	-	47	150	147	N/A	125
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	32	438	999	530	-	-	-	-	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	196	82	-	302	34	8	243	139	N/A	125
Annual Additions, Long Term Resources	281	844	715	1,522	785	1,183	1,170	1,273	884	1,475	855	221	107	109	110	135	2,175	106	104	104		
Annual Additions, Short Term Resources	-	-	367	940	1,075	1,089	989	939	1,160	1,148	1,437	1,638	1,943	2,227	2,538	2,763	1,271	1,626	1,991	2,383		
Total Annual Additions	281	844	1,082	2,462	1,860	2,273	2,160	2,212	2,045	2,624	2,292	1,859	2,051	2,335	2,648	2,898	3,445	1,733	2,095	2,486		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 16

PVRR: $43,523

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	112	88	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	403	-	-	-	-	-	-	-	-	-	-	403	403
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	305	384	208	-	-	-	-	-	-	-	-	-	-	-	897	897
	Wind, WYSW, 35	-	-	104	300	201	638	57	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	104	300	500	750	750	384	208	403	-	-	-	-	-	-	-	-	-	-	3,597	3,597
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	43	49	44	48	49	51	51	50	53	51	55	54	54	58	59	73	65	62	60	60	489	1,088
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	73	173
	DSM, Class 2 Total	46	54	52	59	60	62	62	61	64	62	66	65	66	70	71	85	77	76	73	73	580	1,302
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	30	31	31	31	31	31	31	20	21	20	20	20	20	21	21	21	21	21	291	496
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	381	687
	FOT COB Flat	-	-	-	-	-	118	-	-	-	74	51	-	-	-	-	-	-	171	167	172	19	38
	FOT COB Q3	-	-	-	192	116	7	-	-	-	-	-	-	-	-	-	-	170	-	-	-	32	24
	FOT Mid Columbia Flat	-	-	-	-	88	91	85	80	80	108	137	135	-	-	-	-	-	-	-	-	53	40
	FOT MidColumbia Q3	-	-	-	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	6
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	N/A	1
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	132	128	129	103	105	100	99	87	N/A	110
	Annual Additions, Long Term Resources	262	321	286	1,518	762	910	898	539	332	516	99	98	99	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	-	-	308	204	217	85	80	80	183	188	135	132	128	129	103	275	271	266	267		
	Total Annual Additions	262	321	286	1,826	966	1,127	983	619	412	699	288	233	231	230	231	221	1,259	378	370	371		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 17

PVRR: $51,207

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	14	-	-	286	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	151	-	-	-	-	-	-	-	-	-	-	151	151
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	394	595	59	101	-	-	-	-	-	-	-	-	-	-	1,149	1,149
	Wind, WYSW, 35	-	-	194	286	201	600	20	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	194	300	500	750	750	595	110	500	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	55	49	49	49	51	51	52	53	57	55	56	56	58	59	73	65	62	60	60	508	1,112
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	73	175
	DSM, Class 2 Total	46	61	57	59	60	62	62	63	65	69	67	67	68	70	71	86	77	76	73	73	603	1,332
	FOT Mona Q3	-	-	-	85	119	182	200	200	67	200	200	200	200	200	200	200	200	200	200	200	105	153
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	30	163	-	11	190	83	N/A	62
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	7	-	N/A	3
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	497
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	382	688
	FOT COB Flat	-	-	197	-	-	288	289	239	239	239	338	338	338	338	338	-	-	338	338	338	149	210
	FOT COB Q3	-	-	-	389	389	101	-	-	-	-	-	-	-	-	-	338	338	-	-	-	88	78
	FOT Mid Columbia Flat	-	-	-	-	129	143	161	386	161	203	241	300	331	400	400	400	400	400	400	400	118	243
	FOT MidColumbia Q3	-	-	-	149	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7
	FOT West Main Q3	-	-	-	50	50	50	50	50	-	45	50	50	50	50	50	50	50	50	50	50	29	40
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	107	121	127	107	187	237	236	233	N/A	169
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	486	467	370	677	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	6	116	36	105	212	276	250	N/A	125
	Annual Additions, Long Term Resources	262	328	381	1,519	762	910	898	752	243	620	100	100	101	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	-	197	673	688	764	701	875	947	1,287	1,429	1,487	1,625	1,731	1,861	1,910	2,365	2,515	2,666	2,831		
	Total Annual Additions	262	328	578	2,192	1,450	1,674	1,599	1,628	1,191	1,907	1,529	1,587	1,726	1,833	1,964	2,029	3,349	2,621	2,770	2,934		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 18

PVRR: $49,745

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	52	248	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	100	698	2	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	-	-	263	201	750	86	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	263	500	750	286	400	750	750	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	41	49	44	45	49	51	51	50	53	51	55	54	54	56	59	73	64	62	60	60	482	1,079
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	172
	DSM, Class 2 Total	43	54	52	55	60	62	62	61	64	63	66	65	66	68	71	85	77	75	73	72	576	1,295
	FOT Mona Q3	-	-	-	-	-	-	31	200	-	144	185	200	200	184	200	200	200	200	200	200	37	117
	FOT Mead Q3	-	-	-	-	-	-	-	-	305	480	480	526	480	480	600	480	600	600	600	600	79	312
	FOT Utah Q3	-	-	-	-	-	-	-	14	-	-	-	-	-	-	-	-	-	-	50	50	1	6
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	190	180	N/A	57
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	166	682	N/A	106
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	496
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	57	122
	DSM, Class 2 Total	35	37	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	378	679
	FOT COB Flat	-	-	213	389	-	-	289	239	-	-	338	338	338	338	338	-	338	338	338	338	113	208
	FOT COB Q3	-	-	-	-	345	389	-	-	239	239	-	-	-	-	-	338	-	-	-	-	121	77
	FOT MidColumbia Q3	-	-	-	310	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	271	335
	FOT West Main Q3	-	-	-	-	-	21	30	50	24	47	50	50	50	50	50	50	50	50	50	50	17	34
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	116	122	128	131	122	127	134	147	N/A	128
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	70	172	123	229	515	518	262	111	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	82	173	303	309	107	N/A	125
	Annual Additions, Long Term Resources	259	322	182	1,277	728	945	634	555	881	863	99	97	98	99	102	118	983	106	103	103		
	Annual Additions, Short Term Resources	-	-	213	699	745	810	749	903	969	1,310	1,453	1,514	1,654	1,762	1,892	1,942	2,397	2,547	2,699	2,864		
	Total Annual Additions	259	322	395	1,976	1,472	1,755	1,384	1,459	1,849	2,173	1,552	1,610	1,752	1,861	1,995	2,060	3,381	2,653	2,802	2,967		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 19

PVRR: $50,102

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	16	16
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	201	750	333	-	-	-	-	-	-	-	-	-	-	-	1,284	1,284
	Wind, WYSW, 35	-	-	-	400	201	650	50	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	400	500	650	750	750	385	265	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	48	49	49	51	51	50	53	57	55	56	56	58	59	73	65	62	60	60	500	1,104
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	72	174
	DSM, Class 2 Total	45	54	56	59	60	62	62	61	65	68	67	67	68	70	71	86	77	76	73	73	594	1,322
	FOT Mona Q3	-	-	-	-	-	-	18	200	-	168	200	200	200	200	200	200	200	200	200	200	39	119
	FOT Mead Q3	-	-	-	-	-	-	-	-	305	480	492	551	544	600	585	556	600	600	600	600	78	326
	FOT Utah Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	116	180	N/A	48
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	471	N/A	59
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WM, 35	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	100	-	100	-	-	200	-	-	-	-	-	-	-	-	-	-	-	465	465
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	63
	DSM, Class 2, WM	28	28	30	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	497
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	381	688
	FOT COB Flat	-	-	207	389	-	-	289	239	239	239	338	338	338	338	338	-	-	-	-	-	160	165
	FOT COB Q3	-	-	-	-	389	389	-	-	-	-	-	-	-	-	-	338	338	338	400	400	78	130
	FOT MidColumbia Q3	-	-	-	292	306	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	260	330
	FOT West Main Q3	-	-	-	-	-	5	-	42	-	-	-	-	50	50	50	50	50	50	50	50	5	22
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	94	121	128	130	127	144	131	147	N/A	128
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	7	134	206	362	479	534	279	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	290	294	299	118	N/A	125
	Annual Additions, Long Term Resources	262	322	187	1,519	764	910	898	905	716	384	100	100	101	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	-	207	682	695	794	707	881	944	1,287	1,429	1,488	1,626	1,732	1,862	1,911	2,366	2,516	2,729	2,894		
	Total Annual Additions	262	322	393	2,201	1,459	1,704	1,605	1,787	1,660	1,671	1,529	1,588	1,727	1,834	1,965	2,030	3,350	2,622	2,833	2,998		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 20

PVRR: $50,536

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	-	-	-	-	53	247	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	32	-	245	23	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	51	326	123	-	-	-	-	-	-	-	-	51	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	133	253	-	-	-	-	-	-	-	-	-	-	386	386
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	424	476	-	-	-	-	-	-	-	-	-	900
	Wind, WYSW, 29	-	-	-	-	-	-	368	182	363	-	-	-	-	-	-	-	-	-	-	-	914	914
	Wind, WYSW, 35	-	-	344	224	201	505	26	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	344	456	500	750	418	182	550	750	750	600	-	-	-	-	-	-	-	-	4,148	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	-	-	-	-	-	9	19
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	47	55	49	51	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	56	524	1,123
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	68	620	1,344
	FOT Mona Q3	-	-	-	-	-	-	-	200	-	58	101	159	-	-	-	151	-	-	-	-	26	33
	FOT Mead Q3	-	-	-	-	-	-	-	-	275	480	480	480	-	189	346	480	139	277	-	-	75	157
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	232	268	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	56	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	156	44	-	-	332	568	200	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	6	62	129
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	30	30	387	691
	FOT COB Flat	-	-	184	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	9
	FOT COB Q3	-	-	-	389	400	320	285	239	239	239	338	338	400	400	400	400	400	400	400	400	211	299
	FOT MidColumbia Q3	-	-	-	241	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	264	332
	FOT West Main Q3	-	-	-	-	-	-	-	16	-	50	50	50	-	-	-	50	-	-	-	-	7	11
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	273	181	92	94	-	-	363	998	N/A	250
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	389	257	304	50	-	-	66	934	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	164	289	292	254	-	-	-	-	N/A	125
	Annual Additions, Long Term Resources	267	329	688	1,522	766	913	900	907	882	869	849	699	101	102	104	117	2,584	106	104	98		
	Annual Additions, Short Term Resources	-	-	184	631	800	720	685	855	914	1,228	1,368	1,426	1,626	1,732	1,862	1,912	939	1,088	1,264	2,814		
	Total Annual Additions	267	329	872	2,153	1,566	1,633	1,585	1,762	1,797	2,097	2,218	2,125	1,728	1,834	1,965	2,029	3,522	1,194	1,367	2,912		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 21

PVRR: $40,517

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	251	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	93	107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	151	339	-	-	-	-	-	-	-	-	-	151	489
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	229	200	-	-	-	-	-	-	-	-	-	-	429	429
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	101	750	21	-	-	-	-	-	-	-	-	-	-	-	871	871
	Wind, WYSW, 35	-	307	42	59	361	196	335	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	499	400	108	500	356	436	750	750	350	339	-	-	-	-	-	-	-	-	-	4,248	4,587
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	20	42
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	530	1,134
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	68	67	67	68	70	71	86	77	76	73	73	625	1,353
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	480	480	0	48
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	292	-	94	114	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	113	-	-	-	-	-	-	-	-	-	-	113
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	120	100	392	-	394	314	-	-	400	113	-	-	-	-	-	-	-	-	-	1,765	1,878
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
	DSM, Class 2, YA	6	7	6	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	139
	DSM, Class 2 Total	37	39	40	40	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	392	705
	FOT COB Q3	-	-	-	192	116	126	-	-	400	-	-	-	-	-	-	-	-	-	-	-	84	42
	FOT Mid Columbia Flat	-	-	-	110	82	73	60	54	53	72	97	94	-	-	-	-	-	-	-	-	50	35
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	92	87	87	61	63	58	57	52	N/A	70
	Annual Additions, Long Term Resources	271	833	694	1,516	766	912	898	906	874	867	550	98	100	101	102	117	2,585	107	104	106		
	Annual Additions, Short Term Resources	-	-	-	302	198	200	60	54	453	72	97	94	92	87	87	61	63	58	537	532		
	Total Annual Additions	271	833	694	1,818	964	1,112	958	960	1,327	939	647	192	191	187	189	178	2,647	165	641	638		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 22

PVRR: $49,983

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	-	-	-	1,600
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	238	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	118	82	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	179	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	376	124	-	-	-	-	-	-	-	-	-	376	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	66	200	-	-	-	-	-	-	-	-	-	-	265	265
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	376	524	-	-	-	-	-	-	-	-	-	900
	Wind, WYSW, 29	-	-	-	-	-	-	101	632	303	-	-	-	-	-	-	-	-	-	-	-	1,035	1,035
	Wind, WYSW, 35	-	321	41	90	361	238	249	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	152	500	398	350	750	750	575	501	524	-	-	-	-	-	-	-	-	4,473	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	-	-	-	-	-	-	-	-	-	-	-	5	5
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59	49	52	53	58	60	57	60	61	60	60	61	63	65	73	65	62	60	60	559	1,188
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	177
	DSM, Class 2 Total	53	65	58	63	64	69	71	68	72	73	71	72	74	75	77	86	77	76	73	73	656	1,410
	FOT Mona Q3	-	-	-	16	43	132	193	200	-	-	-	-	-	28	131	192	-	-	-	-	58	47
	FOT Mead Q3	-	-	-	-	-	-	-	-	423	480	480	480	480	480	480	480	53	185	480	480	90	249
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	75	225	-	-	-	-	-	-	-	-	-	75	300
	Wind, YA, 29 PPA	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	248	-	152	100	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	24	176	-	-	-	-	-	-	-	-	-	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	348	-	352	400	-	-	175	249	176	-	-	-	-	-	-	-	-	1,540	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12

Case # 22

PVRR: $49,983

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	21	21	20	21	21	21	21	21	293	499
DSM, Class 2, YA	6	7	6	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	139
DSM, Class 2 Total	37	39	40	40	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	392	705
FOT COB Flat	-	-	-	-	-	-	-	-	-	-	-	-	285	338	338	338	-	-	-	-	-	65
FOT COB Q3	-	-	122	389	389	389	289	239	400	7	110	158	-	-	-	-	-	-	-	-	223	125
FOT Mid Columbia Flat	-	-	-	143	123	128	121	318	134	172	201	205	59	62	80	6	108	123	159	174	114	116
FOT West Main Q3	-	-	-	43	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	29	15
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	-	-	5	7	N/A	10
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	154	157	151	141	123	114	84	75	N/A	125
Annual Additions, Long Term Resources	271	833	695	1,516	767	918	907	913	883	1,479	852	802	105	106	108	117	2,585	107	104	106		
Annual Additions, Short Term Resources	-	-	122	591	605	700	653	807	1,007	658	791	843	978	1,081	1,208	1,258	284	433	763	818		
Total Annual Additions	271	833	817	2,108	1,372	1,618	1,560	1,720	1,890	2,137	1,644	1,645	1,083	1,187	1,316	1,375	2,868	540	867	924		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 23

PVRR: $51,692

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	-	113	-	187	-	-	-	-	-	-	-	-	113	300
	Wind, GO, 29	-	-	44	256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	109	91	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	436	64	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	-	-	-	-	-	88
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	47	750	15	-	-	-	-	-	-	-	-	47	812
	Wind, WYSW, 29	-	-	-	-	-	-	750	50	-	-	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	309	56	244	201	491	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	408	300	500	500	491	750	486	173	750	750	291	-	-	-	-	-	-	-	-	4,457	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	47	55	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	524	1,128
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	62	64	64	64	63	65	68	67	67	68	70	71	86	77	76	73	73	617	1,346
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	480	480	480	480	-	96
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	159	-	64	277	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	-	-	259	-	264	577	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	8	7	7	7	9	63	136
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	31	31	31	30	31	32	31	31	31	32	388	699
	FOT COB Flat	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	1	0
	FOT COB Q3	-	-	-	191	114	124	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43	21
	FOT Mid Columbia Flat	-	-	-	-	86	85	79	67	55	83	112	109	-	-	-	-	-	-	-	-	46	34
	FOT MidColumbia Q3	-	-	-	114	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	6
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	107	102	102	76	78	73	72	68	N/A	85
	Annual Additions, Long Term Resources	267	638	689	1,523	767	913	900	907	876	870	851	390	101	102	103	119	4,184	107	104	105		
	Annual Additions, Short Term Resources	-	-	-	305	201	209	79	67	55	90	112	109	107	102	102	76	558	553	552	548		
	Total Annual Additions	267	638	689	1,828	967	1,122	979	974	931	959	962	500	208	204	206	195	4,743	660	656	653		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 24

PVRR: $60,693

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	135	165	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	206	94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	154	46	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	161	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	424	-	-	-	-	-	-	-	-	-	-	-	-	424	424
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	-	111	-	-	-	-	-	-	-	-	-	111
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	39	750	-	-	-	-	-	-	-	-	-	39	789
	Wind, WYSW, 29	-	-	-	-	-	59	750	67	-	-	-	-	-	-	-	-	-	-	-	-	876	876
	Wind, WYSW, 35	-	327	55	406	201	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	588	300	500	500	370	750	491	289	750	750	111	-	-	-	-	-	-	-	-	4,637	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	46
	DSM, Class 2, UT	47	55	49	52	53	53	53	52	53	57	60	60	61	63	65	73	65	62	60	60	524	1,153
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	177
	DSM, Class 2 Total	51	61	58	63	64	64	64	63	65	69	71	72	74	75	77	86	77	76	73	73	621	1,375
	FOT Mona Q3	-	-	-	59	90	180	200	200	27	200	200	200	200	200	200	109	-	-	-	-	96	103
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	551	600	600	600	600	600	480	480	480	480	480	103	322
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	31	-	10	34	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	280	-	59	161	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	-	-	380	-	259	461	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	33	66
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	499
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	8	7	7	7	9	63	136
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	31	31	31	31	31	32	31	31	31	33	388	701

Case # 24

PVRR: $60,693

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
FOT COB Flat	-	-	128	-	-	-	289	239	239	239	338	338	338	338	-	-	-	-	-	-	114	124
FOT COB Q3	-	-	-	389	389	389	-	-	-	-	-	-	-	-	338	338	-	-	-	-	117	92
FOT Mid Columbia Flat	-	-	-	-	128	137	140	352	136	178	214	223	146	102	66	28	85	202	265	273	107	134
FOT MidColumbia Q3	-	-	-	147	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7
FOT West Main Q3	-	-	-	-	-	-	43	50	-	50	4	50	50	50	50	50	-	-	-	-	14	20
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	5	10	-	24	-	-	-	-	N/A	5
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	125	297	578	-	-	-	-	N/A	125
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	206	205	193	181	163	52	-	-	N/A	125
Annual Additions, Long Term Resources	268	819	689	1,523	767	913	900	908	876	877	854	215	106	107	110	119	4,185	107	104	106		
Annual Additions, Short Term Resources	-	-	128	596	607	706	673	841	883	1,218	1,355	1,411	1,544	1,646	1,771	1,820	728	745	780	835		
Total Annual Additions	268	819	818	2,119	1,374	1,620	1,573	1,749	1,759	2,095	2,210	1,626	1,651	1,753	1,881	1,939	4,913	852	884	941		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 25

PVRR: $58,838

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	251	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	12	-	238	50	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	30	470	-	-	-	-	-	-	-	-	-	30	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	20	53	175	-	-	-	-	-	-	-	-	20	248
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	228	-	-	-	-	-	-	-	-	-	-	228
	Wind, WYSW, 29	-	-	-	-	-	-	701	100	-	-	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	-	399	389	201	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	399	401	500	750	750	600	49	501	750	175	-	-	-	-	-	-	-	-	4,148	5,073
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	43	55	49	51	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	519	1,123
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	46	61	57	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	73	615	1,344
	FOT Mona Q3	-	-	-	-	-	-	-	165	200	200	200	200	200	-	200	82	200	-	200	-	57	92
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	480	480	480	480	480	480	480	480	480	189	96	273
	FOT Utah Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	16	-	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	242	234	N/A	70
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	966	N/A	125
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	51	49	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	51	450	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	1	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	101	99	-	-	-	151	701	249	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	61	129
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	31	31	385	691

Case # 25

PVRR: $58,838

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
FOT COB Flat	-	-	185	389	-	-	-	-	-	-	-	-	-	-	-	-	338	338	338	338	57	96
FOT COB Q3	-	-	-	-	400	400	400	400	400	400	400	400	400	338	400	338	-	-	-	-	240	234
FOT MidColumbia Q3	-	-	-	272	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	267	334
FOT West Main Q3	-	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	25	38
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	86	85	103	79	335	325	321	318	N/A	206
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	10	22	120	389	398	567	459	36	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	278	82	-	103	283	31	223	N/A	125
Annual Additions, Long Term Resources	262	329	689	1,522	767	913	900	908	883	869	849	274	101	102	103	118	984	106	104	104		
Annual Additions, Short Term Resources	-	-	185	661	800	850	850	1,015	1,530	1,530	1,530	1,530	1,626	1,669	1,862	1,849	2,304	2,453	2,604	2,769		
Total Annual Additions	262	329	874	2,184	1,567	1,763	1,750	1,923	2,413	2,400	2,379	1,804	1,726	1,771	1,965	1,967	3,288	2,560	2,708	2,873		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 26

PVRR: $59,660

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	48	252	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	11	-	240	50	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	-	95	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	51	450	-	-	-	-	-	-	-	-	-	51	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	441	-	-	-	-	-	-	-	-	-	-	-	-	441	441
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	116
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	301	484	-	-	-	-	-	-	-	-	-	784
	Wind, WYSW, 29	-	-	-	-	-	-	701	158	-	-	-	-	-	-	-	-	-	-	-	-	859	859
	Wind, WYSW, 35	-	-	359	335	201	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	359	441	500	750	750	600	48	503	750	600	-	-	-	-	-	-	-	-	4,148	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	17	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	47	55	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	523	1,127
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	73	620	1,348
	FOT Mona Q3	-	-	-	-	-	-	-	200	-	51	143	200	-	-	-	124	-	-	-	-	25	36
	FOT Mead Q3	-	-	-	-	-	-	-	-	272	480	480	482	326	357	480	480	480	-	-	-	75	192
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	51	50	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	-	453	47	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	41	59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	141	59	-	-	-	151	702	247	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	62	131
	DSM, Class 2 Total	37	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	31	31	387	693
	FOT COB Flat	-	-	182	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	29
	FOT COB Q3	-	-	-	-	400	400	400	400	400	400	400	400	338	338	237	338	-	-	-	-	240	222
	FOT MidColumbia Q3	-	-	-	254	400	328	400	400	400	400	400	400	400	400	400	400	251	257	268	277	258	302
	FOT West Main Q3	-	-	-	-	-	-	-	9	-	50	-	-	-	-	-	-	-	-	-	-	6	3
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	35	85	92	73	-	-	-	-	N/A	36
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	175	179	265	381	-	-	-	-	N/A	125
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	403	289	292	16	-	-	-	-	N/A	125
	Annual Additions, Long Term Resources	267	330	689	1,523	767	913	900	908	883	869	849	698	101	102	103	118	4,184	106	104	104		
	Annual Additions, Short Term Resources	-	-	182	643	800	728	800	1,009	1,072	1,381	1,423	1,482	1,676	1,664	1,794	1,843	731	268	303	360		
	Total Annual Additions	267	330	870	2,167	1,567	1,641	1,700	1,916	1,956	2,251	2,273	2,180	1,776	1,765	1,897	1,961	4,915	375	407	463		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 27

PVRR: $60,484

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	130	170	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	201	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	171	29	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	48	183	-	-	-	-	-	-	-	-	-	-	-	231	231
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	750	100	-	-	-	-	-	-	-	-	51	900
	Wind, WYSW, 29	-	-	-	-	-	-	750	319	-	-	-	-	-	-	-	-	-	-	-	-	1,069	1,069
	Wind, WYSW, 35	-	323	76	368	201	333	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	422	477	467	500	333	750	367	483	750	750	100	-	-	-	-	-	-	-	-	4,648	5,497
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	1	1	1	1	1	2	2	2	2	2	2	2	2	2	-	-	-	-	-	11	19
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	0	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	47	59	49	52	53	58	60	57	60	61	60	60	62	63	65	73	65	62	57	55	557	1,178
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	10	10	10	10	10	11	10	10	10	11	11	10	76	179
	DSM, Class 2 Total	51	65	58	63	64	69	71	69	73	74	72	72	74	76	77	86	77	75	70	67	655	1,403
	FOT Mona Q3	-	-	-	-	-	-	-	137	-	22	60	112	-	-	36	147	-	200	200	-	16	46
	FOT Mead Q3	-	-	-	-	-	-	-	-	169	480	480	480	480	344	480	480	480	480	480	-	65	242
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	27	31	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	317	-	183	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	77	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	81	-	-	-	-	-	-	-	-	-	81
	Wind, WW, 29 PPA	-	-	-	33	-	100	-	100	67	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	197	23	33	-	417	-	383	267	-	-	81	-	-	-	-	-	-	-	-	1,365	1,446
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	34	65
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	20	21	21	21	21	20	293	500
	DSM, Class 2, YA	6	7	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	6	6	63	130
	DSM, Class 2 Total	37	39	40	40	40	41	41	41	41	31	31	31	31	30	31	31	30	30	30	29	390	695
	FOT COB Flat	-	-	126	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	6
	FOT COB Q3	-	-	-	389	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	279	339
	FOT MidColumbia Q3	-	-	-	204	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	117	260	316
	FOT West Main Q3	-	-	-	-	-	-	-	50	50	50	50	50	50	50	50	50	-	-	-	-	15	23
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	201	178	117	87	-	368	397	653	N/A	250
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	431	-	1,569	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	44	288	291	256	-	121	-	-	N/A	125
	Annual Additions, Long Term Resources	267	834	689	1,523	767	919	908	913	885	882	856	286	107	108	109	117	4,184	106	99	97		
	Annual Additions, Short Term Resources	-	-	126	593	800	800	800	987	1,019	1,352	1,390	1,443	1,575	1,676	1,802	1,852	1,280	2,410	1,911	2,821		
	Total Annual Additions	267	834	816	2,116	1,567	1,719	1,708	1,900	1,904	2,235	2,246	1,728	1,683	1,785	1,911	1,969	5,464	2,516	2,011	2,917		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 28

PVRR: $47,806

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	-	251	50	-	-	-	-	-	-	-	-	-	251	300
	Wind, GO, 29	-	-	249	51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	668	203	429	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	307	45	213	201	535	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	406	493	264	500	535	668	203	429	451	50	-	-	-	-	-	-	-	-	-	4,048	4,098
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	20	42
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	56	58	59	73	59	55	57	55	530	1,113
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	68	67	67	68	70	71	85	72	68	70	68	625	1,331
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	201	100	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	18	82	100	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	136	-	97	-	247	20	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	93	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	213	7	236	-	215	82	547	321	300	-	-	-	-	-	-	-	-	-	-	1,965	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	20	20	21	21	21	293	498
	DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	140
	DSM, Class 2 Total	37	39	41	41	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	393	705
	FOT COB Q3	-	-	-	192	116	400	400	400	400	4	-	-	-	-	-	-	-	400	-	-	191	116
	FOT Mid Columbia Flat	-	-	-	109	81	79	70	53	45	66	94	92	-	-	-	-	-	-	-	-	50	35
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	89	84	85	58	60	55	54	49	N/A	67
	Annual Additions, Long Term Resources	271	833	695	1,516	766	912	898	906	874	867	148	98	100	101	102	117	4,179	99	101	101		
	Annual Additions, Short Term Resources	-	-	-	302	197	479	470	453	445	70	94	92	89	84	85	58	60	455	54	49		
	Total Annual Additions	271	833	695	1,818	963	1,392	1,368	1,359	1,319	937	242	190	188	185	187	175	4,239	555	155	150		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 29

PVRR: $57,635

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	101	200	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	218	82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	-	207	-	-	-	-	-	-	-	-	-	-	207
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	493	700	-	-	-	-	-	-	-	-	-	1,193
	Wind, WYSW, 29	-	-	-	-	-	-	750	223	327	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	322	60	229	201	489	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	421	478	311	500	489	750	223	628	200	701	700	-	-	-	-	-	-	-	-	4,098	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	-	-	-	-	-	10	19
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	8	8	8	8	8	8	8	8	8	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	92	12	-	-	-	-	-	-	-	-	-	-	290	290
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	46
	DSM, Class 2, UT	50	64	56	57	58	58	60	57	60	61	60	60	62	63	65	89	65	68	68	61	583	1,244
	DSM, Class 2, WY	1	4	6	9	9	10	10	9	10	10	10	10	10	11	11	11	10	11	11	10	78	183
	DSM, Class 2 Total	54	70	65	68	70	70	72	69	73	74	72	72	74	76	78	102	78	81	81	74	684	1,474
	FOT Mona Q3	-	-	-	-	-	-	-	26	-	200	200	200	-	-	-	-	-	-	-	-	23	31
	FOT Mead Q3	-	-	-	-	-	-	-	-	-	69	106	160	-	-	-	-	-	-	-	-	7	17
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	50	50	-	-	-	-	-	-	-	-	10	10
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	27	31	-	10	34	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	-	78	22	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	89	-	161	-	250	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	78	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	151	50	-	-	-	-	-	-	-	-	-	151	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	198	22	189	-	261	-	527	122	551	50	-	-	-	-	-	-	-	-	-	1,916	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	1	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	-	1	3	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	22	3	-	-	-	-	-	-	-	-	-	-	26	26

Case # 29

PVRR: $57,635

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	21	21	21	21	21	21	294	502
DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	67	140
DSM, Class 2 Total	37	39	41	41	41	41	41	42	41	31	31	31	31	31	31	32	31	31	31	33	395	709
FOT COB Flat	-	-	-	-	-	-	-	-	-	-	-	-	338	338	338	338	-	-	-	-	-	68
FOT COB Q3	-	-	102	389	389	400	400	400	400	239	338	338	-	-	-	-	-	400	-	-	272	190
FOT Mid Columbia Flat	-	-	-	142	124	211	266	400	400	400	400	400	328	348	358	326	81	101	125	141	194	228
FOT MidColumbia Q3	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	1
FOT West Main Q3	-	-	-	25	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	32	31
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	170	172	181	202	-	-	-	-	N/A	91
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	107	186	287	334	-	-	-	-	N/A	114
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	324	321	315	311	140	127	114	105	N/A	220
Annual Additions, Long Term Resources	272	845	708	1,529	778	925	914	920	995	886	855	805	108	109	111	135	4,652	112	112	107		
Annual Additions, Short Term Resources	-	-	102	556	564	661	716	926	850	1,009	1,144	1,197	1,330	1,431	1,555	1,591	221	638	273	328		
Total Annual Additions	272	845	811	2,085	1,342	1,586	1,630	1,845	1,845	1,895	1,999	2,002	1,438	1,539	1,666	1,726	4,873	750	384	435		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 30

PVRR: $48,541

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	UT IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	-	-	-	466
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	251	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	-	150	50	-	-	-	-	-	-	-	-	-	200
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	-	-	47	453	-	-	-	-	-	-	-	-	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	360	-	-	-	-	-	-	-	-	-	-	360	360
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	-	408	142	350	-	-	-	-	-	-	-	900
	Wind, WYSW, 29	-	-	-	-	-	-	-	400	501	39	-	-	-	-	-	-	-	-	-	-	940	940
	Wind, WYSW, 35	-	-	-	150	300	411	440	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	150	300	750	750	550	550	650	150	506	594	350	-	-	-	-	-	-	3,898	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	47	55	49	49	52	53	53	52	53	57	55	60	61	63	65	89	65	62	68	61	520	1,170
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	59	64	64	64	63	65	69	67	72	74	75	77	102	77	76	81	74	616	1,391
	FOT Mona Q3	-	-	-	90	196	200	200	200	59	200	200	200	200	200	200	200	-	-	-	-	115	117
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	599	480	-	-	-	108	258
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	1	3	-	-	-	-	6	N/A	1
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100
	Wind, MC, 29	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	144	156	-	-	-	-	-	-	-	-	300
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	200	300
	Total Wind	45	20	-	-	200	-	-	200	200	100	600	244	156	-	-	-	-	-	-	-	765	1,765
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	33	66
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	21	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	8	7	7	7	9	63	136
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	41	30	31	31	31	31	31	32	31	31	31	33	387	700
	FOT COB Flat	-	-	197	-	389	389	289	239	239	239	338	338	338	338	338	338	-	-	-	-	198	200
	FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39	19
	FOT Mid Columbia Flat	-	-	-	-	128	152	199	373	144	217	236	277	181	149	138	55	70	70	86	88	121	128
	FOT MidColumbia Q3	-	-	-	152	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	FOT West Main Q3	-	-	-	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	25	13
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	152	149	147	131	119	114	98	91	N/A	125
	Annual Additions, Long Term Resources	267	329	188	1,157	704	954	900	943	883	870	851	855	857	458	110	135	4,651	107	112	107		
	Annual Additions, Short Term Resources	-	-	197	681	764	791	738	863	922	1,256	1,373	1,414	1,471	1,437	1,425	1,322	669	184	183	185		
	Total Annual Additions	267	329	385	1,839	1,467	1,746	1,639	1,805	1,805	2,126	2,224	2,270	2,328	1,895	1,535	1,457	5,319	291	295	292		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 31

PVRR: $47,552

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	215	85	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	227	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	61	-	139	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	33	200	-	-	-	-	-	-	-	-	-	-	232	232
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	750	100	-	-	-	-	-	-	-	-	51	900
	Wind, WYSW, 29	-	-	-	-	-	-	39	396	632	-	-	-	-	-	-	-	-	-	-	-	1,068	1,068
	Wind, WYSW, 35	-	320	53	54	182	280	411	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	419	480	127	182	341	750	750	750	750	750	100	-	-	-	-	-	-	-	-	4,648	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	46
	DSM, Class 2, UT	50	59	56	57	58	58	60	57	60	61	60	60	62	63	65	89	65	62	60	60	577	1,225
	DSM, Class 2, WY	1	4	6	9	9	9	10	9	10	10	10	10	10	11	11	11	10	11	11	10	77	182
	DSM, Class 2 Total	54	65	65	68	69	70	72	69	73	74	72	72	74	76	78	102	78	76	73	72	677	1,452
	FOT Mona Q3	-	-	-	42	35	165	200	200	-	200	200	200	200	200	200	200	200	200	200	-	84	132
	FOT Mead Q3	-	-	-	-	-	-	-	-	451	508	560	600	600	600	600	543	480	480	480	-	96	295
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	-	-	-	-	6	N/A	1
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100
	Wind, MC, 29	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	300
	Wind, YA, 29 PPA	-	-	-	5	95	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	168	123	209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	80	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	200	20	373	318	409	-	-	-	-	-	600	-	-	-	-	-	-	-	-	1,365	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	21	21	21	21	21	21	294	501
	DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	7	67	139
	DSM, Class 2 Total	37	39	41	41	41	41	41	42	41	31	31	31	31	31	31	32	31	31	31	31	395	707
	FOT COB Flat	-	-	115	-	-	-	289	-	-	-	-	-	338	338	338	338	-	-	-	-	40	88
	FOT COB Q3	-	-	-	389	389	389	-	239	239	239	338	338	-	-	-	-	400	400	400	-	189	188
	FOT Mid Columbia Flat	-	-	-	138	111	117	120	273	133	175	211	204	61	49	50	28	56	57	73	120	107	99
	FOT West Main Q3	-	-	-	-	50	-	17	50	-	50	-	6	50	34	-	-	-	-	-	-	17	13
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	N/A	2
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	-	-	N/A	2
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	160	153	154	150	124	118	102	39	N/A	125
	Annual Additions, Long Term Resources	272	835	709	1,516	773	919	909	914	885	882	855	805	108	109	111	136	4,185	107	104	103		
	Annual Additions, Short Term Resources	-	-	115	570	586	671	626	762	824	1,172	1,308	1,348	1,409	1,375	1,362	1,258	1,261	1,256	1,255	178		
	Total Annual Additions	272	835	824	2,086	1,359	1,590	1,535	1,677	1,709	2,055	2,164	2,153	1,517	1,484	1,473	1,394	5,446	1,363	1,359	281		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 33

PVRR: $69,949

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	SCCT Frame ID	-	-	-	-	-	-	-	302	-	-	-	-	-	-	-	-	-	-	-	-	302	302
	SCCT Frame WYNE	-	-	-	-	-	-	-	275	-	-	-	-	-	-	-	-	-	-	-	-	275	275
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	83	-	-	-	-	17	150	50	-	-	-	-	-	-	-	-	-	251	300
	Wind, GO, 29	-	-	172	128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	-	182	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	519	131	750	-	-	-	-	-	-	-	-	1,400
	Wind, WYSW, 29	-	-	-	-	-	-	550	217	533	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	314	124	171	201	491	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	413	478	400	500	491	550	217	750	150	569	131	750	-	-	-	-	-	-	-	4,048	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	8	4	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	9	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	23	16	-	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, WY-Curtail	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	54	10	33	55	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	21	47
	DSM, Class 2, UT	54	64	57	57	62	63	65	61	64	66	68	66	67	69	70	90	78	74	73	63	614	1,331
	DSM, Class 2, WY	2	4	7	9	9	10	10	10	10	10	10	10	11	11	11	11	12	12	12	11	82	194
	DSM, Class 2 Total	58	70	66	68	74	75	78	73	77	79	81	78	80	82	84	104	92	88	88	77	717	1,571
	Solar	-	-	-	-	250	250	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	FOT Mona Q3	-	-	-	-	-	-	84	-	-	-	-	-	-	-	-	-	-	-	-	-	8	4
	FOT Mead Q3	-	-	-	-	-	-	-	-	114	75	254	-	-	-	-	-	-	-	-	-	19	22
	FOT Utah Q3	-	18	-	50	-	-	50	-	50	50	50	49	50	50	50	50	50	50	50	50	22	36
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	220	279	243	259	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	252	144	267	337	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	155	362	452	N/A	125
West																							
	CCCT H 2x1	-	-	-	-	-	-	-	-	-	-	-	523	-	-	-	-	-	-	-	-	-	523
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	8	-	-	92	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, YA, 29 PPA	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	67	-	433	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	86	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	206	22	100	-	259	200	533	-	600	-	-	-	-	-	-	-	-	-	-	1,965	1,965
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	385	-	-	790
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	3	1	-	-	-	-	-	-	-	-	-	-	25	25

Case # 33

PVRR: $69,949

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, WW-Irrigate	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, WM-Irrigate	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, YA-Curtail	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, YA-Irrigate	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1 & 3 Total	-	-	-	20	-	-	8	-	6	-	-	-	-	-	-	-	-	-	-	-	34	34
DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	4	3	4	4	4	4	4	4	34	70
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	21	21	21	21	21	21	21	21	21	21	21	294	504
DSM, Class 2, YA	7	7	7	6	6	7	7	7	7	8	8	8	8	8	8	9	8	8	8	9	68	149
DSM, Class 2 Total	38	39	41	41	41	41	41	42	41	31	32	32	32	32	32	34	32	33	33	34	396	722
FOT COB Flat	-	-	371	-	-	-	-	-	-	-	-	338	338	338	338	338	338	338	338	-	37	154
FOT COB Q3	-	-	-	389	400	400	400	400	400	239	338	-	-	-	-	-	-	-	-	338	263	165
FOT Mid Columbia Flat	-	-	-	400	396	400	400	383	400	400	400	400	400	400	400	400	400	400	400	400	278	339
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	27	218	303	453	367	275	180	178	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	267	489	294	203	253	495	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	272	358	314	164	281	374	133	104	N/A	250
Annual Additions, Long Term Resources	282	845	709	1,573	1,033	1,203	973	1,501	900	1,481	683	765	864	116	118	139	124	526	506	111		
Annual Additions, Short Term Resources	-	18	371	889	846	850	984	833	1,014	814	1,092	837	1,136	1,414	1,720	1,943	2,283	2,267	2,275	2,662		
Total Annual Additions	282	863	1,080	2,462	1,879	2,053	1,957	2,334	1,914	2,295	1,775	1,602	2,000	1,531	1,838	2,082	2,407	2,792	2,781	2,773		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 34

PVRR: $40,564

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	53	247	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	14	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	180	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	80	503	716	-	-	-	-	-	-	-	-	-	584	1,300
	Wind, WYSW, 35	-	-	353	78	327	304	239	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	353	258	500	750	239	-	134	750	716	-	-	-	-	-	-	-	-	-	3,181	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	7	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	17	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	45	51	51	50	52	51	55	54	54	56	58	62	59	55	57	56	480	1,045
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	70	171
	DSM, Class 2 Total	45	54	52	55	56	61	62	61	64	63	66	65	66	68	70	74	72	68	70	68	572	1,259
	FOT Mona Q3	-	-	-	79	158	200	200	200	87	200	200	200	200	200	200	200	200	200	200	200	112	156
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	47	-	-	-	-	5	5
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	94	163	-	11	35	83	N/A	50
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	2	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	20	20
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	495
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	56	122
	DSM, Class 2 Total	36	37	39	39	39	39	39	40	40	30	30	30	30	29	30	31	30	30	30	30	377	678
	FOT COB Flat	-	-	200	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	238	271
	FOT COB Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	-	17
	FOT Mid Columbia Flat	-	-	-	-	130	163	233	400	163	271	306	366	321	400	400	400	400	400	400	400	136	258
	FOT MidColumbia Q3	-	-	-	149	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7
	FOT West Main Q3	-	-	-	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	34	42
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	100	105	107	111	118	129	144	N/A	114
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	195	376	646	780	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	90	97	144	85	261	218	67	39	N/A	125
	Annual Additions, Long Term Resources	262	321	538	1,471	692	914	396	167	258	863	815	97	98	100	102	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	-	200	653	728	803	772	939	1,019	1,360	1,493	1,554	1,694	1,801	1,932	1,990	2,155	2,311	2,465	2,634		
	Total Annual Additions	262	321	738	2,124	1,420	1,717	1,168	1,106	1,277	2,223	2,309	1,651	1,792	1,901	2,034	2,097	2,257	2,409	2,565	2,732		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 35

PVRR: $39,853

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	101	-	200	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	226	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	170	-	-	-	-	-	-	-	-	-	-	170	170
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	548	326	256	-	-	-	-	-	-	-	-	-	-	1,130	1,130
	Wind, WYSW, 35	-	321	53	51	167	257	451	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	420	479	125	167	358	750	748	326	426	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	55	56	58	59	73	59	55	57	55	530	1,113
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	69	67	67	68	70	71	85	72	68	70	67	627	1,331
	FOT Mona Q3	-	-	-	53	134	200	200	200	78	-	-	-	-	132	200	200	200	200	200	-	87	100
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	333	343	396	480	480	508	531	600	600	480	-	81	262
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	35	83	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	75	133	292	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	79	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	199	21	375	333	392	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	20	293	498
	DSM, Class 2, YA	6	7	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	6	63	130
	DSM, Class 2 Total	37	39	40	40	40	41	40	40	40	30	30	30	31	30	31	31	30	30	30	30	389	691
	FOT COB Flat	-	-	122	-	-	389	289	239	239	239	338	-	338	338	338	338	338	338	-	-	152	194
	FOT COB Q3	-	-	-	389	389	-	-	-	-	-	-	338	-	-	-	-	-	-	338	400	78	93
	FOT Mid Columbia Flat	-	-	-	136	109	118	151	362	136	178	214	223	8	20	46	26	105	109	115	117	119	109
	FOT West Main Q3	-	-	-	-	-	19	50	50	-	-	-	-	47	-	12	50	50	50	50	50	12	21
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	5	9	-	7	54	168	285	472	N/A	125
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	232	359	1,000	N/A	203
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	218	208	203	202	168	-	-	-	N/A	125
	Annual Additions, Long Term Resources	271	834	701	1,510	731	912	898	902	450	1,149	97	97	99	100	101	116	102	98	100	97		
	Annual Additions, Short Term Resources	-	-	122	578	632	726	690	851	933	750	895	956	1,096	1,203	1,335	1,386	1,551	1,707	1,861	2,122		
	Total Annual Additions	271	834	823	2,088	1,362	1,638	1,587	1,754	1,383	1,900	992	1,053	1,194	1,303	1,436	1,502	1,653	1,805	1,961	2,219		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 36

PVRR: $51,242

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	-	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	251	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	76	-	-	-	-	-	-	-	-	-	-	76	76
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	201	650	373	-	-	-	-	-	-	-	-	-	-	-	1,224	1,224
	Wind, WYSW, 35	-	-	-	418	201	632	50	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	418	500	632	750	650	423	327	-	-	-	-	-	-	-	-	-	-	3,898	3,898
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	8	8	8	8	4	8	8	8	4	4	-	-	-	-	-	-	-	-	64	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	7
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	2
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	10	16	10	-	78	-	-	-	-	-	-	-	-	212	290
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	45
	DSM, Class 2, UT	47	55	49	50	52	53	53	52	53	57	60	60	56	58	59	73	65	62	60	60	521	1,134
	DSM, Class 2, WY	1	3	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	74	176
	DSM, Class 2 Total	50	61	57	60	64	64	64	63	65	69	71	72	68	70	71	86	77	76	73	73	617	1,354
	FOT Mona Q3	-	-	-	-	130	200	-	200	-	143	200	200	200	200	200	200	200	200	200	200	67	134
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	600	600	480	600	600	600	600	600	600	600	96	342
	FOT Utah Q3	-	-	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	28	32	-	11	63	83	N/A	29
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 35	-	-	-	82	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	82	-	118	-	100	200	-	-	-	-	-	-	-	-	-	-	-	565	565
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	3	3	3	3	1	3	3	3	2	2	-	-	-	-	-	-	-	-	22	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	26
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	64
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	498
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	61	130
	DSM, Class 2 Total	36	38	40	40	40	41	40	40	40	30	30	30	31	30	31	31	31	31	31	31	385	691

Case # 36

PVRR: $51,242

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
FOT COB Flat	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	400	-	-	-	-	120	180
FOT COB Q3	-	-	192	389	389	389	289	-	-	-	-	-	-	-	-	-	338	338	338	338	165	150
FOT Mid Columbia Flat	-	-	-	-	-	-	363	400	400	400	400	400	400	400	400	400	400	-	-	-	156	218
FOT MidColumbia Q3	-	-	-	226	133	151	-	-	-	-	-	-	-	-	-	-	-	203	268	329	51	66
FOT West Main Q3	-	-	-	50	50	50	50	50	-	-	-	50	50	50	50	50	50	50	50	50	25	35
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	94	98	172	106	278	396	360	362	N/A	233
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	40	440	222	147	279	367	504	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	214	282	372	132	209	294	276	222	N/A	250
Annual Additions, Long Term Resources	266	328	194	1,526	738	919	900	913	760	451	109	1,089	101	102	103	118	108	106	104	104		
Annual Additions, Short Term Resources	-	-	192	665	703	790	702	1,050	1,280	1,423	1,600	1,700	1,838	2,088	2,661	2,142	2,221	2,371	2,522	2,687		
Total Annual Additions	266	328	386	2,191	1,440	1,709	1,602	1,963	2,040	1,874	1,709	2,789	1,939	2,189	2,764	2,260	2,329	2,477	2,626	2,790		

* For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.

Case # 37

PVRR: $48,949

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	-	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	-	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	238	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	123	77	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	179	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	101	627	373	200	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Wind, WYSW, 35	-	321	42	91	361	238	249	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	153	500	398	349	750	750	200	-	-	-	-	-	-	-	-	-	-	4,097	4,097
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Kern River	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	10	10	17	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	56	58	59	73	65	62	60	60	530	1,134
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	69	67	67	68	70	71	86	77	76	73	73	628	1,356
	FOT Mona Q3	-	-	-	16	75	169	200	200	-	200	200	-	-	-	-	-	-	-	-	-	86	53
	FOT Mead Q3	-	-	-	-	-	-	-	-	479	594	600	-	-	-	-	-	-	-	480	480	107	132
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	82	N/A	25
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	-	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 24	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 29	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 24 PPA	-	-	-	-	-	-	-	-	-	288	12	-	-	-	-	-	-	-	-	-	288	300
	Wind, YA, 29 PPA	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	247	-	152	101	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 24 PPA	-	-	-	-	-	-	-	-	-	163	-	-	-	-	-	-	-	-	-	-	163	163
	Wind, WW, 29 PPA	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	347	-	352	401	-	-	551	12	-	-	-	-	-	-	-	-	-	1,916	1,928
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	3	4	3	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
	DSM, Class 2, YA	6	7	6	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	66	139
	DSM, Class 2 Total	37	39	40	40	41	41	41	41	41	30	31	31	31	31	31	32	31	31	31	33	392	705
	FOT COB Q3	-	-	122	389	389	389	289	239	400	239	338	-	-	-	-	-	-	-	-	-	246	140
	FOT Mid Columbia Flat	-	-	-	143	123	128	158	367	134	162	201	206	60	63	81	76	109	124	165	182	122	124
	FOT West Main Q3	-	-	-	44	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	34	20
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	154	157	151	141	123	114	84	75	N/A	125
	Annual Additions, Long Term Resources	271	833	694	1,516	731	913	898	906	874	874	110	4,174	100	101	102	117	109	107	104	106		
	Annual Additions, Short Term Resources	-	-	122	592	637	736	697	856	1,064	1,245	1,388	206	214	236	260	249	232	249	764	819		
	Total Annual Additions	271	833	817	2,108	1,369	1,649	1,595	1,762	1,938	2,119	1,499	4,380	314	337	362	367	341	356	868	925		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 38

PVRR: $41,974

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	48	171	-	-	-	-	-	-	-	-	-	-	219	219
	Wind, GO, 29	-	-	-	-	-	-	-	190	110	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	208	-	-	-	-	579	513	-	-	-	-	-	-	-	-	-	787	1,300
	Total Wind	99	99	-	-	208	-	300	190	157	750	513	-	-	-	-	-	-	-	-	-	1,803	2,316
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	53	10	10	-	-	-	-	-	-	-	-	-	-	249	249
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	43	49	49	48	49	51	51	50	53	51	55	54	54	56	58	62	59	62	60	60	493	1,073
	DSM, Class 2, WY	1	3	6	8	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	73	173
	DSM, Class 2 Total	46	54	57	59	60	62	62	61	64	63	67	65	66	68	70	74	72	75	73	72	589	1,290
	FOT Mona Q3	-	-	-	-	-	34	102	200	-	176	200	200	200	200	200	200	200	200	200	200	51	126
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	480	496	557	580	600	600	600	518	600	600	600	96	336
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	23	34	38	-	17	42	89	N/A	30
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	1	1	1	1	1	-	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	20	20
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	62
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	291	496
	DSM, Class 2, YA	5	6	6	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	58	123
	DSM, Class 2 Total	36	37	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	379	680
	FOT COB Flat	-	-	193	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	237	287
	FOT MidColumbia Q3	-	-	-	288	326	400	400	400	241	400	400	400	400	400	400	400	400	400	400	400	245	323
	FOT West Main Q3	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	30	40
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	116	121	128	131	122	121	151	147	N/A	130
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	224	518	303	359	479	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	60	56	-	-	266	308	310	N/A	125
	Annual Additions, Long Term Resources	267	327	191	1,011	407	166	453	414	282	863	612	97	98	100	101	107	102	106	103	103		
	Annual Additions, Short Term Resources	-	-	193	678	765	873	841	939	1,010	1,346	1,483	1,544	1,684	1,791	1,922	1,981	2,145	2,296	2,447	2,613		
	Total Annual Additions	267	327	385	1,689	1,172	1,039	1,294	1,353	1,292	2,209	2,095	1,641	1,782	1,891	2,024	2,087	2,247	2,401	2,551	2,715		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 39
PVRR: $34,791

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	48	252	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	298	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	182	-	-	-	-	-	-	-	-	18	-	-	-	-	-	-	182	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55	-	55
	Wind, WYSW, 35	-	178	224	16	178	114	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	277	224	315	362	253	750	-	48	252	-	-	-	18	-	-	-	-	-	55	2,580	2,653
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	2	-	6
	CHP - Kern River	-	-	6	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	8	4	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	93	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	23	45
	DSM, Class 2, UT	50	59	49	52	53	53	53	52	53	57	55	56	61	63	65	89	66	68	68	62	530	1,182
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	11	11	11	11	75	178
	DSM, Class 2 Total	53	65	58	62	64	64	64	63	65	69	67	67	73	75	77	102	79	82	81	75	627	1,405
	FOT Mona Q3	-	-	-	-	-	-	-	-	77	-	-	-	-	-	-	-	-	-	-	-	8	4
	FOT Utah Q3	-	-	-	-	-	-	-	50	50	-	-	43	-	-	-	-	-	-	-	-	10	7
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	16	28	32	-	11	35	194	N/A	39
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	N/A	14
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	76	85	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	120	276	185	138	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	865	865
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	1
	Distributed Standby Generation	3	3	3	3	3	3	3	3	3	1	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 2, WA	3	4	4	3	3	4	4	4	4	3	3	3	3	3	3	3	3	3	3	4	34	67
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	500
	DSM, Class 2, YA	6	7	7	6	6	7	7	7	7	7	7	7	7	7	7	8	7	7	7	9	67	140
	DSM, Class 2 Total	37	39	41	41	41	41	41	41	41	30	31	31	31	31	31	32	31	32	31	33	393	707
	FOT COB Flat	-	-	156	-	389	389	289	239	239	226	338	338	338	338	338	338	338	-	-	-	193	215
	FOT COB Q3	-	-	-	196	-	-	-	-	-	-	-	-	-	-	-	-	-	338	400	338	20	64
	FOT MidColumbia Q3	-	-	-	400	228	323	379	400	400	400	400	400	400	400	400	400	400	400	400	400	253	327
	FOT West Main Q3	-	-	-	-	-	-	-	50	50	-	32	50	-	33	50	50	50	50	50	50	10	26
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94	163	295	197	256	209	N/A	152
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	132	257	365	247	N/A	125
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	228	279	282	247	173	278	229	284	N/A	250
	Annual Additions, Long Term Resources	276	617	700	1,516	736	527	903	270	177	970	98	98	105	124	108	134	111	115	115	166		
	Annual Additions, Short Term Resources	-	-	156	596	617	713	668	739	817	626	770	830	965	1,066	1,192	1,229	1,387	1,530	1,735	1,831		
	Total Annual Additions	276	617	856	2,112	1,353	1,240	1,572	1,009	994	1,596	868	928	1,070	1,189	1,300	1,363	1,498	1,645	1,850	1,997		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 40

PVRR: $25,139

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	51	249	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	193	107	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	341	750	209	-	-	-	-	-	-	-	-	341	1,300
	Total Wind	99	99	-	-	-	-	-	193	298	750	750	209	-	-	-	-	-	-	-	-	1,439	2,398
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	-	13
	CHP - Kern River	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	8	4	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	92	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	45	46	46	45	52	51	55	53	54	56	58	62	59	62	60	60	465	1,044
	DSM, Class 2, WY	1	3	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	70	170
	DSM, Class 2 Total	45	54	52	55	56	57	57	56	64	62	66	65	66	68	70	74	72	75	73	72	557	1,257
	FOT Mona Q3	-	-	-	93	200	200	200	200	-	200	200	200	200	200	200	200	200	200	200	200	109	155
	FOT Mead Q3	-	-	-	-	-	-	-	-	553	600	600	600	600	600	600	600	600	600	600	600	115	358
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	49	50	50	50	50	50	50	50	50	50	10	30
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	148	145	148	-	189	190	180	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	44	158	191	-	204	214	189	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	26	89	86	-	104	279	415	N/A	125
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	100
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	65	165
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	-	2
	Distributed Standby Generation	3	3	3	3	3	3	3	3	3	1	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	0	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	0	-	-	-	-	25	26
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	60
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	495
	DSM, Class 2, YA	5	6	5	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	53	115
	DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	29	29	29	30	29	30	30	30	30	30	30	373	670
	FOT COB Flat	-	-	199	340	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	27
	FOT COB Q3	-	-	-	49	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	183	260
	FOT MidColumbia Q3	-	-	-	155	145	259	339	400	160	207	240	298	77	198	170	132	156	400	400	400	167	207
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	116	122	107	131	123	130	123	148	N/A	125
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	143	-	-	40	817	-	-	-	N/A	125
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	-	306	277	314	N/A	125
	Annual Additions, Long Term Resources	266	325	186	1,006	192	158	145	452	424	859	845	302	107	97	102	107	714	373	206	105		
	Annual Additions, Short Term Resources	-	-	199	688	784	898	879	939	1,003	1,347	1,476	1,535	1,677	1,776	1,907	1,965	2,333	2,571	2,720	2,883		
	Total Annual Additions	266	325	385	1,694	977	1,057	1,023	1,391	1,427	2,206	2,321	1,838	1,785	1,873	2,009	2,072	3,048	2,944	2,926	2,988		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 41

PVRR: $41,542

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	134	134
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	307	166	238	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	307	300	377	750	-	-	-	-	-	-	-	-	-	-	-	-	-	1,932	1,932
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	3.8	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	34	13	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	43	49.0	44	45	49	51	51	50	53	51	55	54	54	56	58	62	59	55	57	56	484	1,049
	DSM, Class 2, WY	1	3.4	6	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	71	172
	DSM, Class 2 Total	46	54.2	52	55	59	61	61	61	63	62	66	65	66	68	70	74	72	68	70	68	575	1,261
	FOT Utah Q3	-	-	-	-	-	4	50	50	-	-	-	21	-	-	-	-	-	-	-	-	10	6
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	584	584	584	584	584	584	584	584	584	584	584	106	345
	FOT Mona/Nevada Utah Border	-	91	56	200	200	200	200	200	78	200	200	200	200	200	200	200	200	200	200	200	142	171
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	64	139	134	169	16	-	-	-	N/A	65
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	128	-	-	-	-	N/A	16
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	8.9	3.4	-	-	-	-	-	-	-	-	-	-	-	-	12.3	12.3
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	14	3	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	290	496
	DSM, Class 2, YA	5	6	6	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	57	123
	DSM, Class 2 Total	36	37.2	39	39	39	40	40	40	40	30	30	30	30	29	30	31	30	30	30	30	379	680
	FOT COB Flat	-	-	383	-	383	383	283	233	233	233	329	329	329	329	329	329	329	329	329	-	213	254
	FOT COB Q3	-	-	-	383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	38	39
	FOT Mid Columbia Flat	-	-	-	-	304	400	400	400	177	320	360	400	389	400	400	322	400	400	400	400	200	294
	FOT MidColumbia Q3	-	-	-	298	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	15
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	99	105	175	110	117	153	218	N/A	134
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	193	427	465	862	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	20	150	-	294	224	303	10	N/A	125
	Annual Additions, Long Term Resources	267	326	187	1,323	770	548	916	425	124	113	99	97	98	99	101	107	102	98	100	98		
	Annual Additions, Short Term Resources	-	91	440	931	937	1,037	983	933	1,018	1,387	1,523	1,584	1,712	1,821	1,952	2,010	2,175	2,331	2,485	2,725		
	Total Annual Additions	267	417	627	2,255	1,707	1,585	1,900	1,358	1,142	1,500	1,622	1,681	1,809	1,920	2,054	2,117	2,277	2,429	2,585	2,823		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 42

PVRR: $51,420

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	209	-	-	91	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	106	94	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	61	-	-	-	-	-	-	-	-	-	-	61	61
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	544	454	50	190	-	-	-	-	-	-	-	-	-	-	1,239	1,239
	Wind, WYSW, 35	-	-	344	91	201	644	20	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	344	300	500	750	750	454	50	252	-	-	-	-	-	-	-	-	-	-	3,598	3,598
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	43	55.1	49	49	49	51	51	52	53	57	55	56	56	58	59	73	65	62	60	60	508	1,112
	DSM, Class 2, WY	1	3.4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	73	175
	DSM, Class 2 Total	46	60.4	57	59	60	62	62	63	64	68	67	67	68	70	71	86	77	76	73	73	601	1,329
	FOT Utah Q3	-	-	-	-	-	-	35	35	-	-	-	-	-	-	-	-	-	-	-	-	7	3
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	584	584	584	584	584	584	584	584	584	584	584	106	345
	FOT Mona/Nevada Utah Border	-	91	54	200	200	200	200	200	107	200	200	200	200	200	200	200	200	200	200	200	145	173
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	18	-	-	138	126	N/A	38
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	N/A	27
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	5	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
	DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	291	497
	DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	59	128
	DSM, Class 2 Total	36	37.2	40	40	39	40	40	40	40	30	30	30	31	30	31	31	31	31	31	31	382	688
	FOT COB Flat	-	-	383	-	-	288	283	233	233	233	329	329	329	329	329	-	-	329	329	329	165	214
	FOT COB Q3	-	-	-	383	383	95	-	-	-	-	-	-	-	-	-	329	329	-	-	-	86	76
	FOT Mid Columbia Flat	-	-	-	-	299	384	400	400	181	295	334	393	400	400	400	400	400	400	400	400	196	294
	FOT MidColumbia Q3	-	-	-	280	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28	14
	FOT West Main Q3	-	-	-	50	50	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	30	40
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	80	121	127	139	228	264	364	364	N/A	211
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	519	375	655	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	38	105	208	247	172	218	60	172	N/A	153
	Annual Additions, Long Term Resources	262	327	531	1,519	762	910	898	872	176	371	100	100	101	102	103	118	984	106	104	104		
	Annual Additions, Short Term Resources	-	91	437	913	932	1,017	968	918	1,002	1,362	1,497	1,556	1,682	1,789	1,919	1,968	2,415	2,565	2,715	2,880		
	Total Annual Additions	262	419	968	2,432	1,694	1,927	1,865	1,790	1,177	1,733	1,597	1,656	1,783	1,891	2,022	2,086	3,399	2,671	2,820	2,984		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 43

PVRR: $60,905

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,200	-	-	-	-	3,200
	Wind, GO, 24	-	-	-	-	-	-	-	97	181	22	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	217	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	81	-	119	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, UT, 29	-	173	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WYAE, 29	-	-	-	-	-	-	-	418	-	-	-	-	-	-	-	-	-	-	-	-	418	418
	Wind, WYNE, 24	-	-	-	-	-	-	-	-	-	-	9	100	-	-	-	-	-	-	-	-	-	109
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	51	741	-	-	-	-	-	-	-	-	-	51	791
	Wind, WYSW, 29	-	-	-	-	-	78	750	54	-	-	-	-	-	-	-	-	-	-	-	-	882	882
	Wind, WYSW, 35	-	327	55	417	201	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	599	300	500	500	377	750	650	181	692	750	100	-	-	-	-	-	-	-	-	4,648	5,498
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	93	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	3	3	3	2	2	2	2	2	2	2	2	2	24	48
	DSM, Class 2, UT	50	59	49	52	53	58	60	57	53	57	60	60	61	63	65	73	65	62	60	60	547	1,176
	DSM, Class 2, WY	1	4	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	177
	DSM, Class 2 Total	53	65	58	63	64	69	71	69	65	69	72	72	74	75	77	86	77	76	73	73	646	1,401
	FOT Mona Q3	-	50	-	200	200	200	200	200	129	200	200	200	200	200	200	161	-	-	-	-	138	127
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	584	584	584	584	584	584	480	480	480	480	480	106	319
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	34	46	49	-	28	52	100	N/A	39
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, MC, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	42	-	-	100	58	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WM, 29	-	-	-	-	-	231	-	-	269	-	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	45	20	200	-	-	373	-	100	569	58	-	-	-	-	-	-	-	-	-	-	1,365	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	-	-	-	-	-	22	22

Case # 43

PVRR: $60,905

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	4	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	3	4	33	66
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	293	499
DSM, Class 2, YA	6	7	6	6	6	6	6	7	6	7	7	7	7	7	7	8	7	7	7	9	64	138
DSM, Class 2 Total	37	39	40	40	40	41	40	42	40	30	31	31	31	31	31	32	31	31	31	33	390	703
FOT COB Flat	-	-	352	-	-	-	283	233	233	233	329	329	329	329	-	-	-	-	-	-	133	132
FOT COB Q3	-	-	-	383	383	383	-	-	-	-	-	-	-	-	329	329	-	-	-	-	115	90
FOT Mid Columbia Flat	-	-	-	-	240	299	359	400	150	243	291	358	273	236	174	51	95	211	275	283	169	197
FOT MidColumbia Q3	-	-	-	197	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	10
FOT West Main Q3	-	-	-	50	19	50	50	50	-	50	50	50	50	50	50	50	-	-	-	-	27	28
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	1	9	-	11	-	-	-	-	N/A	3
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	99	295	606	-	-	-	-	N/A	125
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	206	205	193	181	163	53	-	-	N/A	125
Annual Additions, Long Term Resources	277	840	695	1,529	772	924	913	1,024	877	870	854	204	106	107	110	119	4,185	107	104	106		
Annual Additions, Short Term Resources	-	50	352	830	842	932	892	933	992	1,311	1,454	1,521	1,642	1,745	1,870	1,919	738	773	807	863		
Total Annual Additions	277	890	1,047	2,359	1,614	1,856	1,805	1,957	1,868	2,181	2,308	1,725	1,749	1,853	1,980	2,038	4,923	880	912	968		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 44

PVRR: $21,249

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	54	246	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	195	105	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	-	-	-	200
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Wind, WYAE, 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	141	132	-	273
	Wind, Project I	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	67	54	-	200
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	-	-	470	112	119	175	424	-	-	-	-	-	1,300
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	343	504	454	-	-	-	-	-	-	-	-	-	846	1,300
	Total Wind	99	99	-	-	-	-	-	335	661	750	454	670	112	119	175	424	100	180	208	186	1,944	4,571
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	-	-	-	2	2	2	2	2	2	2	2	-	5	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	30	30
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	39	39
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	92	10	10	-	-	-	-	-	-	-	-	-	-	288	288
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	42
	DSM, Class 2, UT	40	46	42	42	43	45	46	45	45	46	46	46	49	50	51	52	50	53	54	52	441	945
	DSM, Class 2, WY	-	3	5	8	8	8	8	9	9	9	9	9	9	9	9	10	10	10	10	10	66	161
	DSM, Class 2 Total	42	50	49	52	53	56	56	56	56	57	56	57	60	61	63	64	63	66	66	64	528	1,147
	FOT Mona Q3	-	-	-	152	200	200	200	200	81	-	-	-	31	118	200	200	200	200	200	200	103	119
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	378	386	376	480	480	480	578	600	600	600	600	86	302
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	5	3
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	17	29	33	-	12	36	84	N/A	26
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	35
	Wind, MC, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	100
	Wind, MC, 35	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	100	76	-	-	-	-	200
	Wind, WM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	474	-	-	-	-	500
	Wind, WM, 35	-	-	-	-	-	-	-	-	-	-	20	80	-	-	-	-	-	-	-	-	-	100
	Wind, WW, 29 PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	100	-	-	-	-	300
	Total Wind	45	20	-	-	-	-	-	-	-	-	120	80	-	-	124	326	650	-	-	-	65	1,365
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	-	-	-	-	-	-	-	-	-	1	1	1	2	4
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	26	26

Case # 44

PVRR: $21,249

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
DSM, Class 2, WM	28	28	30	30	30	30	31	31	30	20	20	20	20	20	20	20	20	20	20	20	289	491
DSM, Class 2, YA	5	6	5	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	54	115
DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	28	28	28	29	29	29	30	29	30	30	30	372	664
FOT COB Flat	-	-	206	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	238	288
FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	161	203	235	245	6	194	53	243	324	400	400	400	76	163
FOT MidColumbia Q3	-	-	-	155	186	300	347	-	-	-	-	-	-	-	-	-	-	-	-	-	99	49
FOT West Main Q3	-	-	-	-	50	50	50	50	50	-	-	-	-	-	28	-	50	50	50	50	25	24
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	N/A	9
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	247	66	215	-	-	54	185	234	N/A	125
Annual Additions, Long Term Resources	263	322	183	1,003	156	158	181	596	774	1,454	658	872	203	212	393	846	879	277	305	281		
Annual Additions, Short Term Resources	-	-	206	696	825	939	886	939	1,011	820	959	958	1,101	1,213	1,342	1,392	1,511	1,653	1,808	1,980		
Total Annual Additions	263	322	388	1,700	981	1,097	1,068	1,536	1,786	2,274	1,617	1,829	1,304	1,425	1,735	2,238	2,390	1,931	2,114	2,261		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 45

PVRR: $20,967

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero ID	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	397	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	598	598
	Total Wind	99	99	397	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,095	1,095
	CHP - Biomass	1	1	2	2	2	2	2	2	2	2	1	1	-	-	-	-	-	-	-	-	19	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	-	-	-	-	8	21
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1 & 3 Total	25	50	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	16	37
	DSM, Class 2, UT	37	41	42	42	43	44	43	41	46	47	47	48	49	51	52	52	50	53	54	52	427	935
	DSM, Class 2, WY	-	3	5	7	8	8	8	8	9	9	9	9	9	9	10	10	10	10	10	10	65	161
	DSM, Class 2 Total	38	45	48	51	53	54	53	51	57	58	58	59	60	62	64	64	63	66	66	64	508	1,133
	FOT Mona Q3	-	-	-	165	200	200	200	200	75	-	-	-	72	178	200	200	200	200	200	200	104	125
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	405	413	467	480	480	549	600	600	600	600	600	88	314
	FOT Utah Q3	-	-	-	-	-	-	33	35	-	-	-	-	-	-	-	-	-	-	-	-	7	3
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25	-	-	-	50
	CHP - Biomass	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	10	12
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	1	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	29	58
	DSM, Class 2, WM	28	28	30	30	30	30	30	30	30	20	20	20	20	20	20	20	20	20	20	20	288	491
	DSM, Class 2, YA	4	6	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6	6	52	113
	DSM, Class 2 Total	34	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	369	662
	Micro Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.27	-	0
	FOT COB Flat	-	-	223	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	240	289
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	171	213	250	259	-	-	-	-	-	45	184	168	78	85
	FOT MidColumbia Q3	-	-	-	156	204	325	400	-	-	-	-	-	-	-	-	-	-	-	-	-	108	54
	FOT West Main Q3	-	-	-	-	50	50	50	50	50	-	-	-	50	50	50	50	50	50	50	50	25	33
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	96	96	91	133	112	118	124	150	N/A	115
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	159	287	433	595	N/A	188
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	172	178	197	141	178	134	-	-	N/A	125
	Annual Additions, Long Term Resources	251	310	574	1,497	150	149	112	414	116	707	91	92	93	94	131	96	117	121	96	94		
	Annual Additions, Short Term Resources	-	-	223	710	843	964	973	924	1,016	857	1,000	1,064	1,208	1,320	1,424	1,489	1,636	1,772	1,929	2,101		
	Total Annual Additions	251	310	798	2,206	993	1,114	1,085	1,338	1,132	1,565	1,091	1,157	1,301	1,414	1,555	1,585	1,754	1,892	2,025	2,195		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 46

PVRR: $21,532

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600
	IC Aero UT	-	-	-	-	174	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	174	174
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, GO, 29	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	300
	Wind, WYNE, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	444	45	-	-	-	-	-	489
	Total Wind	99	99	-	-	-	140	160	100	-	-	300	-	-	-	444	45	-	-	-	-	598	1,386
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	10	10	10	17	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	3	2	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	26	47
	DSM, Class 2, UT	40	46	42	42	43	45	46	45	46	47	47	48	49	51	52	52	50	53	54	52	443	952
	DSM, Class 2, WY	-	3	5	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	66	162
	DSM, Class 2 Total	43	51	49	53	54	56	57	56	58	59	58	59	60	62	64	64	63	66	66	64	535	1,161
	FOT Mona Q3	-	-	-	151	144	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	130	165
	FOT Mead Q3	-	-	-	-	-	-	-	-	372	600	217	288	373	440	543	600	600	600	600	600	97	292
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	-	-	-	-	-	-	-	-	-	-	10	5
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	38	49	71	-	33	57	104	N/A	44
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, YA, 29 PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, WW, 29 PPA	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	-	1	-	1	1	1	1	1	1	-	-	-	2	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	30	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	371	665
	FOT COB Flat	-	-	197	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	237	287
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	155	228	234	243	-	-	-	-	-	79	176	164	78	84
	FOT MidColumbia Q3	-	-	-	148	129	143	232	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT West Main Q3	-	-	-	-	-	39	50	50	50	50	-	-	50	50	50	50	50	50	50	50	24	32
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	68	69	82	120	84	91	116	138	N/A	96
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	345	467	582	N/A	203
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	184	190	189	138	189	110	-	-	N/A	125
	Annual Additions, Long Term Resources	263	322	383	1,004	329	298	282	249	117	109	989	91	93	94	539	140	92	95	96	94		
	Annual Additions, Short Term Resources	-	-	197	688	663	771	771	939	1,016	1,367	988	1,069	1,213	1,324	1,451	1,516	1,688	1,846	2,004	2,176		
	Total Annual Additions	263	322	581	1,691	991	1,069	1,053	1,188	1,133	1,476	1,977	1,159	1,305	1,419	1,990	1,657	1,781	1,941	2,099	2,270		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 47

PVRR: $20,863

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600
	IC Aero UT	-	-	-	-	174	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	174	174
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, GO, 24	-	-	-	-	-	-	-	-	52	171	-	-	-	-	-	-	-	-	-	-	223	223
	Wind, GO, 29	-	-	-	-	-	-	-	194	106	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	24	23	29	394	53	-	-	-	-	-	522
	Total Wind	99	99	-	-	-	-	-	333	158	331	-	24	23	29	394	53	-	-	-	-	1,020	1,542
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	Distributed Standby Generation	8	8	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	1	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 & 3 Total	25	50	40	30	11	10	10	16	10	10	-	-	-	-	-	-	-	-	-	-	212	212
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	43
	DSM, Class 2, UT	40	46	42	42	43	45	46	45	46	47	47	48	49	51	52	52	50	53	54	52	443	952
	DSM, Class 2, WY	-	3	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	66	163
	DSM, Class 2 Total	42	50	49	52	53	56	56	56	57	59	58	59	60	62	64	64	63	66	66	64	532	1,157
	FOT Mona Q3	-	-	-	152	144	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	130	165
	FOT Mead Q3	-	-	-	-	-	-	-	-	366	600	211	266	351	432	536	600	600	600	600	600	97	288
	FOT Utah Q3	-	-	-	-	-	-	-	50	-	50	-	-	-	-	-	-	-	-	-	-	10	5
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	23	35	49	-	18	42	90	N/A	32
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	-	1	1	1	-	1	-	1	1	1	1	1	1	-	-	-	2	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	30	30	31	31	30	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	371	665
	FOT COB Flat	-	-	205	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	238	288
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	400	161	228	240	249	-	-	-	-	-	-	162	159	79	80
	FOT MidColumbia Q3	-	-	-	155	136	150	245	-	-	-	-	-	-	-	-	-	-	-	-	-	69	34
	FOT West Main Q3	-	-	-	-	-	44	50	50	50	50	-	-	50	50	50	50	50	50	50	50	24	32
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	96	96	91	132	111	118	124	149	N/A	115
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	338	460	575	N/A	197
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	162	169	187	132	168	169	13	-	N/A	125
	Annual Additions, Long Term Resources	263	322	183	1,003	329	158	122	490	275	440	688	115	115	123	489	148	92	95	96	94		
	Annual Additions, Short Term Resources	-	-	205	696	670	784	784	939	1,016	1,367	988	1,053	1,197	1,308	1,435	1,501	1,673	1,831	1,988	2,160		
	Total Annual Additions	263	322	389	1,699	999	942	906	1,429	1,291	1,807	1,677	1,168	1,312	1,430	1,924	1,649	1,765	1,926	2,084	2,254		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case # 48

PVRR: $41,268

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	2012 RFP Lake Side	-	-	-	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	607	607
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 24	-	-	-	-	-	-	-	-	25	275	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, GO, 29	-	-	-	-	-	-	-	171	129	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	281	300	129	590	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	281	300	268	750	171	154	275	-	-	-	-	-	-	-	-	-	-	2,398	2,398
	CHP - Biomass	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	9	21
	CHP - Kern River	-	-	-	6	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 3, GO-CPP-CI	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, GO-CPP-RES	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, GO-DemandB	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Irrigate	-	-	-	-	0	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, GO-RTP-CI	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, GO-TOU-RES	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, UT-CPP-CI	-	-	-	-	2	42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	44
	DSM, Class 3, UT-DemandB	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 3, UT-RTP-CI	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 3, WY-CPP-CI	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	16
	DSM, Class 3, WY-DemandB	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 3, WY-RTP-CI	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1 & 3 Total	39	50	40	30	13	86	10	26	10	10	-	-	-	-	-	-	-	-	-	-	314	314
	DSM, Class 2, GO	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	44
	DSM, Class 2, UT	43	49	44	45	45	46	51	50	52	51	55	54	54	56	58	62	59	55	57	56	475	1,040
	DSM, Class 2, WY	8	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	85	185
	DSM, Class 2 Total	53	59	55	55	56	57	62	61	64	63	66	65	66	68	70	74	72	68	70	68	582	1,269
	FOT Mona Q3	-	-	-	94	200	200	200	200	52	200	200	200	200	200	200	200	200	200	200	200	115	157
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	600	600	600	600	600	600	600	600	600	600	600	108	354
	FOT Utah Q3	-	-	-	-	-	-	-	21	-	-	-	-	-	-	50	50	-	-	-	-	2	6
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	153	148	145	163	144	9	33	81	N/A	110
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	67	79	152	298	-	-	-	-	N/A	75
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 3, WW-DemandB	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, WW-RTP-CI	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 3, WM-RTP-CI	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, WM-DemandB	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 3, YA-DemandB	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, YA-RTP-CI	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1 & 3 Total	2	-	-	-	2	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12

Case # 48

PVRR: $41,268

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	61
DSM, Class 2, WM	14	28	30	30	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	276	481
DSM, Class 2, YA	5	6	6	5	5	6	6	5	6	6	6	6	6	6	7	7	7	7	7	7	56	121
DSM, Class 2 Total	21	37	39	39	39	39	39	39	40	30	30	30	30	29	30	31	30	30	30	30	362	663
FOT COB Flat	-	-	200	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	237	271
FOT COB Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	-	17
FOT Mid Columbia Flat	-	-	-	-	127	160	226	400	160	234	277	337	-	8	149	140	400	400	400	214	131	182
FOT MidColumbia Q3	-	-	-	153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	100	172	121	111	110	112	136	N/A	120
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	-	108	272	616	986	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	161	248	28	-	174	302	86	-	N/A	125
Annual Additions, Long Term Resources	270	326	184	1,288	692	499	897	349	284	388	99	97	98	100	102	107	102	98	100	98		
Annual Additions, Short Term Resources	-	-	200	687	767	799	766	910	981	1,324	1,464	1,525	1,664	1,771	1,902	1,960	2,125	2,281	2,435	2,604		
Total Annual Additions	270	326	384	1,975	1,459	1,299	1,662	1,259	1,265	1,712	1,563	1,622	1,762	1,871	2,004	2,067	2,227	2,379	2,535	2,702		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

B-Series Portfolio Summary Tables

Case 02b

PVRR: $22,040

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600	600
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	550	750	-	-	-	-	-	-	1,300
	Total Wind	99	99	-	-	-	-	140	-	-	-	160	-	-	550	750	-	-	-	-	-	338	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	11	21
	CHP - Kern River	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.8	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	10.8	27.9	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	55	54	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	49.0	46	48	49	51	51	47	46	48	47	48	49	51	52	52	50	55	57	55	477	992
	DSM, Class 2, WY	1	3.4	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	70	167
	DSM, Class 2 Total	46	54.2	53	58	59	61	61	57	57	59	58	59	60	62	64	64	63	67	69	67	565	1,198
	FOT Utah Q3	-	-	-	29	50	50	50	50	-	-	-	-	-	-	50	-	-	-	-	-	23	14
	FOT Mead Q3	-	-	-	-	-	-	-	-	542	480	480	498	600	600	600	600	600	600	600	600	102	340
	FOT Mona/Nevada Utah Border	75	50	150	350	413	200	200	200	200	104	151	200	-	-	-	-	-	-	-	-	194	115
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	198	-	-	-	247	-	N/A	56
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	4	-	N/A	2
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	IC Aero	-	-	-	-	-	287	-	-	-	-	-	-	-	-	-	-	-	-	-	-	287	287
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	-	-	-	-	-	1	1	-	-	-	-	-	5	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	14	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 02b

PVRR: $22,040

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
DSM, Class 2, YA	5	6	6	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	55	116
DSM, Class 2 Total	36	37.2	39	39	39	39	40	39	38	29	29	29	30	29	29	30	29	30	30	30	375	668
FOT COB Flat	-	-	43	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	222	280
FOT Mid Columbia Flat	-	-	-	-	-	-	176	-	-	-	-	-	-	-	-	10	17	191	176	187	18	38
FOT MidColumbia Q3	-	-	-	392	400	400	224	400	-	-	-	-	-	-	-	-	-	-	-	-	182	91
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	95	120	126	136	116	173	230	530	N/A	191
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	249	314	-	286	394	348	213	196	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	10	175	200	187	158	156	283	N/A	146
Annual Additions, Long Term Resources	268	328	189	404	198	528	350	416	115	707	248	89	92	644	845	95	92	97	98	97		
Annual Additions, Short Term Resources	75	50	193	1,210	1,302	1,089	989	939	1,032	874	1,019	1,085	1,332	1,432	1,552	1,619	1,701	1,858	2,013	2,183		
Total Annual Additions	343	378	382	1,614	1,500	1,618	1,339	1,356	1,146	1,581	1,267	1,175	1,424	2,076	2,397	1,714	1,793	1,955	2,112	2,280		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05b

PVRR: $41,265

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	451	750	-	100	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	-	-	750	750	-	100	-	-	-	-	-	-	-	-	-	-	1,798	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	2.0	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	24.7	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.5	0.3	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	78	24	17	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	48.7	44	48	49	53	52	52	47	48	47	48	49	51	52	62	59	55	57	55	485	1,019
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	71	167
	DSM, Class 2 Total	45	53.4	52	58	59	64	63	63	58	59	58	59	60	62	64	74	71	67	69	67	574	1,225
	Fuel Cell	-	-	-	-	-	-	30	10	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	23	50	50	50	50	-	12	26	50	50	50	50	50	-	-	50	18	24	29
	FOT Mead Q3	-	-	-	-	-	-	-	-	540	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	350	415	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	204	122
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	204	200	198	219	-	-	128	52	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	370	268	267	95	-	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	143	223	223	412	-	-	-	-	N/A	125
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	SCCT Aero	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	130	130
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	5	9	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 05b

PVRR: $41,265

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	60
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
DSM, Class 2, YA	5	6	6	5	6	6	6	6	5	6	6	6	6	6	6	6	6	6	6	6	56	117
DSM, Class 2 Total	35	37.2	39	39	39	40	40	40	39	29	29	29	30	29	29	30	29	30	30	30	377	671
Fuel Cell	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Flat	-	-	45	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	183	243
FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	-	205	264	262	-	-	60	32	60	89	161	241	21	69
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	-	97	72	116	-	-	-	-	31	178	110	6	210	131
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	108	100	120	131	136	344	469	519	N/A	241
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47	658	447	290	558	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	0	148	207	199	375	358	364	348	N/A	250
Annual Additions, Long Term Resources	267	327	188	404	199	528	954	1,148	118	208	88	89	92	93	94	105	100	97	98	97		
Annual Additions, Short Term Resources	75	50	195	1,212	1,304	1,089	989	939	1,029	1,404	1,549	1,616	1,863	1,976	2,112	2,171	2,247	2,404	2,559	2,729		
Total Annual Additions	342	377	383	1,616	1,502	1,618	1,944	2,087	1,147	1,612	1,638	1,705	1,954	2,069	2,207	2,276	2,347	2,501	2,658	2,826		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05b_CCCT

PVRR: $41,325

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	CCCT F 2x1	-	-	-	-	-	536	-	-	-	-	-	-	-	-	-	-	-	-	-	-	536	536
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	750	550	-	-	-	-	-	-	-	-	-	750	1,300
	Total Wind	99	99	-	-	-	-	300	-	-	750	550	-	-	-	-	-	-	-	-	-	1,248	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	4	3.8	8	8	8	6	8	8	4	4	-	-	-	-	-	-	-	-	-	-	59	59
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	447	971
	DSM, Class 2, WY	-	3.1	6	8	8	8	9	9	9	9	9	9	9	9	10	10	10	10	10	10	68	165
	DSM, Class 2 Total	42	50.8	49	52	55	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	532	1,173
	FOT Utah Q3	-	-	-	48	50	-	27	50	-	-	-	1	50	50	50	50	-	-	50	-	17	21
	FOT Mead Q3	-	-	-	-	-	-	-	-	540	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	350	444	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	207	123
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	204	173	198	219	-	-	206	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	183	274	252	290	-	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	92	96	95	98	-	-	194	-	N/A	72
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	25	-	-	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	3	3	3	1	3	3	1	1	-	-	-	-	-	-	-	-	-	-	19	19
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	493
	DSM, Class 2, YA	5	6	5	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	372	665
	FOT COB Flat	-	-	65	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	185	244
	FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	-	206	244	263	22	65	80	92	87	157	246	204	21	83
	FOT MidColumbia Q3	-	-	-	400	400	331	400	400	-	95	92	137	-	-	-	14	311	243	154	196	203	159
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	101	145	154	145	141	400	411	N/A	201
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	651	57	667	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	182	199	273	245	166	299	318	316	N/A	250
	Annual Additions, Long Term Resources	258	317	183	396	193	691	421	390	118	858	639	91	93	94	94	95	471	97	123	97		
	Annual Additions, Short Term Resources	75	50	215	1,237	1,333	971	966	939	1,030	1,390	1,523	1,588	1,834	1,946	2,083	2,150	2,322	2,479	2,612	2,782		
	Total Annual Additions	333	367	398	1,634	1,526	1,662	1,387	1,329	1,147	2,249	2,162	1,679	1,927	2,040	2,177	2,245	2,793	2,576	2,735	2,879		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 05b_WC_CCCT

PVRR: $41,271

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	CCCT F 2x1	-	-	-	-	-	570	-	-	-	-	-	-	-	-	-	-	-	-	-	-	570	570
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	750	550	-	-	-	-	-	-	-	-	-	750	1,300
	Total Wind	99	99	-	-	-	-	300	-	-	750	550	-	-	-	-	-	-	-	-	-	1,248	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	-	-	-	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	10	21
	Distributed Standby Generation	4	3.8	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	38	38
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	207	207
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	17	38
	DSM, Class 2, UT	40	46.1	42	42	45	45	46	45	47	48	47	48	49	51	52	52	59	55	57	55	447	971
	DSM, Class 2, WY	-	3.1	6	8	8	8	8	9	9	9	9	9	9	9	10	10	10	10	10	10	68	164
	DSM, Class 2 Total	42	50.8	49	52	55	55	56	56	58	59	58	59	60	62	64	64	71	67	69	67	532	1,173
	FOT Utah Q3	-	-	-	50	50	-	17	45	-	-	-	-	50	50	50	50	-	-	50	-	16	21
	FOT Mead Q3	-	-	-	-	-	-	-	-	536	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	357	458	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	209	124
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	176	187	198	219	-	-	220	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	235	282	207	252	-	-	24	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	31	69	96	98	-	-	120	-	N/A	52
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	25	-	-	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	4	6
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, WM	28	28	30	30	30	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	289	492
	DSM, Class 2, YA	5	6	5	5	5	5	6	5	5	6	6	6	6	6	6	6	6	6	6	6	53	114
	DSM, Class 2 Total	35	36.5	39	39	38	39	39	39	39	29	29	29	30	29	29	30	29	30	30	30	372	665
	FOT COB Flat	-	-	69	389	-	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	186	245
	FOT COB Q3	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338	39	36
	FOT Mid Columbia Flat	-	-	-	-	-	-	-	-	-	207	244	263	51	70	88	98	88	146	246	205	21	85
	FOT MidColumbia Q3	-	-	-	400	400	317	400	400	-	90	87	133	-	-	37	104	312	254	154	195	201	164
	FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	117	101	149	140	137	145	400	371	N/A	195
	Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	569	646	88	698	N/A	250
	Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	182	195	266	197	225	297	318	321	N/A	250
	Annual Additions, Long Term Resources	257	317	178	391	188	723	416	385	118	858	639	91	93	94	94	95	471	97	123	97		
	Annual Additions, Short Term Resources	75	50	219	1,247	1,347	956	957	935	1,025	1,386	1,518	1,584	1,830	1,942	2,078	2,145	2,318	2,474	2,607	2,777		
	Total Annual Additions	332	367	397	1,638	1,535	1,679	1,372	1,319	1,143	2,244	2,157	1,674	1,922	2,035	2,173	2,240	2,789	2,571	2,731	2,874		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 08b

PVRR: $41,922

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	23	177	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	305	277	134	584	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	305	300	750	744	-	-	-	-	-	-	-	-	-	-	-	-	-	2,298	2,298
	CHP - Biomass	2	2.0	2	2	1	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	6	4	4	-	-	-	-	-	-	-	-	-	-	66	66
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.4	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	100	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	58.9	49	51	53	56	54	50	53	51	55	54	54	56	58	62	59	55	57	56	523	1,088
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	50	64.5	57	62	64	67	65	61	64	62	66	65	66	68	70	74	72	68	70	68	617	1,303
	Fuel Cell	-	-	-	-	-	5	35	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	10	50	50	50	50	-	-	-	10	50	50	50	50	50	-	50	-	21	26
	FOT Mead Q3	-	-	-	-	-	-	-	-	535	600	600	600	600	600	600	600	600	600	600	600	114	357
	FOT Mona/Nevada Utah Border	75	50	150	350	295	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	192	116
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	93	106	216	228	221	-	136	-	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	192	193	321	244	50	-	-	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	179	292	79	130	215	-	104	-	N/A	125
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22
	DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 08b

PVRR: $41,922

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	292	497
DSM, Class 2, YA	6	6	6	6	6	6	6	5	6	6	6	6	6	6	7	7	7	7	7	7	60	126
DSM, Class 2 Total	37	38.1	40	40	40	41	40	39	40	30	30	30	30	29	30	31	30	30	30	30	385	685
Fuel Cell	-	-	-	-	-	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
FOT COB Flat	-	-	27	-	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	-	181	242
FOT COB Q3	-	-	-	389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	39	39
FOT Mid Columbia Flat	-	-	-	-	400	400	351	180	-	260	348	400	36	10	83	70	251	372	285	279	159	186
FOT MidColumbia Q3	-	-	-	384	-	-	49	220	-	49	0	-	-	-	-	-	-	-	-	-	70	35
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	94	100	116	212	187	341	363	373	N/A	223
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	103	668	330	889	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	208	211	227	207	147	-	267	163	N/A	179
Annual Additions, Long Term Resources	274	339	194	726	773	1,055	966	417	125	113	98	96	97	99	101	107	102	98	100	98		
Annual Additions, Short Term Resources	75	50	177	1,183	1,184	1,089	989	939	1,024	1,398	1,536	1,598	1,840	1,948	2,080	2,138	2,213	2,368	2,523	2,754		
Total Annual Additions	349	389	371	1,909	1,957	2,144	1,955	1,356	1,149	1,511	1,634	1,694	1,937	2,047	2,181	2,244	2,314	2,467	2,623	2,853		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 09b

PVRR: $40,967

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Project I	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	100	451	750	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	-	100	750	750	-	-	-	-	-	-	-	-	-	-	-	-	1,798	1,798
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	2.0	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	24.5	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	78	25	17	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	18	39
	DSM, Class 2, UT	43	48.7	44	48	49	51	52	52	47	48	47	48	49	51	52	62	59	55	57	55	483	1,016
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	71	167
	DSM, Class 2 Total	45	53.3	52	58	59	61	63	63	58	59	58	59	60	62	64	74	71	67	69	67	572	1,223
	Fuel Cell	-	-	-	-	-	-	35	5	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	23	50	50	50	50	-	-	-	31	-	-	-	-	50	-	50	50	22	20
	FOT Mead Q3	-	-	-	-	-	-	-	-	340	517	564	600	600	600	600	600	600	600	600	600	86	341
	FOT Mona/Nevada Utah Border	75	50	150	350	415	200	200	200	-	200	200	200	-	-	-	-	-	-	-	-	184	112
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95	-	215	237	N/A	68
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	163	118	N/A	35
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	SCCT Aero	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	130	130
	Geothermal	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	-	1.3	-	-	-	-	-	-	-	-	-	-	-	-	1.3	1.3
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	0.1	1.1	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	6	8	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 09b

PVRR: $40,967

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	60
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	21	290	494
DSM, Class 2, YA	5	6	6	5	5	6	6	6	5	6	6	6	6	6	6	6	6	6	6	6	56	117
DSM, Class 2 Total	35	37.2	39	39	39	40	40	40	39	29	29	29	30	29	29	30	29	30	30	30	377	671
Fuel Cell	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Flat	-	-	45	389	-	-	289	239	239	239	338	338	338	338	-	-	-	-	338	-	144	156
FOT COB Q3	-	-	-	-	389	389	-	-	-	-	-	-	-	-	338	338	338	338	-	338	78	123
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	280	340
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	180	129	134	214	208	338	395	402	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	267	319	544	210	396	41	224	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	298	194	274	27	300	285	310	312	N/A	250
Annual Additions, Long Term Resources	267	327	188	404	198	619	966	1,142	118	108	88	89	92	93	94	105	100	97	98	97		
Annual Additions, Short Term Resources	75	50	195	1,212	1,304	1,089	989	939	1,029	1,406	1,552	1,618	1,865	1,978	2,114	2,173	2,249	2,406	2,561	2,731		
Total Annual Additions	342	377	383	1,616	1,502	1,709	1,956	2,081	1,147	1,515	1,640	1,708	1,957	2,071	2,209	2,278	2,349	2,503	2,660	2,828		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 10b

PVRR: $40,904

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	269	31	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Project I	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	389
	Wind, WYSW, 35	-	-	-	-	500	41	719	40	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	-	500	650	750	200	-	-	389	-	-	-	-	-	-	-	-	-	2,298	2,687
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	-	64	64
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.5	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	100	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	55.2	49	51	53	58	53	50	53	51	55	54	54	56	58	62	59	55	57	56	520	1,084
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	50	60.7	57	62	63	69	64	61	64	62	66	65	66	68	70	74	72	68	70	68	613	1,300
	Fuel Cell	-	-	-	-	5	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	4	50	50	50	50	-	-	-	5	50	50	50	50	50	-	50	-	20	25
	FOT Mead Q3	-	-	-	-	-	-	-	-	480	594	600	600	600	600	600	600	600	600	600	600	107	354
	FOT Mona/Nevada Utah Border	75	50	150	350	373	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	200	120
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	91	88	87	108	104	-	136	-	N/A	77
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	150	182	257	57	19	-	336	-	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	37	82	167	34	77	-	327	-	N/A	90
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22
	DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34

Case 10b

PVRR: $40,904

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	292	497
DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	61	126
DSM, Class 2 Total	36	38.1	40	40	40	41	40	40	40	30	30	30	30	29	30	31	30	30	30	30	385	685
Fuel Cell	-	-	-	-	5	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
FOT COB Flat	-	-	30	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	221	279
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	55	315	343	400	400	400	400	400	400	400	400	400	237	316
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	120	127	129	121	126	135	148	N/A	128
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	241	621	-	848	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	5	33	-	78	207	228	146	303	N/A	125
Annual Additions, Long Term Resources	272	335	194	409	725	1,127	965	715	125	113	487	96	97	99	101	107	102	98	100	98		
Annual Additions, Short Term Resources	75	50	180	1,194	1,262	1,089	989	939	1,024	1,398	1,531	1,592	1,835	1,943	2,074	2,132	2,207	2,363	2,517	2,686		
Total Annual Additions	347	385	374	1,602	1,988	2,217	1,955	1,655	1,149	1,511	2,018	1,688	1,932	2,042	2,176	2,239	2,309	2,461	2,617	2,785		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 17b

PVRR: $51,819

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	139	-	161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	-	125	-	-	-	-	-	-	-	-	-	-	125	125
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	701	308	42	125	-	-	-	-	-	-	-	-	-	-	1,175	1,175
	Wind, WYSW, 35	-	-	362	99	201	589	50	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	362	438	500	750	750	308	42	250	-	-	-	-	-	-	-	-	-	-	3,598	3,598
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	-	64	64
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	-	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	2.5	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	10	97	14	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	42
	DSM, Class 2, UT	50	58.9	49	52	58	58	60	52	53	57	55	56	56	58	59	73	65	62	60	60	547	1,151
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	10	9	10	10	10	10	10	11	11	10	75	176
	DSM, Class 2 Total	53	64.5	58	62	69	69	71	63	65	68	67	67	68	70	71	86	77	76	73	73	641	1,369
	Fuel Cell	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	-	50	50	50	45	-	-	-	-	50	50	50	50	50	50	50	50	20	30
	FOT Mead Q3	-	-	-	-	-	-	-	-	529	600	600	600	600	600	600	600	600	600	600	600	113	356
	FOT Mona/Nevada Utah Border	75	50	150	350	240	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	187	113
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	91	88	87	122	30	23	285	275	N/A	125
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	96	194	241	163	-	-	138	167	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	61	61	88	130	-	-	313	347	N/A	125
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	38	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 29	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, WM, 35	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	138	62	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	765	765
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22

Case 17b

PVRR: $51,819

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	27	7	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34
DSM, Class 2, WA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	33	64
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	21	20	21	20	21	21	21	21	21	292	499
DSM, Class 2, YA	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	62	131
DSM, Class 2 Total	37	38.2	40	40	40	41	41	40	40	30	30	30	31	30	31	31	31	31	31	31	387	694
Fuel Cell	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Flat	-	-	14	-	-	288	289	239	239	239	338	338	338	338	338	-	-	338	338	338	131	200
FOT COB Q3	-	-	-	389	389	101	-	-	-	-	-	-	-	-	-	338	338	-	-	-	88	78
FOT Mid Columbia Flat	-	-	-	-	400	400	184	159	-	231	334	322	224	119	272	338	400	400	341	343	137	223
FOT MidColumbia Q3	-	-	-	337	-	-	216	241	-	63	-	71	-	-	-	-	-	-	-	-	86	46
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	236	163	163	178	235	300	586	N/A	247
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	711	750	357	182	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	197	191	169	152	116	176	-	-	N/A	125
Annual Additions, Long Term Resources	276	339	695	921	777	1,038	974	726	168	869	99	99	101	102	103	118	984	106	104	104		
Annual Additions, Short Term Resources	75	50	164	1,127	1,130	1,089	989	935	1,019	1,384	1,521	1,581	1,821	1,927	2,057	2,106	2,471	2,621	2,772	2,937		
Total Annual Additions	351	389	859	2,048	1,907	2,127	1,963	1,660	1,186	2,253	1,620	1,680	1,921	2,029	2,160	2,225	3,455	2,727	2,876	3,040		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 18b

PVRR: $50,597

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	CCS Hunter3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	346
	IC Aero	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	6	86	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	173	173
	Blundell 3	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, GO, 29	-	-	-	-	-	199	101	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, UT, 29	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, WYAE, 29	-	-	-	-	-	-	-	-	154	346	-	-	-	-	-	-	-	-	-	-	500	500
	Wind, Project I	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 29	-	-	-	-	-	-	186	606	8	-	-	-	-	-	-	-	-	-	-	-	800	800
	Wind, WYSW, 35	-	-	-	486	201	351	263	-	-	-	-	-	-	-	-	-	-	-	-	-	1,300	1,300
	Total Wind	99	99	-	486	500	750	550	606	162	346	-	-	-	-	-	-	-	-	-	-	3,598	3,598
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	CHP - Kern River	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Distributed Standby Generation	8	7.5	8	8	8	8	8	4	4	4	-	-	-	-	-	-	-	-	-	-	64	64
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.6	4.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	38.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	12	100	10	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	1.9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	41
	DSM, Class 2, UT	47	55.3	49	52	53	58	53	50	53	51	55	54	56	58	59	73	64	62	60	60	521	1,122
	DSM, Class 2, WY	1	3.7	6	9	9	9	9	9	9	9	9	9	10	10	10	10	10	11	11	10	74	174
	DSM, Class 2 Total	50	60.9	57	62	64	69	64	61	64	62	66	65	68	70	71	85	77	75	73	73	614	1,337
	Fuel Cell	-	-	-	-	5	5	30	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
	FOT Utah Q3	-	-	-	-	50	50	50	43	-	-	-	-	-	-	-	-	50	50	50	50	19	20
	FOT Mead Q3	-	-	-	-	-	-	-	-	326	495	535	596	600	600	600	600	600	600	600	600	82	338
	FOT Mona/Nevada Utah Border	75	50	150	344	290	200	200	200	-	200	200	200	-	-	-	-	-	-	-	-	171	105
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	-	104	133	136	126	N/A	71
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	148	305	376	N/A	125
	Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139	333	416	N/A	111
West																							
	CCS Bridger1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	CCS Bridger2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-	265
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Geothermal	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, MC, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Wind, WM, 35	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	45	20.0	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	265	265
	Utility Biomass	-	-	-	-	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	22	22

Case 18b

PVRR: $50,597

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 1, WW-Curtail	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
DSM, Class 1, WW-DLC-RES	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
DSM, Class 1, WW-Sch-TES	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DSM, Class 1, WM-Curtail	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
DSM, Class 1, WM-Sch-TES	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
DSM, Class 1, YA-Curtail	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
DSM, Class 1, YA-Sch-TES	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
DSM, Class 1 & 3 Total	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	32	63
DSM, Class 2, WM	28	28	31	31	31	31	31	31	31	20	21	20	20	20	20	20	20	21	21	21	292	497
DSM, Class 2, YA	5	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	61	126
DSM, Class 2 Total	36	38.1	40	40	40	41	40	40	40	30	30	30	30	29	30	31	30	30	30	30	385	686
Fuel Cell	-	-	-	-	5	5	25	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
FOT COB Flat	-	-	30	389	-	-	289	239	-	-	338	338	338	338	338	-	338	338	338	338	95	199
FOT COB Q3	-	-	-	-	389	389	-	-	239	239	-	-	-	-	-	338	-	-	-	-	126	80
FOT MidColumbia Q3	-	-	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	280	340
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	115	120	127	339	330	322	334	315	N/A	250
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	296	424	182	229	143	291	215	221	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	27	-	298	156	291	157	19	53	N/A	125
Annual Additions, Long Term Resources	275	377	194	907	784	1,057	960	1,022	286	458	98	96	99	101	102	118	983	106	103	103		
Annual Additions, Short Term Resources	75	50	180	1,183	1,179	1,089	989	932	1,015	1,384	1,522	1,584	1,825	1,931	2,062	2,111	2,477	2,627	2,778	2,944		
Total Annual Additions	350	427	374	2,090	1,963	2,147	1,950	1,954	1,301	1,843	1,620	1,680	1,924	2,032	2,164	2,229	3,460	2,732	2,882	3,047		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Case 47b

PVRR: $21,785

		Nameplate Capacity, MW																				Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
East																							
	UT Pulverized Coal	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	600
	IC Aero	-	-	-	-	348	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	609	609
	East PPA	-	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	-	-	-	-	-	-	-	-	-	128	128
	Wind, GO, 24	-	-	-	-	-	-	-	-	49	171	-	-	-	-	-	-	-	-	-	-	221	221
	Wind, GO, 29	-	-	-	-	-	-	4	187	108	-	-	-	-	-	-	-	-	-	-	-	300	300
	Wind, Project I	-	-	-	-	-	-	-	140	-	-	-	-	-	-	-	-	-	-	-	-	140	140
	Wind, Project II	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Duke Energy PPA	-	99.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, HighPlains	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
	Wind, WYSW, 35	-	-	-	-	-	-	-	-	-	-	-	-	-	23	750	527	-	-	-	-	-	1,300
	Total Wind	99	99	-	-	-	-	4	327	158	331	-	-	-	23	750	527	-	-	-	-	1,018	2,318
	CHP - Biomass	2	2.0	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	20	20
	CHP - Reciprocating Engine	1	0.6	1	1	1	1	2	2	2	2	2	2	2	2	2	2	-	-	-	-	12	21
	Distributed Standby Generation	8	7.5	8	8	8	8	8	8	4	4	-	-	-	-	-	-	-	-	-	-	68	68
	DSM, Class 1, UT-Coolkeeper	25	50	40	30	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	205	205
	DSM, Class 1, GO-Curtail	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1, GO-DLC-RES	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
	DSM, Class 1, GO-Irrigate	-	-	-	-	1.2	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3	6.3
	DSM, Class 1, GO-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	29.9	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	29.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	24.1	14.6	-	-	-	-	-	-	-	-	-	-	-	-	-	38.7	38.7
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	6.4	6.4
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	7.4
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.8
	DSM, Class 1, WY-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1 & 3 Total	25	50.0	40	30	11	39	71	10	10	10	-	-	-	-	-	-	-	-	-	-	296	296
	DSM, Class 2, GO	2	2.0	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	2	22	43
	DSM, Class 2, UT	41	48.7	44	44	49	51	51	45	46	48	47	48	49	51	52	52	50	53	54	55	467	979
	DSM, Class 2, WY	1	3.1	6	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	69	166
	DSM, Class 2 Total	43	53.7	52	55	60	62	62	56	57	59	58	59	60	62	64	64	63	66	66	67	559	1,187
	FOT Utah Q3	-	-	-	28	-	50	50	50	-	50	-	-	-	50	-	-	-	-	-	-	23	14
	FOT Mead Q3	-	-	-	-	-	-	-	-	526	600	480	517	600	600	600	600	600	600	600	600	113	346
	FOT Mona/Nevada Utah Border	75	50	150	350	200	200	200	200	200	200	170	200	-	-	-	-	-	-	-	-	183	110
	Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	178	173	170	39	-	18	42	90	N/A	89
	Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	62	105	64	-	-	-	-	-	N/A	29
West																							
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
	Swift Hydro Upgrades*	-	-	-	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind PPA	45	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Total Wind	45	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	65
	Utility Biomass	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Reciprocating Engine	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	6	6
	Distributed Standby Generation	3	3	3	3	3	3	3	3	1	1	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, WW-Curtail	-	-	-	-	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.5
	DSM, Class 1, WW-DLC-RES	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	1.5
	DSM, Class 1, WW-Irrigate	-	-	-	-	-	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
	DSM, Class 1, WW-Sch-TES	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	4.1
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	4.2	4.2
	DSM, Class 1, WM-Irrigate	-	-	-	-	-	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.5	12.5
	DSM, Class 1, WM-Sch-TES	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	DSM, Class 1, YA-Curtail	-	-	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9
	DSM, Class 1, YA-Irrigate	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	5.5
	DSM, Class 1, YA-Sch-TES	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.2
	DSM, Class 1 & 3 Total	-	-	-	-	-	20	13	-	-	-	-	-	-	-	-	-	-	-	-	-	33	33

Case 47b

PVRR: $21,785

	Nameplate Capacity, MW																				Resource Sum, FOT Avg	
Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year	20 Year *
DSM, Class 2, WA	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	30	59
DSM, Class 2, WM	28	28	30	30	31	31	31	31	31	20	20	20	20	20	20	20	20	20	20	20	290	493
DSM, Class 2, YA	5	6	6	5	5	6	6	5	5	6	6	6	6	6	6	6	6	6	6	6	55	116
DSM, Class 2 Total	35	36.5	39	39	39	39	40	39	39	29	29	29	30	29	29	30	29	30	30	30	375	668
FOT COB Flat	-	-	47	389	389	389	289	239	239	239	338	338	338	338	338	338	338	338	338	338	222	280
FOT Mid Columbia Flat	-	-	-	-	-	-	-	203	-	227	-	-	-	-	27	128	104	167	178	202	43	62
FOT MidColumbia Q3	-	-	-	400	390	400	400	197	-	-	-	-	-	-	-	-	-	-	-	-	179	89
FOT West Main Q3	-	-	-	50	50	50	50	50	50	50	-	-	50	50	50	50	50	50	50	50	35	38
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	73	74	75	103	99	104	103	153	N/A	98
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	24	33	155	298	393	520	577	N/A	250
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	177	178	182	160	156	147	N/A	125
Annual Additions, Long Term Resources	265	326	187	400	511	214	230	717	275	440	688	89	92	116	844	622	92	95	96	97		
Annual Additions, Short Term Resources	75	50	197	1,217	1,030	1,089	989	939	1,015	1,366	987	1,054	1,301	1,413	1,534	1,589	1,672	1,830	1,987	2,157		
Total Annual Additions	340	376	385	1,617	1,541	1,303	1,220	1,657	1,291	1,806	1,676	1,143	1,392	1,529	2,378	2,212	1,764	1,925	2,083	2,254		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

RESOURCE DIFFERENCES, B-SERIES LESS CORRESPONDING ORIGINAL PORTFOLIOS

Table A.19 – Resource Capacity Differences, Case 2B less Original Case 2 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Dist. Gen	4	4	4	4	4	16	6	6	2	(1)	(1)	(1)	50	41
	Wind	-	-	-	-	-	-	140	-	-	(140)	-	-	-	659
	DSM	2.9	3.4	4.2	6.6	6.0	52.8	51.7	6.3	-	0.4	-	-	134.3	135.8
	Market Purchase	75	50	150	259	263	50	41	6	175	173	210	271	124	48
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		58
West															
	Gas	-	-	-	-	-	287	-	-	-	-	-	-	287	287
	Dist. Gen	2	2	2	2	2	2	2	2	-	-	-	(1)	17	13
	Other Renewables	-	-	-	-	-	-	25	25	-	-	-	-	50	50
	DSM	0.5	0.7	0.6	0.1	1.1	20.8	15.5	0.5	(0.5)	-	-	-	39.6	39.6
	Market Purchase	-	-	(176)	237	222	101	-	-	(170)	(163)	(200)	(259)	5	(9)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		62
	Annual Additions, Long Term Resources	10	10	11	(594)	13	379	240	40	1	(140)	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(26)	495	485	151	41	6	5	10	11	12		
	Total Annual Additions	85	60	(15)	(99)	498	530	280	46	6	(129)	10	11		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.20 – Resource Capacity Differences, Case 5B less Original Case 5 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Clean Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	(346)
	Gas	-	-	-	-	-	261	-	(261)	-	-	-	-	-	-
	Dist. Gen	4	4	4	4	4	16	34	14	-	-	(1)	(1)	84	81
	Wind	-	-	-	-	-	-	451	750	-	(651)	(400)	-	550	-
	Other Renewables	-	-	-	-	-	-	-	35	-	-	-	-	35	35
	DSM	2.9	3.1	3.0	6.6	4.1	76.2	22.2	14.1	-	-	-	-	132.1	142.1
	Market Purchase	75	50	150	252	265	50	50	25	196	12	26	50	113	(14)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		149
West															
	Gas	-	-	-	-	-	-	-	130	-	-	-	-	130	130
	Dist. Gen	2	2	2	2	2	2	2	12	-	-	(1)	(1)	25	22
	Other Renewables	-	-	-	-	-	-	25	60	-	-	-	-	85	85
	DSM	1.3	0.7	0.6	0.1	1.5	21.5	6.3	9.7	-	-	-	-	41.8	41.8
	Market Purchase	-	-	(175)	244	222	104	4	-	(171)	27	23	(0)	26	(45)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		233
	Annual Additions, Long Term Resources	11	10	10	(594)	11	376	539	763	-	(651)	(402)	(1)		
	Annual Additions, Short Term Resources	75	50	(25)	496	487	154	54	25	25	39	49	50		
	Total Annual Additions	86	60	(15)	(98)	498	530	593	788	25	(611)	(353)	49		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.21 – Resource Capacity Differences, Case 5B CCCT Dry less Original Case 5B Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	536	-	-	-	-	-	-	536	536
	Dist. Gen	-	-	4	4	4	2	4	4	-	-	-	-	21	21
	Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-
	DSM	0.2	0.5	-	-	-	-	0.8	-	-	-	-	-	1.4	1.4
	Market Purchase	75	50	150	277	294	-	27	25	196	-	-	1	109	(20)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		96
West															
	Dist. Gen	-	-	2	2	2	-	2	2	-	-	-	-	8	8
	Other Renewables	-	-	-	-	-	-	-	-	-	-	-	-	-	50
	DSM	1.3	-	-	-	0.2	0.5	0.1	-	-	-	-	-	2.1	2.1
	Market Purchase	-	-	(156)	244	222	35	4	-	(171)	25	22	21	20	(2)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		193
	Annual Additions, Long Term Resources	2	0	5	(601)	6	539	6	5	-	-	150	-		
	Annual Additions, Short Term Resources	75	50	(6)	521	516	35	30	25	25	25	22	22		
	Total Annual Additions	77	50	(1)	(80)	522	574	36	31	25	25	172	22		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.22 – Resource Capacity Differences, Case 5B CCCT Wet less Original Case 5 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	570	-	-	-	-	-	-	570	570
	Dist. Gen	-	-	-	1	-	-	-	-	-	-	-	-	1	-
	Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-
	Market Purchase	75	50	150	286	308	-	17	21	192	-	-	-	110	(20)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		76
West															
	Dist. Gen	-	-	-	-	1	-	-	-	-	-	-	-	1	0
	Other Renewables	-	-	-	-	-	-	-	-	-	-	-	-	-	50
	DSM	1.3	-	-	-	-	0.2	0.1	-	-	-	-	-	1.6	1.6
	Market Purchase	-	-	(151)	244	222	21	4	-	(171)	21	18	18	19	6
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		187
	Annual Additions, Long Term Resources	1	0	-	(606)	1	570	0	-	-	-	150	-		
	Annual Additions, Short Term Resources	75	50	(1)	531	530	21	21	21	21	21	18	18		
	Total Annual Additions	76	50	(1)	(76)	531	591	21	21	21	21	167	18		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.23 – Resource Capacity Differences, Case 8B less Original Case 8 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	3	1	1	7	(1)	5	29	(2)	-	-	(1)	(1)	42	40
	Wind	-	-	-	41	-	464	(6)	(193)	(158)	(249)	-	-	(100)	(100)
	Other Renewables	-	-	-	-	35	-	-	-	-	-	-	-	35	35
	DSM	5.0	10.1	5.2	7.2	4.3	94.9	3.7	(6.1)	(0.0)	(0.5)	-	-	123.9	123.9
	Market Purchase	75	50	150	271	156	50	50	-	177	-	-	10	98	(18)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		252
West															
	Dist. Gen	2	1	1	-	-	5	30	(2)	-	-	(1)	(1)	37	35
	Other Renewables	-	-	-	-	35	-	-	(35)	-	-	-	-	-	-
	DSM	0.8	0.9	0.8	1.4	1.3	35.7	1.1	(0.6)	-	-	-	-	41.4	41.4
	Market Purchase	-	-	(174)	230	270	180	119	-	(163)	40	36	27	50	(28)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		151
	Annual Additions, Long Term Resources	11	12	7	(550)	75	605	58	23	(158)	(249)	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(24)	501	425	230	169	-	14	40	36	37		
	Total Annual Additions	86	62	(17)	(50)	500	835	227	23	(144)	(209)	34	35		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.24 – Resource Capacity Differences, Case 9B less Original Case 9 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Clean Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	(346)
	Gas	-	-	-	-	-	261	-	(261)	-	-	-	-	-	-
	Dist. Gen	4	4	4	4	4	10	45	9	-	-	(1)	(1)	84	81
	Wind	-	-	-	-	-	100	451	750	(444)	(536)	(305)	(15)	320	0
	Other Renewables	-	-	-	-	-	-	-	35	-	-	-	-	35	35
	DSM	2.9	2.5	3.0	6.6	6.1	73.8	22.7	13.8	-	-	-	-	131.3	141.3
	Market Purchase	75	50	150	373	465	152	52	24	33	45	52	53	142	4
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		104
West															
	Gas	-	-	-	-	-	-	-	130	-	-	-	-	130	130
	Dist. Gen	2	2	2	2	2	2	2	12	-	-	(1)	(1)	26	22
	Other Renewables	-	-	-	-	-	-	25	60	-	-	-	-	85	85
	DSM	1.3	0.7	0.6	0.1	1.2	21.5	6.7	9.1	-	-	-	-	41.3	41.4
	Market Purchase	-	-	(175)	124	21	-	-	-	-	-	-	-	(3)	(1)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		127
	Annual Additions, Long Term Resources	11	10	10	(594)	13	468	551	757	(444)	(536)	(306)	(16)		
	Annual Additions, Short Term Resources	75	50	(25)	497	486	152	52	24	33	45	52	53		
	Total Annual Additions	86	60	(15)	(97)	499	620	603	781	(411)	(492)	(254)	38		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.25 – Resource Capacity Differences, Case 10B less Original Case 10 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	4	4	4	4	21	9	20	(4)	-	-	(1)	(1)	61	60
	Wind	-	-	-	-	139	359	-	(191)	(158)	(248)	189	-	(100)	89
	Other Renewables	-	-	-	-	-	35	-	(35)	-	-	-	-	-	-
	DSM	6.8	7.0	5.2	7.2	7.9	97.1	2.1	(6.0)	(0.1)	(0.5)	-	-	126.7	126.7
	Market Purchase	75	50	150	354	423	187	73	(0)	122	114	69	28	155	18
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		266
West															
	Dist. Gen	2	2	2	2	7	7	32	(2)	-	-	(1)	(1)	51	49
	Wind	-	-	-	-	-	100	-	(100)	-	-	-	-	-	-
	Other Renewables	-	-	-	-	-	35	-	(35)	-	-	-	-	-	-
	DSM	0.5	1.0	0.8	1.6	1.3	35.3	0.5	-	-	-	-	-	41.0	41.0
	Market Purchase	-	-	(183)	134	42	-	50	-	(107)	(74)	(7)	36	(14)	(5)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		16
	Annual Additions, Long Term Resources	14	14	12	(593)	175	677	54	(111)	(158)	(249)	188	(1)		
	Annual Additions, Short Term Resources	75	50	(33)	488	465	187	123	(0)	14	40	62	63		
	Total Annual Additions	89	64	(21)	(105)	640	863	177	(112)	(144)	(209)	251	62		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.26 – Resource Capacity Differences, Case 17B less Original Case 17 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	4	4	4	4	4	4	44	-	-	-	(1)	(1)	67	66
	Wind	-	-	169	138	-	-	(0)	(288)	(68)	(250)	-	-	(300)	(300)
	DSM	7.2	4.0	0.5	3.0	8.6	94.3	12.5	(0.4)	(7.3)	(0.4)	-	-	121.9	121.9
	Market Purchase	75	50	150	265	171	68	50	45	182	-	-	-	106	(7)
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		310
West															
	Dist. Gen	2	2	2	2	2	2	12	-	-	-	(1)	(1)	22	21
	Wind	-	-	138	(138)	-	-	-	-	-	500	-	-	500	500
	DSM	0.8	1.0	0.6	0.7	0.9	27.7	7.9	0.1	(0.2)	-	-	-	39.6	39.6
	Market Purchase	-	-	(183)	189	271	257	239	14	(111)	97	92	94	77	13
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		77
	Annual Additions, Long Term Resources	14	11	313	(598)	15	127	76	(27)	(76)	249	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(33)	454	442	326	289	60	71	97	92	94		
	Total Annual Additions	89	61	281	(144)	457	453	364	33	(5)	346	91	92		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

Table A.27 – Resource Capacity Differences, Case 18B less Original Case 18 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	-	-	-	261	-	-	-	-	261	261
	Dist. Gen	4	4	4	4	9	9	34	-	-	-	(1)	-	66	66
	Wind	-	-	-	223	-	-	264	206	(588)	(404)	-	-	(300)	(300)
	DSM	6.8	6.9	5.2	7.2	4.9	97.0	1.6	(0.4)	(6.1)	(0.5)	-	-	122.6	127.0
	Market Purchase	75	50	150	344	340	250	219	29	21	71	70	70	155	28
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		144
West															
	Dist. Gen	2	2	2	2	7	7	27	-	-	-	(1)	(1)	47	46
	Other Renewables	-	-	-	-	35	(35)	-	-	-	-	-	-	-	-
	DSM	0.5	0.9	0.8	1.7	1.3	35.0	0.5	-	-	-	-	-	40.7	40.7
	Market Purchase	-	-	(182)	140	95	29	20	-	26	3	-	-	13	7
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		122
	Annual Additions, Long Term Resources	14	14	12	(370)	56	112	326	467	(594)	(405)	(1)	(1)		
	Annual Additions, Short Term Resources	75	50	(32)	484	434	279	240	29	46	74	70	70		
	Total Annual Additions	89	64	(20)	114	491	391	566	496	(548)	(331)	68	69		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

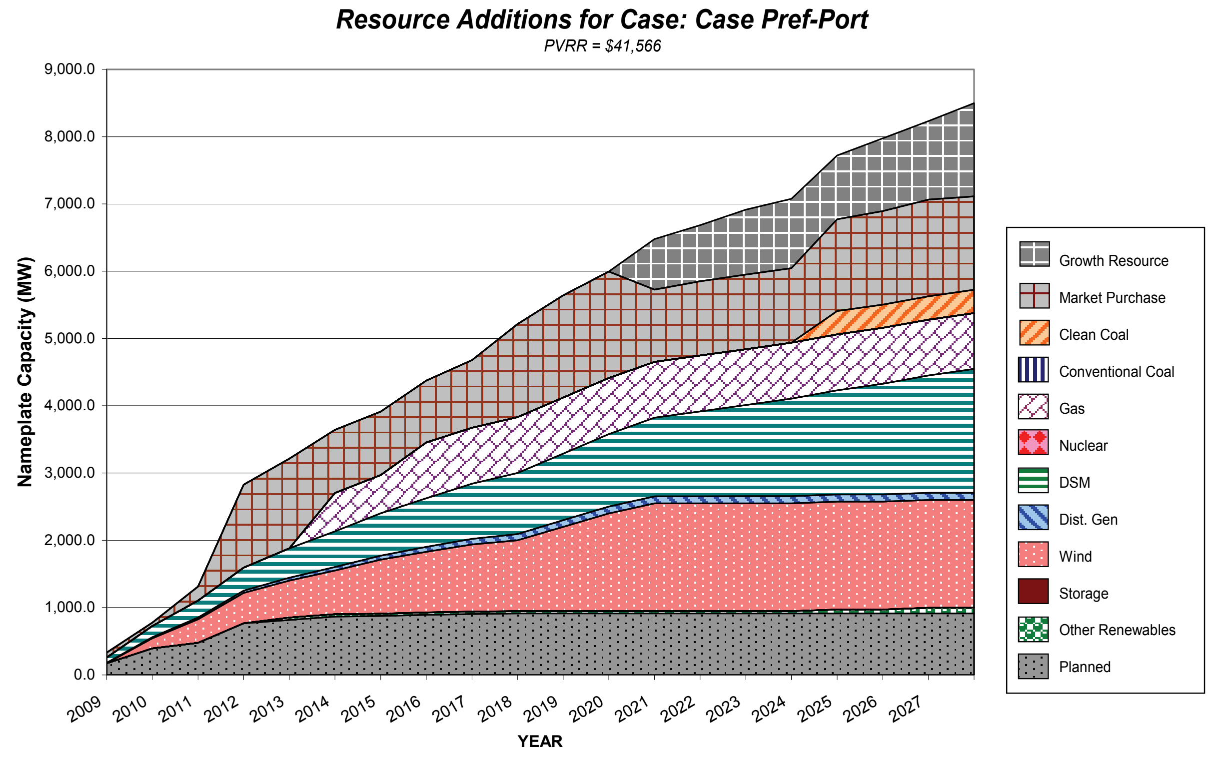
Table A.28 – Resource Capacity Differences, Case 47B less Original Case 47 Portfolio

		Nameplate Capacity, MW												Resource Sum, FOT Avg	
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year	20 Year *
East															
	Planned Resource	-	-	-	(607)	-	-	-	-	-	-	-	-	(607)	(607)
	Gas	-	-	-	-	174	-	-	261	-	-	-	-	435	435
	Dist. Gen	1	1	1	1	-	-	-	-	-	-	(1)	(1)	2	(0)
	Wind	-	-	-	-	-	-	4	(6)	(0)	-	-	(24)	(2)	776
	DSM	0.9	3.3	2.2	2.4	6.3	34.7	66.1	(5.8)	-	0.7	0.4	-	110.8	114.3
	Market Purchase	75	50	150	227	56	50	50	-	160	-	239	250	82	12
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		86
West															
	Dist. Gen	1	1	1	1	1	-	-	-	1	-	-	(1)	4	0
	Other Renewables	-	-	-	-	-	-	25	-	-	-	-	-	25	25
	DSM	-	-	0.6	0.1	1.1	20.8	13.3	(21.5)	0.1	-	-	-	14.7	14.7
	Market Purchase	-	-	(158)	295	304	256	155	-	(161)	(1)	(240)	(249)	69	34
	Growth Resource	-	-	-	-	-	-	-	-	-	-	-	-		36
	Annual Additions, Long Term Resources	2	4	4	(603)	182	55	109	228	0	1	(0)	(25)		
	Annual Additions, Short Term Resources	75	50	(8)	521	360	306	205	-	(1)	(1)	(1)	1		
	Total Annual Additions	77	54	(4)	(82)	542	361	314	228	(0)	(0)	(1)	(25)		

** For the 20 Year column "Growth Stations" are an 8 year average reflecting the available years from 2021-2028.*

2008 PREFERRED PORTFOLIO

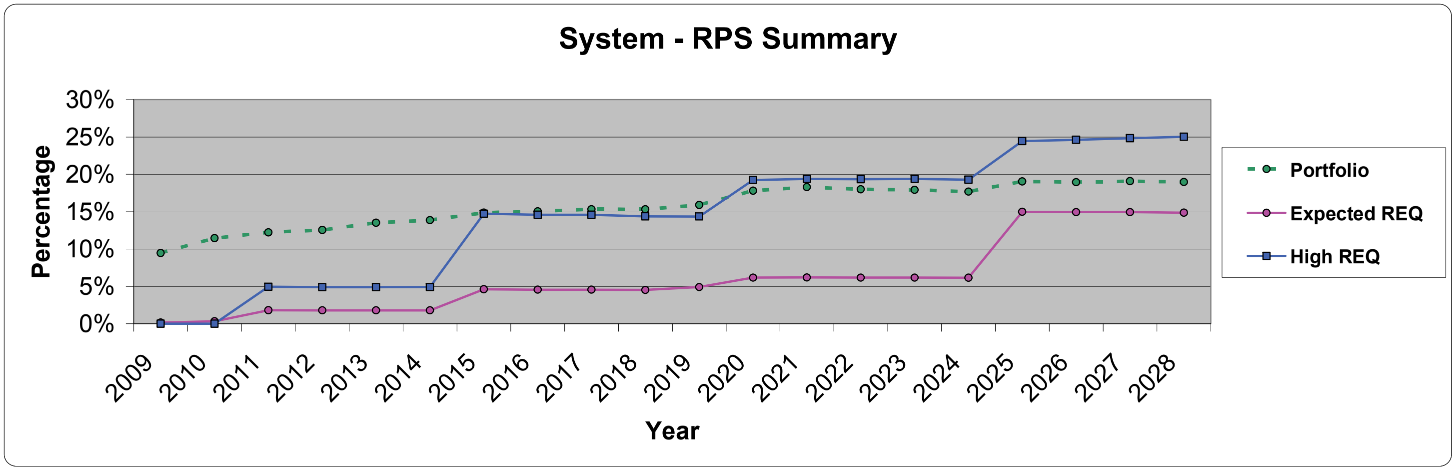
This section consists of tables and charts showing System Optimizer results for the 2008 IRP preferred portfolio.



Notes:
1/ Growth resource: Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.
2/ Market Purchase: Firm market products ("front office transactions") procured on a forward basis at market hubs reflected in the IRP models and subject to annual availability limits.
3/ Planned resource: includes the 2012 RFP CCCT, Swift Hydro & coal turbine upgrades, a 2012 Utah power purchase agreement, 263 MW of owned and purchased wind generation added by 2010, and expansion of the Utah Cool Keeper DSM program (205 MW by 2018).

System - RPS Report - Case # Pref-Port

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System																				
RPS Requirement - Energy GWh																				
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,257	5,301	5,358	5,391
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	-	-	122	122	122	123	370	372	375	377	632	636	640	644	647	651	655	659	662	666
Oregon	-	-	701	708	720	732	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Total RPS Requirement	88	176	1,007	1,023	1,046	1,068	2,821	2,849	2,884	2,908	3,195	4,067	4,113	4,139	4,174	4,209	10,326	10,400	10,500	10,577
Bank Balance																				
Utah	5,550	8,912	12,527	16,289	20,396	24,704	29,132	33,718	38,459	43,277	48,380	53,776	59,382	64,937	70,507	76,072	76,484	76,874	77,311	77,737
Other (ID,WY)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	336	582	516	598	686	507	325	372	406	211	46	117	135	118	110	111	106	104	101
Oregon	1,376	2,640	3,322	4,080	4,987	5,946	5,455	5,031	4,659	4,322	4,116	3,250	2,454	1,601	713	-	-	-	-	-
Cumulative Surplus Credit Bank Balance	**6,926**	**11,887**	**16,432**	**20,885**	**25,982**	**31,336**	**35,094**	**39,073**	**43,490**	**48,004**	**52,707**	**57,072**	**61,953**	**66,673**	**71,338**	**76,182**	**76,595**	**76,980**	**77,415**	**77,838**
Adjusted Qualifying Renewables																				
Utah	2,950	3,361	3,616	3,762	4,107	4,307	4,428	4,586	4,741	4,818	5,104	5,396	5,606	5,555	5,570	5,565	5,670	5,690	5,795	5,817
Other (ID,WY)	823	1,130	1,263	1,354	1,521	1,622	1,686	1,781	1,867	1,902	2,059	2,227	2,347	2,315	2,320	2,280	2,346	2,363	2,430	2,446
California	88	176	185	194	204	213	223	233	243	253	263	336	339	341	345	348	352	354	357	360
Washington	264	336	368	391	451	479	520	547	572	586	634	679	714	705	704	703	713	708	717	712
Oregon	982	1,264	1,383	1,465	1,627	1,691	2,228	2,244	2,266	2,277	2,300	3,096	3,133	3,154	3,182	3,211	4,061	4,087	4,123	4,160
Adjusted Qualifying Renewables	**5,108**	**6,266**	**6,815**	**7,166**	**7,910**	**8,314**	**9,086**	**9,391**	**9,689**	**9,836**	**10,360**	**11,733**	**12,139**	**12,069**	**12,121**	**12,107**	**13,142**	**13,201**	**13,422**	**13,495**
System Load	53,963	54,666	55,678	57,151	58,499	59,922	61,152	62,411	63,213	64,270	65,181	65,879	66,387	67,024	67,665	68,456	68,968	69,631	70,300	71,140
Portfolio	9%	11%	12%	13%	14%	14%	15%	15%	15%	15%	16%	18%	18%	18%	18%	18%	19%	19%	19%	19%
Portfolio Meets RPS																				
Expected REQ %	0%	0%	2%	2%	2%	2%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	15%	15%	15%	15%



Study Description

CO2 Type = CO2 tax, CO2 Cost = $45, Gas = Low - June 2008, Load Growth = Medium, Renewable Std = None, Baseload Plant Avail = Base, Plant Cost = Base, Rsv Margin = 0.12, Class 3 DSM = Excluded, (No Lakeside II - CCCT -WC)

APPENDIX B – STOCHASTIC PRODUCTION COST SIMULATION RESULTS

This appendix reports additional results for the Monte Carlo production cost simulations conducted with PacifiCorp's Planning and Risk model. These results supplement the data presented in Chapter 8 of the main IRP document. The results presented include the following:

- Stochastic risk and other portfolio performance measures for the additional portfolios modeled to support a 2012 gas resource deferral strategy (referred to as the "B series" in this appendix)

- A component cost breakdown of the stochastic mean Present Value of Revenue Requirements (PVRR) reported for all the portfolios.

Table B.1 – Stochastic Mean PVRR by CO_2 Tax Level, B Series Portfolios

Case	CO2 Tax (Million 2009$)			
	$0/ton	$45/ton	$100/ton	Average
2B	22,126	40,062	60,448	40,879
5B	22,554	39,452	58,664	40,224
5B_CCCT Dry	22,462	39,369	58,751	40,194
5B_CCCT Wet	22,457	39,315	58,639	40,137
8B	23,402	39,673	57,809	40,295
9B	22,778	39,725	59,031	40,511
10B	23,921	40,261	58,542	40,908
17B	25,569	40,539	56,798	40,968
18B	25,102	40,353	57,136	40,864
47B	22,658	40,507	60,872	41,346

Table B.2 – Stochastic Risk Results by CO_2 Tax Level, B Series Portfolios

Case	Risk Measure by CO2 Tax Level (Million 2009$)			
	Production Cost Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
$0/ton CO2 Tax				
2B	8,702	12,646	36,914	50,630
5B	8,859	13,441	37,820	51,782
5B_CCCT Dry	9,140	13,595	37,386	52,993
5B_CCCT Wet	9,103	13,601	37,349	52,874
8B	8,267	14,270	37,697	50,203
9B	8,955	13,644	38,113	52,426
10B	8,350	14,832	38,506	51,241
17B	7,583	16,363	38,434	49,330
18B	7,905	15,901	38,712	50,424

Case	Risk Measure by CO2 Tax Level (Million 2009$)			
	Production Cost Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
47B	8,737	13,367	37,074	51,363
$45/ton CO2 Tax				
2B	11,114	25,686	59,314	73,178
5B	11,211	25,130	59,065	73,171
5B_CCCT Dry	11,480	24,932	58,565	74,252
5B_CCCT Wet	11,433	24,917	58,391	74,029
8B	10,593	26,224	58,397	70,946
9B	11,303	25,304	59,415	73,857
10B	10,720	26,463	59,354	72,143
17B	9,825	26,977	57,866	68,742
18B	10,178	27,621	58,429	70,111
47B	11,165	26,098	59,398	73,800
$100/ton CO2 Tax				
2B	16,792	38,762	90,087	106,209
5B	16,817	36,998	88,526	104,917
5B_CCCT Dry	17,186	37,396	88,207	106,410
5B_CCCT Wet	17,142	37,433	87,959	106,144
8B	16,038	36,943	86,765	101,179
9B	16,912	37,252	88,957	105,723
10B	16,250	37,635	88,046	102,765
17B	14,990	37,546	84,231	96,591
18B	15,453	37,354	85,373	98,767
47B	16,941	39,461	90,319	107,006
CO2 Tax Average				
2B	12,202	25,698	62,105	76,672
5B	12,296	25,190	61,804	76,623
5B_CCCT Dry	12,602	25,308	61,386	77,885
5B_CCCT Wet	12,559	25,317	61,233	77,682
8B	11,633	25,813	60,953	74,109
9B	12,390	25,400	62,162	77,335
10B	11,773	26,310	61,969	75,383
17B	10,799	26,962	60,177	71,554
18B	11,179	26,959	60,838	73,101
47B	12,281	26,308	62,264	77,390

Table B.3 – B Series Cases, Portfolio Emissions Externality Cost by CO$_2$ Adder Level

Case	Incremental Stochastic Mean PVRR by CO$_2$ Tax Level (Million 2009$)			
	$0/ton	$45/ton	$100/ton	Average
2B	0	17,936	38,322	28,129
5B	0	16,898	36,110	26,504
5B_CCCT Dry	0	16,907	36,289	26,598

Case	Incremental Stochastic Mean PVRR by CO_2 Tax Level (Million 2009$)			
	$0/ton	$45/ton	$100/ton	Average
5B_CCCT Wet	0	16,858	36,182	26,520
8B	0	16,272	34,408	25,340
9B	0	16,947	36,253	26,600
10B	0	16,340	34,620	25,480
17B	0	14,970	31,228	23,099
18B	0	15,252	32,034	23,643
47B	0	17,848	38,214	28,031

Table B.4 – B Series Cases, CO_2 Cost Exposure (non-weighted)

Case	CO2 Opportunity Loss by CO2 Tax Level, Million Dollars (2009$)			Maximum Loss	Rank
	$0/ton	$45/ton	$100/ton		
2B	-	793	3,943	3,943	9
5B	474	171	2,081	2,081	4
5B_CCCT Dry	360	62	2,152	2,152	5
5B_CCCT Wet	353	-	2,028	2,028	3
8B	1,315	359	1,139	1,315	1
9B	712	461	2,470	2,470	6
10B	1,875	994	1,935	1,935	2
17B	3,520	1,198	-	3,520	8
18B	3,066	1,040	396	3,066	7
47B	541	1,242	4,379	4,379	10

Table B.5 – B Series Cases, Customer Rate Impact

Case	Customer Rate Impact by CO2 Tax Level ($/MWh)				Rank
	$0/ton	$45/ton	$100/ton	Average	
2B	3.00	6.42	10.12	6.51	8
5B	3.03	6.25	9.74	6.34	4
5B_CCCT Dry	3.06	6.22	9.65	6.31	2
5B_CCCT Wet	3.05	6.20	9.62	6.29	1
8B	3.19	6.31	9.62	6.38	5
9B	3.02	6.24	9.73	6.33	3
10B	3.32	6.45	9.79	6.52	10
17B	3.67	6.43	9.26	6.45	7
18B	3.59	6.40	9.32	6.44	6
47B	3.05	6.43	10.08	6.52	9

Table B.6 – B Series Cases, Average Annual Energy Not Served

Case	Energy Not Served, Average Annual GWh, 2009-2028	Rank
2B	132.2	3
5B	169.7	9
5B_CCCT Dry	153.7	6
5B_CCCT Wet	152.4	5
8B	154.5	7
9B	184.3	10
10B	156.7	8
17B	131.7	2
18B	144.6	4
47B	131.3	1

Table B.7 – B Series Cases, Loss of Load Probability for a Major July Event

Case	Probability of ENS Event > 25,000 MWh in July (Annual average, 2009-2028)	Rank
2B	16.7%	1
5B	18.2%	7
5B_CCCT Dry	17.8%	6
5B_CCCT Wet	17.8%	5
8B	17.7%	4
9B	19.3%	10
10B	18.4%	8
17B	17.1%	2
18B	17.1%	2
47B	18.5%	9

Table B.8 – B Series Cases, Capital Costs for 2009-2018

Case	Net Present Value, (Thousand 2009$)	Rank
2B	580,304	1
5B	1,271,802	5
5B_CCCT Dry	744,635	3
5B_CCCT Wet	756,891	4
8B	2,417,994	8
9B	1,335,078	6
10B	2,164,993	7
17B	3,624,235	10
18B	3,013,923	9
47B	641,136	2

PROBABILITY-WEIGHTED STOCHASTIC MEASURE RESULTS

Tables B.9 and B.10 report the stochastic cost results for expected value CO_2 tax levels ranging from $15 to $70. The expected value CO_2 tax levels reflect probability weights applied to stochastic mean cost values for the three Monte Carlo simulations conducted for each portfolio at $0, $45, and $100 CO_2 tax values.

Table B.9 – Original Portfolio Stochastic Cost Results

Case	Expected Value CO2 Tax ($/ton)											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
Risk-adjusted PVRR, Million Dollars (2009$)												
1	30,487	32,588	34,505	36,603	38,708	40,813	42,918	45,022	47,127	51,632	51,337	53,442
2	29,962	32,050	33,955	36,002	38,056	40,110	42,164	44,218	46,272	50,677	50,380	52,434
3	32,372	34,236	35,936	37,697	39,464	41,231	42,998	44,765	46,533	50,961	50,067	51,834
5	30,453	32,423	34,219	36,152	38,092	40,031	41,971	43,910	45,850	50,226	49,729	51,668
8	30,789	32,681	34,406	36,234	38,068	39,903	41,737	43,571	45,406	49,734	49,074	50,909
9	30,575	32,544	34,339	36,272	38,210	40,149	42,087	44,026	45,965	50,352	49,842	51,781
10	31,504	33,389	35,109	36,948	38,794	40,639	42,484	44,330	46,175	50,588	49,866	51,712
11	33,043	34,845	36,489	38,192	39,900	41,609	43,318	45,026	46,735	51,191	50,153	51,862
14	34,835	36,586	38,183	39,808	41,439	43,070	44,702	46,333	47,964	52,537	51,226	52,858
17	32,562	34,305	35,895	37,559	39,230	40,900	42,570	44,240	45,910	50,297	49,250	50,920
18	32,478	34,247	35,861	37,558	39,262	40,965	42,669	44,372	46,075	50,480	49,482	51,186
19	32,937	34,686	36,281	37,954	39,633	41,311	42,990	44,669	46,348	50,780	49,706	51,385
20	35,293	36,904	38,373	39,885	41,403	42,920	44,438	45,955	47,473	52,022	50,508	52,026
22	36,646	38,279	39,769	41,277	42,791	44,305	45,820	47,334	48,849	53,523	1,877	53,392
24	37,077	38,624	40,037	41,471	42,911	44,350	45,790	47,230	48,670	53,339	51,549	52,989
25	34,237	35,896	37,410	38,976	40,548	42,120	43,692	45,264	46,836	51,318	49,979	51,551
26	36,850	38,424	39,860	41,330	42,808	44,285	45,762	47,239	48,716	53,392	51,670	53,148
27	37,041	38,591	40,005	41,441	42,883	44,324	45,766	47,208	48,650	53,317	51,533	52,975
29	39,348	40,885	42,289	43,709	45,136	46,563	47,990	49,416	50,843	55,730	53,697	55,124
46	31,620	33,678	35,556	37,571	39,592	41,614	43,635	45,656	47,678	52,224	51,720	53,742
47	30,622	32,689	34,574	36,600	38,632	40,665	42,697	44,730	46,763	51,219	50,828	52,861
Cost Exposure for CO2 Tax Scenarios, Million Dollars (2009$)												
1	646	698	745	997	1,250	1,503	1,756	2,009	2,262	2,564	2,768	3,021
2	120	160	195	397	599	801	1,003	1,205	1,407	1,609	1,811	2,013
3	2,530	2,345	2,176	2,091	2,007	1,922	1,837	1,752	1,668	1,893	1,498	1,413
5	612	532	460	547	634	722	810	897	985	1,158	1,160	1,247
8	948	790	646	629	611	593	576	558	541	667	505	488
9	734	653	580	666	753	839	926	1,013	1,100	1,284	1,273	1,360
10	1,662	1,499	1,349	1,343	1,336	1,330	1,323	1,317	1,310	1,521	1,297	1,291
11	3,201	2,954	2,729	2,586	2,443	2,300	2,157	2,013	1,870	2,123	1,584	1,441
14	4,993	4,695	4,423	4,203	3,982	3,761	3,540	3,320	3,099	3,470	2,658	2,437
17	2,720	2,414	2,136	1,954	1,772	1,590	1,408	1,227	1,045	1,230	681	499
18	2,636	2,356	2,102	1,953	1,804	1,656	1,507	1,359	1,210	1,412	913	765
19	3,096	2,795	2,521	2,348	2,175	2,002	1,829	1,656	1,483	1,713	1,137	964
20	5,451	5,013	4,614	4,280	3,945	3,611	3,277	2,942	2,608	2,955	1,939	1,605
22	6,804	6,388	6,009	5,671	5,334	4,996	4,659	4,321	3,984	4,455	3,308	2,971
24	7,235	6,734	6,277	5,865	5,453	5,041	4,629	4,217	3,805	4,271	2,981	2,568

Case	Expected Value CO2 Tax ($/ton)											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
25	4,396	4,005	3,651	3,371	3,091	2,811	2,531	2,251	1,971	2,251	1,410	1,130
26	7,009	6,533	6,100	5,725	5,350	4,975	4,601	4,226	3,851	4,324	3,101	2,727
27	7,200	6,700	6,245	5,835	5,425	5,015	4,605	4,195	3,785	4,249	2,964	2,554
29	9,507	8,995	8,529	8,104	7,679	7,253	6,828	6,403	5,978	6,662	5,128	4,703
46	1,778	1,788	1,797	1,965	2,135	2,304	2,474	2,643	2,813	3,157	3,151	3,321
47	780	798	814	994	1,175	1,356	1,536	1,717	1,898	2,151	2,259	2,440
Customer Rate Impact, Dollars per MWh (2009$)												
1	4.00	4.38	4.73	5.09	5.46	5.82	6.19	6.56	6.92	7.57	7.66	8.02
2	4.05	4.43	4.77	5.13	5.49	5.85	6.21	6.56	6.92	7.57	7.64	8.00
3	4.54	4.88	5.19	5.51	5.82	6.13	6.44	6.76	7.07	7.73	7.69	8.01
5	4.03	4.37	4.69	5.02	5.35	5.68	6.00	6.33	6.66	7.29	7.32	7.65
8	4.14	4.48	4.79	5.11	5.43	5.75	6.07	6.39	6.71	7.34	7.35	7.67
9	4.01	4.35	4.67	5.00	5.33	5.66	5.99	6.32	6.65	7.27	7.30	7.63
10	4.28	4.62	4.93	5.25	5.57	5.89	6.21	6.53	6.85	7.49	7.49	7.81
11	4.32	4.64	4.93	5.21	5.50	5.79	6.08	6.37	6.65	7.28	7.23	7.52
14	5.07	5.38	5.67	5.96	6.24	6.53	6.81	7.10	7.38	8.08	7.96	8.24
17	4.41	4.72	4.99	5.27	5.54	5.82	6.10	6.38	6.65	7.28	7.21	7.49
18	4.56	4.87	5.15	5.44	5.72	6.01	6.29	6.58	6.87	7.51	7.44	7.72
19	4.60	4.91	5.18	5.46	5.74	6.03	6.31	6.59	6.87	7.52	7.43	7.71
20	5.05	5.31	5.55	5.78	6.02	6.25	6.48	6.72	6.95	7.61	7.42	7.65
22	5.64	5.91	6.17	6.41	6.66	6.90	7.15	7.39	7.64	8.36	8.13	8.38
24	6.00	6.25	6.48	6.71	6.93	7.15	7.38	7.60	7.83	8.57	8.27	8.50
25	4.84	5.13	5.39	5.66	5.92	6.18	6.44	6.71	6.97	7.63	7.50	7.76
26	5.88	6.13	6.36	6.59	6.82	7.05	7.28	7.51	7.74	8.47	8.19	8.42
27	5.74	5.98	6.20	6.41	6.63	6.84	7.05	7.27	7.48	8.19	7.91	8.12
29	6.47	6.72	6.95	7.16	7.38	7.60	7.82	8.04	8.25	9.04	8.69	8.91
46	4.31	4.69	5.02	5.38	5.73	6.08	6.44	6.79	7.14	7.81	7.85	8.20
47	4.15	4.52	4.86	5.21	5.57	5.92	6.28	6.63	6.99	7.64	7.70	8.05
Upper-tail Mean PVRR, Million Dollars (2009$)												
1	65,144	67,632	69,883	72,746	75,620	78,495	81,369	84,243	87,118	95,741	92,866	95,741
2	58,812	61,294	63,542	66,332	69,134	71,935	74,736	77,537	80,338	88,256	85,941	88,742
3	51,373	53,739	55,883	58,419	60,964	63,509	66,055	68,600	71,146	78,099	76,236	78,782
5	60,337	62,706	64,850	67,535	70,231	72,927	75,623	78,319	81,016	89,016	86,408	89,104
8	56,895	59,185	61,259	63,809	66,369	68,929	71,490	74,050	76,610	84,155	81,731	84,291
9	60,620	62,983	65,122	67,802	70,493	73,183	75,874	78,565	81,256	89,281	86,638	89,329
10	59,030	61,205	63,174	65,694	68,225	70,756	73,287	75,819	78,350	86,114	83,412	85,943
11	51,781	54,099	56,200	58,681	61,172	63,662	66,153	68,644	71,135	78,089	76,116	78,607
14	51,809	54,091	56,159	58,561	60,974	63,386	65,798	68,210	70,622	77,512	75,446	77,859
17	55,938	58,085	60,028	62,399	64,780	67,161	69,542	71,922	74,303	81,616	79,064	81,445
18	56,883	59,050	61,013	63,422	65,841	68,260	70,679	73,098	75,517	82,957	80,355	82,775
19	56,912	59,053	60,992	63,367	65,752	8,137	70,522	72,907	75,292	82,709	80,062	82,448
20	53,336	55,469	57,401	59,677	61,963	64,249	66,535	68,821	71,107	78,070	75,679	77,965
22	52,314	54,504	56,487	58,758	61,039	63,319	65,599	67,879	70,159	76,996	74,719	76,999
24	53,427	55,521	57,417	59,616	61,824	64,032	66,240	68,448	70,656	77,562	75,072	77,281
25	54,523	56,606	58,492	60,786	63,089	65,393	67,696	70,000	72,303	79,418	76,910	79,214
26	54,074	56,181	58,089	60,327	62,573	64,820	67,067	69,313	71,560	78,565	76,053	78,300

Case	Expected Value CO2 Tax ($/ton)											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
27	53,182	55,277	57,174	59,374	61,582	63,791	66,000	68,209	70,417	77,299	74,835	77,044
29	55,173	57,264	59,158	61,330	63,512	65,693	67,875	70,057	72,238	79,293	76,601	78,783
46	59,779	62,233	64,455	67,209	69,973	72,738	75,502	78,267	81,032	89,019	86,561	89,326
47	59,158	61,626	63,860	66,634	69,419	72,203	74,988	77,773	80,557	88,498	86,127	88,912
Standard Deviation of Production Costs, Million Dollars (2009$)												
1	11,320	11,591	11,837	12,259	12,683	13,107	13,531	13,955	14,379	15,852	15,227	15,651
2	9,650	9,929	10,181	10,601	11,023	11,445	11,867	12,289	12,711	14,012	13,555	13,977
3	7,287	7,548	7,784	8,165	8,547	8,929	9,311	9,694	10,076	11,106	10,840	11,223
5	9,911	10,186	10,434	10,850	11,268	11,685	12,103	12,521	12,938	14,263	13,774	14,192
8	8,916	9,188	9,433	9,835	10,239	10,642	11,046	11,450	11,853	13,065	12,661	13,064
9	9,941	10,213	10,459	10,873	11,288	11,704	12,119	12,534	12,950	14,276	13,781	14,196
10	9,294	9,535	9,753	10,145	10,539	10,932	11,326	11,719	12,113	13,362	12,900	13,294
11	7,274	7,526	7,754	8,126	8,499	8,872	9,244	9,617	9,990	11,013	10,736	11,109
14	6,837	7,075	7,290	7,643	7,998	8,353	8,708	9,063	9,418	10,383	10,128	10,483
17	8,241	8,502	8,738	9,121	9,506	9,891	10,276	10,661	11,045	12,174	11,815	12,200
18	8,463	8,726	8,964	9,352	9,741	10,130	10,520	10,909	11,298	12,453	12,077	12,466
19	8,362	8,621	8,855	9,237	9,620	10,004	10,388	10,771	11,155	12,295	11,922	12,306
20	7,058	7,293	7,505	7,850	8,196	8,542	8,888	9,234	9,580	10,559	10,272	10,618
22	6,538	6,758	6,958	7,286	7,616	7,946	8,276	8,606	8,936	9,852	9,596	9,926
24	6,602	6,828	7,033	7,363	7,695	8,026	8,357	8,689	9,020	9,942	9,682	10,014
25	7,567	7,814	8,038	8,400	8,764	9,129	9,493	9,857	10,221	11,266	10,949	11,313
26	6,810	7,043	7,254	7,592	7,931	8,271	8,610	8,949	9,289	10,237	9,967	10,307
27	6,578	6,801	7,003	7,329	7,656	7,983	8,310	8,637	8,964	9,880	9,618	9,945
29	6,575	6,787	6,980	7,294	7,611	7,927	8,243	8,559	8,875	9,783	9,507	9,823
46	9,483	9,761	10,012	10,431	10,851	11,271	11,691	12,111	12,531	13,814	13,371	13,791
47	9,573	9,854	10,108	10,531	10,955	11,379	11,803	12,227	12,651	13,945	13,499	13,923

Table B.10 – Stochastic Cost Results based on Probability-weighted CO_2 Tax Levels

Case	Expected Value CO2 Tax											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
Risk-adjusted PVRR, Weighted Averages, Million Dollars (2009$)												
2B	30,457	32,553	34,459	36,501	38,550	40,599	42,649	44,698	46,747	48,796	50,845	52,896
5B	30,558	32,534	34,330	36,256	38,188	40,120	42,052	43,985	45,917	47,849	49,781	51,716
5B_CCCT Dry	30,446	32,422	34,219	36,154	38,095	40,037	41,978	43,920	45,861	47,803	49,744	51,688
5B_CCCT Wet	30,420	32,390	34,181	36,111	38,046	39,982	41,917	43,853	45,789	47,724	49,660	51,598
8B	31,177	33,081	34,811	36,648	38,491	40,334	42,177	44,020	45,863	47,707	49,550	51,395
9B	30,814	32,795	34,596	36,530	38,470	40,409	42,349	44,289	46,229	48,168	50,108	52,051
10B	31,763	33,675	35,413	37,262	39,116	40,971	42,826	44,681	46,536	48,391	50,246	52,103
17B	32,917	34,671	36,265	37,934	39,610	41,286	42,962	44,638	46,314	47,990	49,666	51,344
18B	32,564	34,350	35,974	37,686	39,405	41,123	42,841	44,560	46,278	47,996	49,715	51,436
47B	30,966	33,053	34,949	36,986	39,030	41,074	43,118	45,161	47,205	49,249	51,293	53,339
Cost Exposure for CO2 Tax Scenarios, Million Dollars (2009$)												
2B	270	357	437	634	831	1,028	1,225	1,422	1,619	1,816	2,014	2,211
5B	371	338	308	388	468	548	629	709	790	870	950	1,031
5B_CCCT Dry	259	226	196	286	376	465	555	644	734	824	913	1,003

Case	Expected Value CO2 Tax											
	$15	$20	$25	$30	$35	$40	$45	$50	$55	$60	$65	$70
5B_CCCT Wet	233	194	159	243	326	410	494	578	661	745	829	913
8B	990	885	789	780	772	763	754	745	736	727	718	710
9B	627	599	574	662	750	838	926	1,013	1,101	1,189	1,277	1,365
10B	1,576	1,479	1,391	1,394	1,397	1,400	1,403	1,406	1,409	1,412	1,415	1,418
17B	2,730	2,475	2,243	2,067	1,891	1,715	1,539	1,363	1,187	1,011	835	659
18B	2,377	2,155	1,952	1,818	1,685	1,551	1,418	1,284	1,151	1,017	884	750
47B	780	857	927	1,118	1,310	1,502	1,694	1,886	2,078	2,270	2,462	2,654
Customer Rate Impact, Dollars per MWh (2009$)												
2B	4.16	4.54	4.88	5.24	5.59	5.95	6.30	6.66	7.02	7.37	7.73	8.09
5B	4.13	4.48	4.80	5.14	5.47	5.81	6.14	6.48	6.81	7.15	7.49	7.82
5B_CCCT Dry	4.13	4.48	4.80	5.13	5.46	5.79	6.11	6.44	6.77	7.10	7.43	7.76
5B_CCCT Wet	4.12	4.47	4.78	5.11	5.44	5.77	6.10	6.43	6.75	7.08	7.41	7.74
8B	4.26	4.60	4.91	5.23	5.55	5.87	6.20	6.52	6.84	7.16	7.48	7.80
9B	4.11	4.47	4.79	5.12	5.46	5.80	6.13	6.47	6.80	7.14	7.47	7.81
10B	4.38	4.73	5.04	5.36	5.69	6.01	6.33	6.66	6.98	7.30	7.63	7.95
17B	4.61	4.91	5.19	5.47	5.75	6.02	6.30	6.58	6.86	7.14	7.42	7.70
18B	4.55	4.86	5.14	5.42	5.71	6.00	6.28	6.57	6.85	7.14	7.43	7.71
47B	4.20	4.57	4.91	5.26	5.61	5.96	6.31	6.66	7.01	7.37	7.72	8.07
Upper-tail Mean PVRR, Dollars per MWh (2009$)												
2B	58,307	60,787	63,042	65,810	68,589	71,368	74,147	76,926	79,705	82,484	85,263	88,047
5B	59,065	61,417	63,556	66,203	68,859	71,516	74,173	76,830	79,486	82,143	84,800	87,462
5B_CCCT Dry	60,232	62,570	64,696	67,356	70,027	72,698	75,369	78,040	80,710	83,381	86,052	88,728
5B_CCCT Wet	60,077	62,404	64,520	67,173	69,836	72,500	75,163	77,827	80,490	83,154	85,817	88,486
8B	57,266	59,548	61,622	64,161	66,709	69,258	71,807	74,356	76,904	79,453	82,002	84,556
9B	59,723	62,080	64,224	66,878	69,543	72,207	74,872	77,537	80,202	82,867	85,532	88,202
10B	58,358	60,657	62,747	65,313	67,889	70,465	73,042	75,618	78,194	80,770	83,346	85,928
17B	55,940	58,075	60,016	62,370	64,733	67,096	69,459	71,822	74,185	76,548	78,911	81,279
18B	57,128	59,293	61,262	63,669	66,086	68,504	70,921	73,338	75,755	78,172	80,589	83,012
47B	59,003	61,471	63,714	66,486	69,268	72,050	74,832	77,615	80,397	83,179	85,961	88,748
Standard Deviation of Production Costs, Million Dollars (2009$)												
2B	9,524	9,789	10,030	10,433	10,837	11,242	11,646	12,051	12,455	12,860	13,264	13,670
5B	9,660	9,919	10,154	10,550	10,948	11,346	11,744	12,142	12,540	12,938	13,336	13,735
5B_CCCT Dry	9,937	10,195	10,429	10,829	11,232	11,634	12,036	12,439	12,841	13,243	13,645	14,049
5B_CCCT Wet	9,897	10,154	10,387	10,787	11,189	11,591	11,992	12,394	12,796	13,198	13,600	14,003
8B	9,059	9,315	9,548	9,935	10,323	10,712	11,101	11,489	11,878	12,266	12,655	13,044
9B	9,755	10,013	10,248	10,644	11,042	11,440	11,838	12,236	12,634	13,031	13,429	13,828
10B	9,158	9,418	9,655	10,049	10,444	10,839	11,234	11,629	12,024	12,419	12,814	13,209
17B	8,347	8,593	8,818	9,186	9,557	9,927	10,297	10,668	11,038	11,409	11,779	12,150
18B	8,680	8,930	9,157	9,533	9,910	10,287	10,665	11,042	11,420	11,797	12,174	12,553
47B	9,564	9,831	10,074	10,482	10,893	11,303	11,713	12,123	12,533	12,944	13,354	13,765

PORTFOLIO MEASURE RANKINGS AND PREFERENCE SCORES

Tables (B.11 through B.22) display the portfolio measure ranking and preference scores based on probability-weighted CO_2 tax levels from $15/ton to $70/ton at $5 increments (The two non-cost-based measures, average annual ENS and LOLP, are not probability-weighted.) Tables are shown for the original 21 portfolios and the additional 10 portfolios developed to determine the 2012 gas resource deferral strategy associated with the termination of the Lake Side 2 combined-cycle plant construction contract ("B" series portfolios).

Table B.23 shows portfolio measure ranking and preference scores for the additional 10 gas resource deferral strategy portfolios given an alternate importance weighting scheme with the following characteristics:

- The mean PVRR substitutes for the risk-adjusted PVRR measure
- The mean upper-tail PVRR risk measure is added
- The mean PVRR and upper-tail PVRR measures are given importance weights of 25% and 20% respectively (importance weights for all other measures remain unchanged)

The purpose of this alternative ranking scheme is to show the portfolio performance impact of heavily weighting upper-tail risk as a separate measure.

Table B.11 – $15/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	1.5	1.0	1.0	1.5	10.0	10.0	10	**2.7**	**2.4**
2	1.0	1.2	1.3	1.0	6.9	3.9	2.1	**1.5**	**1.0**
3	3.3	3.0	6.7	3.3	2.4	2.0	2.1	**3.2**	**3.1**
5	1.5	1.1	1.6	1.5	7.3	5.2	4.6	**2.0**	**1.6**
8	1.8	1.5	4.3	1.8	5.5	5.1	7.6	**2.5**	**2.2**
9	1.6	1.0	1.8	1.6	7.4	5.9	5.8	**2.2**	**1.8**
10	2.5	2.0	3.8	2.5	6.2	5.5	8.9	**3.1**	**3.0**
11	4.0	2.2	7.1	4.0	2.4	2.2	2.9	**3.5**	**3.5**
14	5.7	4.9	9.7	5.7	1.6	1.4	1.3	**5.1**	**5.5**
17	3.5	2.5	6.6	3.5	4.2	4.2	6.6	**3.7**	**3.7**
18	3.4	3.1	5.4	3.4	4.6	4.4	7.8	**3.8**	**3.8**
19	3.9	3.2	6.4	3.9	4.4	4.4	7.1	**4.1**	**4.2**
20	6.1	4.8	8.0	6.1	2.0	2.1	4.3	**5.4**	**5.9**
22	7.4	7.0	10.0	7.4	1.0	1.0	1.0	**6.5**	**7.2**
24	7.8	8.3	9.6	7.8	1.1	1.1	1.5	**7.0**	**7.9**
25	5.1	4.1	8.0	5.1	2.9	3.1	5.1	**4.8**	**5.1**
26	7.6	7.8	9.6	7.6	1.5	1.5	3.4	**6.9**	**7.8**
27	7.8	7.3	9.6	7.8	1.1	1.3	2.6	**6.9**	**7.7**
29	10.0	10.0	9.7	10.0	1.1	1.0	1.7	**8.7**	**10.0**
46	2.6	2.1	2.7	2.6	6.5	4.8	9.0	**3.1**	**3.0**
47	1.6	1.5	1.5	1.6	6.7	4.5	6.9	**2.3**	**1.9**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
2B	1.1	1.9	1.0	3.0	7.7	1.2	1	**1.5**	**1.2**
5B	1.5	1.2	3.0	4.0	8.4	7.5	6.3	**2.4**	**2.2**
5B_CCCT Dry	1.1	1.4	1.5	2.0	10.0	4.8	4.9	**1.6**	**1.3**
5B_CCCT Wet	1.0	1.2	1.5	1.0	9.8	4.6	4.7	**1.4**	**1.0**
8B	3.7	3.6	6.4	7.0	5.0	4.9	4.5	**4.2**	**4.5**
9B	2.4	1.0	3.2	5.0	9.0	10.0	10.0	**3.2**	**3.3**
10B	5.8	5.9	5.7	8.0	5.6	5.3	6.8	**5.9**	**6.6**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.7	8.9	8.2	9.0	2.9	3.3	2.2	**7.7**	**8.9**
47B	3.0	2.6	1.2	6.0	7.9	1.0	7.4	**3.2**	**3.3**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

Table B.12 – \$20/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1	1.5	1.1	1.0	1.5	10.0	10.0	10	**2.7**	**2.4**
2	1.0	1.3	1.3	1.0	6.9	3.9	2.1	**1.6**	**1.0**
3	3.2	3.0	6.7	3.2	2.5	2.0	2.1	**3.2**	**3.1**
5	1.4	1.1	1.6	1.4	7.4	5.2	4.6	**2.0**	**1.5**
8	1.6	1.5	4.3	1.6	5.5	5.1	7.6	**2.4**	**2.1**
9	1.5	1.0	1.8	1.5	7.4	5.9	5.8	**2.1**	**1.7**
10	2.4	2.0	3.8	2.4	6.2	5.5	8.9	**3.0**	**2.9**
11	3.8	2.1	7.1	3.8	2.4	2.2	2.9	**3.5**	**3.4**
14	5.6	4.9	9.7	5.6	1.6	1.4	1.3	**5.1**	**5.4**
17	3.3	2.4	6.6	3.3	4.2	4.2	6.6	**3.5**	**3.5**
18	3.2	3.0	5.4	3.2	4.7	4.4	7.8	**3.6**	**3.6**
19	3.7	3.1	6.4	3.7	4.5	4.4	7.1	**3.9**	**4.0**
20	5.9	4.6	8.0	5.9	2.0	2.1	4.3	**5.3**	**5.7**
22	7.3	6.9	10.0	7.3	1.0	1.0	1.0	**6.4**	**7.2**
24	7.7	8.2	9.6	7.7	1.1	1.1	1.5	**6.9**	**7.8**
25	4.9	4.0	8.0	4.9	3.0	3.1	5.1	**4.7**	**5.0**
26	7.5	7.8	9.6	7.5	1.5	1.5	3.4	**6.8**	**7.7**
27	7.7	7.2	9.6	7.7	1.1	1.3	2.6	**6.8**	**7.6**
29	10.0	10.0	9.7	10.0	1.1	1.0	1.7	**8.7**	**10.0**
46	2.7	2.3	2.7	2.7	6.6	4.8	9.0	**3.2**	**3.1**
47	1.7	1.6	1.5	1.7	6.8	4.5	6.9	**2.3**	**1.9**

Importance Weights	45%	20%	5%	15%	5%	5%	5%

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	1.6	2.4	1.0	4.0	7.7	1.2	1	**2.0**	**1.8**
5B	1.6	1.3	3.0	3.0	8.5	7.5	6.3	**2.2**	**2.1**
5B_CCCT Dry	1.1	1.3	1.5	2.0	10.0	4.8	4.9	**1.6**	**1.3**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.7	3.7	6.4	7.0	5.1	4.9	4.5	**4.3**	**4.6**
9B	2.6	1.0	3.2	5.0	9.0	10.0	10.0	**3.3**	**3.4**
10B	6.1	6.3	5.7	8.0	5.6	5.3	6.8	**6.1**	**6.8**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.7	8.9	8.2	9.0	2.9	3.3	2.2	**7.7**	**8.9**
47B	3.6	3.1	1.2	6.0	8.0	1.0	7.4	**3.6**	**3.8**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.13 – \$25/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	1.6	1.2	1.0	1.6	10.0	10.0	10	**2.7**	**2.5**
2	1.0	1.4	1.3	1.0	6.9	3.9	2.1	**1.6**	**1.0**
3	3.1	3.1	6.7	3.1	2.5	2.0	2.1	**3.2**	**3.0**
5	1.3	1.1	1.6	1.3	7.4	5.2	4.6	**1.9**	**1.4**
8	1.5	1.5	4.3	1.5	5.6	5.1	7.6	**2.3**	**1.9**
9	1.4	1.0	1.8	1.4	7.5	5.9	5.8	**2.1**	**1.6**
10	2.2	2.0	3.8	2.2	6.2	5.5	8.9	**3.0**	**2.7**
11	3.7	2.0	7.1	3.7	2.5	2.2	2.9	**3.4**	**3.3**
14	5.6	5.0	9.7	5.6	1.6	1.4	1.3	**5.0**	**5.4**
17	3.1	2.3	6.6	3.1	4.3	4.2	6.6	**3.4**	**3.3**
18	3.1	2.9	5.4	3.1	4.7	4.4	7.8	**3.5**	**3.5**
19	3.5	3.0	6.4	3.5	4.5	4.4	7.1	**3.8**	**3.8**
20	5.8	4.5	8.0	5.8	2.0	2.1	4.3	**5.2**	**5.6**
22	7.3	6.9	10.0	7.3	1.0	1.0	1.0	**6.4**	**7.1**
24	7.6	8.2	9.6	7.6	1.1	1.1	1.5	**6.8**	**7.7**
25	4.7	3.9	8.0	4.7	3.0	3.1	5.1	**4.6**	**4.8**
26	7.4	7.7	9.6	7.4	1.5	1.5	3.4	**6.8**	**7.6**
27	7.5	7.0	9.6	7.5	1.1	1.3	2.6	**6.7**	**7.4**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	2.7	2.4	2.7	2.7	6.6	4.8	9.0	**3.3**	**3.1**
47	1.7	1.8	1.5	1.7	6.8	4.5	6.9	**2.3**	**1.9**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	2.2	3.2	1.0	4.0	7.8	1.2	1	**2.4**	**2.3**
5B	1.6	1.4	3.0	3.0	8.5	7.5	6.3	**2.3**	**2.2**
5B_CCCT Dry	1.2	1.3	1.5	2.0	10.0	4.8	4.9	**1.6**	**1.4**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.7	3.8	6.4	6.0	5.1	4.9	4.5	**4.1**	**4.4**
9B	2.8	1.1	3.2	5.0	9.0	10.0	10.0	**3.4**	**3.5**
10B	6.3	6.7	5.7	8.0	5.7	5.3	6.8	**6.3**	**7.1**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.7	8.9	8.2	9.0	2.9	3.3	2.2	**7.7**	**8.9**
47B	4.3	3.8	1.2	7.0	8.0	1.0	7.4	**4.2**	**4.5**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.14 – $30/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	1.7	1.4	1.0	1.7	10.0	10.0	10	**2.8**	**2.6**
2	1.0	1.5	1.3	1.0	7.0	3.9	2.1	**1.6**	**1.0**
3	3.0	3.1	6.7	3.0	2.6	2.0	2.1	**3.1**	**2.9**
5	1.2	1.1	1.6	1.2	7.4	5.2	4.6	**1.9**	**1.3**
8	1.3	1.5	4.3	1.3	5.6	5.1	7.6	**2.2**	**1.7**
9	1.3	1.0	1.8	1.3	7.5	5.9	5.8	**2.0**	**1.5**
10	2.1	2.0	3.8	2.1	6.2	5.5	8.9	**2.9**	**2.6**
11	3.6	1.9	7.1	3.6	2.5	2.2	2.9	**3.2**	**3.1**
14	5.4	5.0	9.7	5.4	1.6	1.4	1.3	**5.0**	**5.3**
17	2.8	2.1	6.6	2.8	4.3	4.2	6.6	**3.2**	**3.0**
18	2.8	2.8	5.4	2.8	4.7	4.4	7.8	**3.4**	**3.2**
19	3.3	2.9	6.4	3.3	4.5	4.4	7.1	**3.7**	**3.6**
20	5.5	4.3	8.0	5.5	2.0	2.1	4.3	**5.0**	**5.3**
22	7.2	6.9	10.0	7.2	1.0	1.0	1.0	**6.3**	**7.0**
24	7.4	8.1	9.6	7.4	1.1	1.1	1.5	**6.7**	**7.5**
25	4.5	3.7	8.0	4.5	3.0	3.1	5.1	**4.4**	**4.5**
26	7.2	7.6	9.6	7.2	1.6	1.5	3.4	**6.7**	**7.4**
27	7.4	6.9	9.6	7.4	1.1	1.3	2.6	**6.5**	**7.2**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	2.8	2.6	2.7	2.8	6.7	4.8	9.0	**3.4**	**3.2**
47	1.7	1.9	1.5	1.7	6.9	4.5	6.9	**2.4**	**2.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			**Risk Measures**					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	2.9	4.2	1.0	4.0	7.8	1.2	1	**2.9**	**2.9**
5B	1.7	1.6	3.0	3.0	8.5	7.5	6.3	**2.4**	**2.3**
5B_CCCT Dry	1.2	1.4	1.5	2.0	10.0	4.8	4.9	**1.7**	**1.4**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.7	4.0	6.4	6.0	5.1	4.9	4.5	**4.1**	**4.4**
9B	3.1	1.3	3.2	5.0	9.0	10.0	10.0	**3.6**	**3.7**
10B	6.7	7.4	5.7	8.0	5.7	5.3	6.8	**6.6**	**7.4**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.8	8.9	8.2	9.0	2.9	3.3	2.2	**7.8**	**8.9**
47B	5.3	4.7	1.2	7.0	8.1	1.0	7.4	**4.9**	**5.3**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.15 – \$35/ton Expected-value CO_2 Tax

	Cost Measures			**Risk Measures**					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	1.8	1.6	1.0	1.8	10.0	10.0	10	**3.0**	**2.7**
2	1.0	1.7	1.3	1.0	7.1	3.9	2.1	**1.7**	**1.0**
3	2.8	3.1	6.7	2.8	2.7	2.0	2.1	**3.0**	**2.7**
5	1.0	1.1	1.6	1.0	7.5	5.2	4.6	**1.8**	**1.2**
8	1.0	1.4	4.3	1.0	5.7	5.1	7.6	**2.0**	**1.5**
9	1.2	1.0	1.8	1.2	7.5	5.9	5.8	**2.0**	**1.4**
10	1.9	2.1	3.8	1.9	6.2	5.5	8.9	**2.8**	**2.5**
11	3.3	1.8	7.1	3.3	2.6	2.2	2.9	**3.1**	**2.8**
14	5.3	5.0	9.7	5.3	1.7	1.4	1.3	**4.9**	**5.1**
17	2.5	1.9	6.6	2.5	4.4	4.2	6.6	**3.0**	**2.7**
18	2.5	2.7	5.4	2.5	4.8	4.4	7.8	**3.2**	**3.0**
19	3.0	2.8	6.4	3.0	4.6	4.4	7.1	**3.5**	**3.4**
20	5.3	4.0	8.0	5.3	2.0	2.1	4.3	**4.8**	**5.0**
22	7.0	6.8	10.0	7.0	1.0	1.0	1.0	**6.2**	**6.9**
24	7.2	8.0	9.6	7.2	1.1	1.1	1.5	**6.6**	**7.3**
25	4.2	3.6	8.0	4.2	3.0	3.1	5.1	**4.2**	**4.2**
26	7.0	7.5	9.6	7.0	1.6	1.5	3.4	**6.5**	**7.3**
27	7.1	6.7	9.6	7.1	1.1	1.3	2.6	**6.3**	**7.0**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.0	2.8	2.7	3.0	6.7	4.8	9.0	**3.5**	**3.3**
47	1.7	2.1	1.5	1.7	6.9	4.5	6.9	**2.4**	**2.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	3.9	5.5	1.0	6.0	7.9	1.2	1	**3.9**	**4.2**
5B	1.8	1.9	3.0	3.0	8.5	7.5	6.3	**2.5**	**2.4**
5B_CCCT Dry	1.3	1.4	1.5	2.0	10.0	4.8	4.9	**1.7**	**1.5**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.6	4.3	6.4	5.0	5.1	4.9	4.5	**4.0**	**4.3**
9B	3.4	1.6	3.2	4.0	9.0	10.0	10.0	**3.6**	**3.8**
10B	7.2	8.3	5.7	8.0	5.8	5.3	6.8	**7.0**	**7.9**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.8	9.0	8.2	9.0	2.9	3.3	2.2	**7.8**	**8.9**
47B	6.7	6.0	1.2	7.0	8.2	1.0	7.4	**5.7**	**6.4**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.16 – \$40/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	2.2	1.8	1.0	2.2	10.0	10.0	10	**3.2**	**2.8**
2	1.3	1.9	1.3	1.3	7.1	3.9	2.1	**1.9**	**1.0**
3	2.8	3.2	6.7	2.8	2.7	2.0	2.1	**3.0**	**2.5**
5	1.2	1.1	1.6	1.2	7.5	5.2	4.6	**1.9**	**1.0**
8	1.0	1.4	4.3	1.0	5.7	5.1	7.6	**2.0**	**1.2**
9	1.3	1.0	1.8	1.3	7.6	5.9	5.8	**2.1**	**1.3**
10	2.0	2.1	3.8	2.0	6.2	5.5	8.9	**2.8**	**2.3**
11	3.3	1.6	7.1	3.3	2.6	2.2	2.9	**3.0**	**2.6**
14	5.3	5.0	9.7	5.3	1.7	1.4	1.3	**4.9**	**5.0**
17	2.3	1.8	6.6	2.3	4.4	4.2	6.6	**2.8**	**2.3**
18	2.4	2.6	5.4	2.4	4.8	4.4	7.8	**3.1**	**2.6**
19	2.9	2.7	6.4	2.9	4.6	4.4	7.1	**3.4**	**3.0**
20	5.1	3.7	8.0	5.1	2.1	2.1	4.3	**4.6**	**4.6**
22	6.9	6.8	10.0	6.9	1.0	1.0	1.0	**6.2**	**6.7**
24	7.0	7.9	9.6	7.0	1.2	1.1	1.5	**6.5**	**7.1**
25	4.0	3.4	8.0	4.0	3.1	3.1	5.1	**4.0**	**3.9**
26	6.9	7.5	9.6	6.9	1.6	1.5	3.4	**6.4**	**7.1**
27	7.0	6.5	9.6	7.0	1.1	1.3	2.6	**6.2**	**6.7**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.3	3.0	2.7	3.3	6.8	4.8	9.0	**3.7**	**3.5**
47	2.0	2.2	1.5	2.0	7.0	4.5	6.9	**2.7**	**2.1**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	5.3	7.3	1.0	6.0	7.9	1.2	1	**4.9**	**5.4**
5B	2.0	2.4	3.0	3.0	8.5	7.5	6.3	**2.6**	**2.6**
5B_CCCT Dry	1.4	1.6	1.5	2.0	10.0	4.8	4.9	**1.8**	**1.6**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	3.4	4.7	6.4	4.0	5.1	4.9	4.5	**3.9**	**4.1**
9B	3.9	1.9	3.2	5.0	9.0	10.0	10.0	**4.1**	**4.4**
10B	7.8	9.5	5.7	7.0	5.8	5.3	6.8	**7.4**	**8.4**
17B	10.0	10.0	10.0	10.0	1.0	1.1	2.2	**8.7**	**10.0**
18B	8.9	9.0	8.2	9.0	2.9	3.3	2.2	**7.8**	**9.0**
47B	8.5	7.8	1.2	8.0	8.3	1.0	7.4	**7.1**	**8.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.17 – $45/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	2.7	2.0	1.0	2.7	10.0	10.0	10	**3.6**	**3.2**
2	1.6	2.1	1.3	1.6	7.2	3.9	2.1	**2.1**	**1.2**
3	2.8	3.2	6.7	2.8	2.8	2.0	2.1	**3.0**	**2.4**
5	1.3	1.1	1.6	1.3	7.6	5.2	4.6	**2.0**	**1.0**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**2.0**	**1.1**
9	1.5	1.0	1.8	1.5	7.6	5.9	5.8	**2.2**	**1.3**
10	2.1	2.1	3.8	2.1	6.2	5.5	8.9	**2.9**	**2.2**
11	3.3	1.4	7.1	3.3	2.7	2.2	2.9	**3.0**	**2.4**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.9**	**4.9**
17	2.2	1.5	6.6	2.2	4.5	4.2	6.6	**2.7**	**2.0**
18	2.3	2.5	5.4	2.3	4.9	4.4	7.8	**3.0**	**2.4**
19	2.8	2.6	6.4	2.8	4.7	4.4	7.1	**3.3**	**2.8**
20	4.9	3.4	8.0	4.9	2.1	2.1	4.3	**4.4**	**4.3**
22	6.9	6.7	10.0	6.9	1.1	1.0	1.0	**6.1**	**6.6**
24	6.8	7.8	9.6	6.8	1.2	1.1	1.5	**6.3**	**6.9**
25	3.8	3.3	8.0	3.8	3.1	3.1	5.1	**3.9**	**3.6**
26	6.8	7.4	9.6	6.8	1.6	1.5	3.4	**6.4**	**6.9**
27	6.8	6.2	9.6	6.8	1.1	1.3	2.6	**6.1**	**6.5**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	3.7	3.2	2.7	3.7	6.9	4.8	9.0	**4.1**	**3.8**
47	2.4	2.4	1.5	2.4	7.1	4.5	6.9	**2.9**	**2.3**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	6.5	8.9	1.0	6.0	8.0	1.2	1	**5.8**	**6.7**
5B	2.0	2.7	3.0	3.0	8.5	7.5	6.3	**2.7**	**2.8**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.8**	**1.7**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	2.9	4.8	6.4	4.0	5.2	4.9	4.5	**3.7**	**4.0**
9B	4.2	2.3	3.2	5.0	9.0	10.0	10.0	**4.3**	**4.8**
10B	7.8	10.0	5.7	7.0	5.8	5.3	6.8	**7.5**	**8.9**
17B	8.8	8.9	10.0	9.0	1.0	1.1	2.2	**7.8**	**9.3**
18B	7.9	8.1	8.2	8.0	2.9	3.3	2.2	**7.1**	**8.4**
47B	10.0	9.2	1.2	10.0	8.3	1.0	7.4	**8.3**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.18 – $50/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1	3.2	2.3	1.0	3.2	10.0	10.0	10	**3.9**	**3.6**
2	2.0	2.3	1.3	2.0	7.2	3.9	2.1	**2.4**	**1.5**
3	2.8	3.3	6.7	2.8	2.9	2.0	2.1	**3.0**	**2.4**
5	1.5	1.1	1.6	1.5	7.6	5.2	4.6	**2.1**	**1.1**
8	1.0	1.4	4.3	1.0	5.8	5.1	7.6	**2.0**	**1.0**
9	1.7	1.0	1.8	1.7	7.6	5.9	5.8	**2.3**	**1.4**
10	2.2	2.1	3.8	2.2	6.3	5.5	8.9	**2.9**	**2.3**
11	3.2	1.3	7.1	3.2	2.8	2.2	2.9	**2.9**	**2.3**
14	5.3	5.1	9.7	5.3	1.8	1.4	1.3	**4.9**	**4.9**
17	2.0	1.3	6.6	2.0	4.5	4.2	6.6	**2.6**	**1.8**
18	2.2	2.4	5.4	2.2	4.9	4.4	7.8	**2.9**	**2.3**
19	2.7	2.4	6.4	2.7	4.7	4.4	7.1	**3.2**	**2.6**
20	4.7	3.1	8.0	4.7	2.1	2.1	4.3	**4.2**	**4.0**
22	6.8	6.6	10.0	6.8	1.1	1.0	1.0	**6.1**	**6.5**
24	6.6	7.7	9.6	6.6	1.2	1.1	1.5	**6.2**	**6.7**
25	3.6	3.0	8.0	3.6	3.2	3.1	5.1	**3.7**	**3.3**
26	6.6	7.2	9.6	6.6	1.7	1.5	3.4	**6.2**	**6.7**
27	6.6	6.0	9.6	6.6	1.1	1.3	2.6	**5.9**	**6.2**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	4.2	3.5	2.7	4.2	6.9	4.8	9.0	**4.4**	**4.2**
47	2.8	2.7	1.5	2.8	7.1	4.5	6.9	**3.2**	**2.6**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
2B	6.8	9.9	1.0	9.0	8.0	1.2	1	**6.5**	**7.6**
5B	1.9	3.0	3.0	3.0	8.5	7.5	6.3	**2.7**	**2.8**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.9**	**1.7**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	2.2	4.5	6.4	4.0	5.2	4.9	4.5	**3.3**	**3.4**
9B	4.0	2.5	3.2	5.0	9.0	10.0	10.0	**4.2**	**4.6**
10B	6.7	9.7	5.7	8.0	5.9	5.3	6.8	**7.1**	**8.2**
17B	6.4	6.9	10.0	7.0	1.0	1.1	2.2	**6.0**	**6.9**
18B	5.9	6.4	8.2	6.0	2.9	3.3	2.2	**5.5**	**6.2**
47B	10.0	10.0	1.2	10.0	8.4	1.0	7.4	**8.5**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.19 – $55/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
1	3.8	2.6	1.0	3.8	10.0	10.0	10	**4.4**	**4.2**
2	2.4	2.6	1.3	2.4	7.3	3.9	2.1	**2.7**	**1.9**
3	2.9	3.4	6.7	2.9	3.0	2.0	2.1	**3.1**	**2.4**
5	1.7	1.1	1.6	1.7	7.6	5.2	4.6	**2.2**	**1.3**
8	1.0	1.4	4.3	1.0	5.9	5.1	7.6	**2.0**	**1.0**
9	1.9	1.0	1.8	1.9	7.7	5.9	5.8	**2.4**	**1.5**
10	2.3	2.1	3.8	2.3	6.3	5.5	8.9	**3.0**	**2.4**
11	3.2	1.0	7.1	3.2	2.8	2.2	2.9	**2.9**	**2.2**
14	5.2	5.1	9.7	5.2	1.9	1.4	1.3	**4.9**	**4.9**
17	1.8	1.0	6.6	1.8	4.5	4.2	6.6	**2.4**	**1.5**
18	2.1	2.2	5.4	2.1	5.0	4.4	7.8	**2.8**	**2.1**
19	2.6	2.3	6.4	2.6	4.7	4.4	7.1	**3.1**	**2.5**
20	4.4	2.7	8.0	4.4	2.2	2.1	4.3	**4.0**	**3.7**
22	6.7	6.6	10.0	6.7	1.1	1.0	1.0	**6.0**	**6.4**
24	6.4	7.6	9.6	6.4	1.2	1.1	1.5	**6.0**	**6.4**
25	3.4	2.8	8.0	3.4	3.2	3.1	5.1	**3.6**	**3.1**
26	6.5	7.1	9.6	6.5	1.7	1.5	3.4	**6.1**	**6.5**
27	6.4	5.7	9.6	6.4	1.1	1.3	2.6	**5.7**	**6.0**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	4.8	3.8	2.7	4.8	7.0	4.8	9.0	**4.8**	**4.8**
47	3.2	2.9	1.5	3.2	7.2	4.5	6.9	**3.5**	**3.1**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh	Weighted Rankings	Normalized Scores (1 to 10)
2B	7.1	10.0	1.0	9.0	8.1	1.2	1	**6.7**	**7.8**
5B	1.8	3.0	3.0	4.0	8.5	7.5	6.3	**2.9**	**2.9**
5B_CCCT Dry	1.5	1.7	1.5	2.0	10.0	4.8	4.9	**1.9**	**1.6**
5B_CCCT Wet	1.0	1.0	1.5	1.0	9.8	4.6	4.7	**1.3**	**1.0**
8B	1.5	3.9	6.4	3.0	5.2	4.9	4.5	**2.7**	**2.7**
9B	3.8	2.6	3.2	5.0	9.0	10.0	10.0	**4.1**	**4.5**
10B	5.7	8.7	5.7	8.0	5.9	5.3	6.8	**6.4**	**7.4**
17B	4.3	4.7	10.0	7.0	1.0	1.1	2.2	**4.6**	**5.1**
18B	4.1	4.4	8.2	6.0	2.9	3.3	2.2	**4.3**	**4.8**
47B	10.0	9.9	1.2	10.0	8.5	1.0	7.4	**8.5**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.20 – $60/ton Expected-value CO_2 Tax

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Ave. for July Event > 25 GWh		
1	4.6	3.1	1.0	4.6	10.0	10.0	10	**4.9**	**4.9**
2	2.9	3.0	1.3	2.9	7.3	3.9	2.1	**3.1**	**2.4**
3	2.9	3.6	6.7	2.9	3.0	2.0	2.1	**3.2**	**2.5**
5	2.0	1.4	1.6	2.0	7.7	5.2	4.6	**2.4**	**1.5**
8	1.0	1.6	4.3	1.0	5.9	5.1	7.6	**2.1**	**1.0**
9	2.2	1.3	1.8	2.2	7.7	5.9	5.8	**2.6**	**1.8**
10	2.4	2.4	3.8	2.4	6.3	5.5	8.9	**3.1**	**2.5**
11	3.2	1.1	7.1	3.2	2.9	2.2	2.9	**2.9**	**2.1**
14	5.2	5.3	9.7	5.2	1.9	1.4	1.3	**4.9**	**4.9**
17	1.6	1.0	6.6	1.6	4.6	4.2	6.6	**2.3**	**1.3**
18	2.0	2.3	5.4	2.0	5.0	4.4	7.8	**2.8**	**2.0**
19	2.4	2.3	6.4	2.4	4.8	4.4	7.1	**3.0**	**2.3**
20	4.1	2.5	8.0	4.1	2.2	2.1	4.3	**3.8**	**3.4**
22	6.6	6.6	10.0	6.6	1.1	1.0	1.0	**5.9**	**6.3**
24	6.1	7.5	9.6	6.1	1.3	1.1	1.5	**5.9**	**6.2**
25	3.1	2.8	8.0	3.1	3.2	3.1	5.1	**3.4**	**2.8**
26	6.3	7.0	9.6	6.3	1.7	1.5	3.4	**6.0**	**6.3**
27	6.1	5.5	9.6	6.1	1.2	1.3	2.6	**5.5**	**5.7**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	5.4	4.3	2.7	5.4	7.0	4.8	9.0	**5.3**	**5.4**
47	3.8	3.4	1.5	3.8	7.2	4.5	6.9	**4.0**	**3.6**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Case	Cost Measures			Risk Measures				Weighted Rankings	Normalized Scores (1 to 10)
	Risk-adjusted PVRR	Rate Impact	Capital Cost	CO2 Cost Exposure	Production Cost Standard Deviation	Ave. Annual Energy Not Served	LOLP, Annual Average for July Event > 25 GWh		
2B	7.4	10.0	1.0	9.0	8.1	1.2	1	**6.8**	**7.9**
5B	1.8	3.1	3.0	4.0	8.5	7.5	6.3	**2.9**	**2.8**
5B_CCCT Dry	1.6	1.6	1.5	3.0	10.0	4.8	4.9	**2.0**	**1.7**
5B_CCCT Wet	1.1	1.0	1.5	2.0	9.8	4.6	4.7	**1.5**	**1.0**
8B	1.0	3.4	6.4	1.0	5.2	4.9	4.5	**2.1**	**1.7**
9B	3.7	2.7	3.2	7.0	9.0	10.0	10.0	**4.4**	**4.8**
10B	5.0	7.8	5.7	8.0	6.0	5.3	6.8	**5.9**	**6.7**
17B	2.7	2.8	10.0	5.0	1.0	1.1	2.2	**3.2**	**3.1**
18B	2.7	2.8	8.2	6.0	2.9	3.3	2.2	**3.4**	**3.4**
47B	10.0	9.8	1.2	10.0	8.5	1.0	7.4	**8.4**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.21 – $65/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	5.4	3.7	1.0	5.4	10.0	10.0	10	**5.5**	**5.7**
2	3.5	3.6	1.3	3.5	7.4	3.9	2.1	**3.6**	**3.0**
3	2.9	3.9	6.7	2.9	3.1	2.0	2.1	**3.2**	**2.6**
5	2.3	1.7	1.6	2.3	7.7	5.2	4.6	**2.7**	**1.8**
8	1.0	1.9	4.3	1.0	6.0	5.1	7.6	**2.1**	**1.0**
9	2.5	1.6	1.8	2.5	7.7	5.9	5.8	**2.9**	**2.1**
10	2.5	2.7	3.8	2.5	6.3	5.5	8.9	**3.3**	**2.6**
11	3.1	1.1	7.1	3.1	2.9	2.2	2.9	**2.8**	**2.0**
14	5.2	5.5	9.7	5.2	2.0	1.4	1.3	**4.9**	**4.9**
17	1.3	1.0	6.6	1.3	4.6	4.2	6.6	**2.1**	**1.0**
18	1.8	2.4	5.4	1.8	5.0	4.4	7.8	**2.7**	**1.8**
19	2.2	2.4	6.4	2.2	4.8	4.4	7.1	**2.9**	**2.2**
20	3.8	2.3	8.0	3.8	2.2	2.1	4.3	**3.6**	**3.0**
22	6.5	6.6	10.0	6.5	1.1	1.0	1.0	**5.9**	**6.1**
24	5.8	7.5	9.6	5.8	1.3	1.1	1.5	**5.7**	**5.9**
25	2.8	2.7	8.0	2.8	3.3	3.1	5.1	**3.2**	**2.5**
26	6.1	7.0	9.6	6.1	1.7	1.5	3.4	**5.8**	**6.1**
27	5.8	5.3	9.6	5.8	1.2	1.3	2.6	**5.3**	**5.3**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	6.2	4.9	2.7	6.2	7.1	4.8	9.0	**5.8**	**6.1**
47	4.4	4.0	1.5	4.4	7.3	4.5	6.9	**4.5**	**4.2**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	7.7	10.0	1.0	9.0	8.2	1.2	1	**7.0**	**8.0**
5B	2.2	3.1	3.0	6.0	8.5	7.5	6.3	**3.3**	**3.2**
5B_CCCT Dry	2.0	1.6	1.5	5.0	10.0	4.8	4.9	**2.5**	**2.1**
5B_CCCT Wet	1.6	1.0	1.5	2.0	9.8	4.6	4.7	**1.7**	**1.0**
8B	1.0	3.0	6.4	1.0	5.2	4.9	4.5	**2.0**	**1.3**
9B	3.9	2.7	3.2	7.0	9.0	10.0	10.0	**4.5**	**4.7**
10B	4.6	7.1	5.7	8.0	6.0	5.3	6.8	**5.6**	**6.2**
17B	1.6	1.3	10.0	3.0	1.0	1.1	2.2	**2.1**	**1.5**
18B	1.9	1.4	8.2	4.0	2.9	3.3	2.2	**2.4**	**1.9**
47B	10.0	9.7	1.2	10.0	8.6	1.0	7.4	**8.4**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.22 – \$70/ton Expected-value CO_2 Tax

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Ave. for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
1	6.4	4.4	1.0	6.4	10.0	10.0	10	**6.3**	**6.8**
2	4.3	4.2	1.3	4.3	7.4	3.9	2.1	**4.1**	**4.0**
3	3.0	4.3	6.7	3.0	3.2	2.0	2.1	**3.3**	**2.9**
5	2.6	2.0	1.6	2.6	7.7	5.2	4.6	**2.9**	**2.4**
8	1.0	2.2	4.3	1.0	6.0	5.1	7.6	**2.2**	**1.4**
9	2.9	1.9	1.8	2.9	7.8	5.9	5.8	**3.2**	**2.7**
10	2.7	3.1	3.8	2.7	6.4	5.5	8.9	**3.5**	**3.1**
11	3.0	1.2	7.1	3.0	3.0	2.2	2.9	**2.8**	**2.2**
14	5.2	5.8	9.7	5.2	2.0	1.4	1.3	**5.0**	**5.1**
17	1.0	1.0	6.6	1.0	4.7	4.2	6.6	**1.9**	**1.0**
18	1.6	2.5	5.4	1.6	5.1	4.4	7.8	**2.6**	**1.9**
19	2.0	2.4	6.4	2.0	4.8	4.4	7.1	**2.8**	**2.2**
20	3.4	2.1	8.0	3.4	2.2	2.1	4.3	**3.3**	**2.8**
22	6.3	6.6	10.0	6.3	1.2	1.0	1.0	**5.8**	**6.1**
24	5.4	7.4	9.6	5.4	1.3	1.1	1.5	**5.4**	**5.7**
25	2.4	2.7	8.0	2.4	3.3	3.1	5.1	**2.9**	**2.4**
26	5.8	6.9	9.6	5.8	1.7	1.5	3.4	**5.7**	**6.0**
27	5.4	5.0	9.6	5.4	1.2	1.3	2.6	**5.0**	**5.1**
29	10.0	10.0	9.7	10.0	1.0	1.0	1.7	**8.7**	**10.0**
46	7.0	5.5	2.7	7.0	7.1	4.8	9.0	**6.5**	**7.1**
47	5.2	4.6	1.5	5.2	7.3	4.5	6.9	**5.0**	**5.1**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

	Cost Measures			Risk Measures					
Case	**Risk-adjusted PVRR**	**Rate Impact**	**Capital Cost**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	8.0	10.0	1.0	9.0	8.2	1.2	1	**7.1**	**8.3**
5B	2.7	3.8	3.0	6.0	8.5	7.5	6.3	**3.7**	**3.9**
5B_CCCT Dry	2.6	2.5	1.5	5.0	10.0	4.8	4.9	**3.0**	**2.9**
5B_CCCT Wet	2.1	1.9	1.5	4.0	9.8	4.6	4.7	**2.5**	**2.3**
8B	1.2	3.4	6.4	2.0	5.2	4.9	4.5	**2.3**	**2.1**
9B	4.2	3.6	3.2	7.0	9.0	10.0	10.0	**4.8**	**5.3**
10B	4.4	6.8	5.7	8.0	6.0	5.3	6.8	**5.5**	**6.2**
17B	1.0	1.0	10.0	1.0	1.0	1.1	2.2	**1.5**	**1.0**
18B	1.4	1.3	8.2	3.0	2.9	3.3	2.2	**2.0**	**1.7**
47B	10.0	9.6	1.2	10.0	8.7	1.0	7.4	**8.4**	**10.0**

Importance Weights	**45%**	**20%**	**5%**	**15%**	**5%**	**5%**	**5%**

Table B.23 – Alternate Performance Ranking Scheme Including the Upper-Tail Mean PVRR

	Cost Measures			Risk Measures						
Case	**Mean PVRR**	**Rate Impact**	**Capital Cost**	**Upper-Tail Mean PVRR**	**CO2 Cost Exposure**	**Production Cost Standard Deviation**	**Ave. Annual Energy Not Served**	**LOLP, Annual Average for July Event > 25 GWh**	**Weighted Rankings**	**Normalized Scores (1 to 10)**
2B	6.0	8.9	1.0	6.0	6.0	8.0	1.2	1	**5.5**	**6.2**
5B	3.0	2.7	3.0	5.0	3.0	8.5	7.5	6.3	**3.6**	**2.3**
5B_CCCT Dry	2.0	1.7	1.5	10.0	2.0	10.0	4.8	4.9	**3.7**	**2.5**
5B_CCCT Wet	1.0	1.0	1.5	9.0	1.0	9.8	4.6	4.7	**2.9**	**1.0**
8B	4.0	4.8	6.4	3.0	4.0	5.2	4.9	4.5	**3.9**	**3.0**
9B	5.0	2.3	3.2	8.0	5.0	9.0	10.0	10.0	**5.2**	**5.5**
10B	7.0	10.0	5.7	4.0	7.0	5.8	5.3	6.8	**6.5**	**8.1**
17B	10.0	8.9	10.0	1.0	9.0	1.0	1.1	2.2	**6.5**	**8.1**
18B	8.0	8.1	8.2	2.0	8.0	2.9	3.3	2.2	**5.9**	**6.9**
47B	9.0	9.2	1.2	7.0	10.0	8.3	1.0	7.4	**7.5**	**10.0**

Importance Weights	**25%**	**20%**	**5%**	**20%**	**15%**	**5%**	**5%**	**5%**

PORTFOLIO PVRR COST COMPONENT COMPARISON

Tables B.24 and B.25 show the breakdown of each portfolio’s stochastic mean PVRR by variable and fixed cost components. These costs reflect the $45/ton CO_2 cost adder scenario. Table B.23 reports the cost component breakdown for the core case risk analysis portfolios, and table B.24 reports the cost component breakdown for the sensitivity cases.

Table B.26 reports the cost component breakdown for the “B-Series” cases.

Table B.24 – Core Case: Portfolio PVRR Cost Components ($45 CO2 - Tax Strategy)

Cost Component ($ 000)	Case 01	Case 02	Case 03	Case 05	Case 08	Case 09	Case 10
Variable Cost							
Total Fuel Cost	16,125,130	15,543,063	13,580,402	15,176,188	14,191,867	15,221,938	14,365,405
Variable O&M Cost	1,354,361	1,313,445	1,178,315	1,299,295	1,222,685	1,301,513	1,231,410
Total Emission Cost	16,572,039	16,423,972	14,513,519	15,372,854	14,691,301	15,402,030	14,814,449
Long Term Contracts and Front Office Transactions	7,683,311	7,645,536	6,218,678	8,279,365	8,978,705	7,043,480	7,898,602
DSM	1,960,939	2,698,475	3,183,577	2,731,677	3,015,434	2,727,382	2,982,268
Spot Market Balancing							
Sales	(11,241,728)	(12,148,264)	(12,685,112)	(12,257,235)	(13,089,333)	(11,693,493)	(12,469,007)
Purchases	5,242,221	4,484,667	3,865,500	4,376,068	3,714,988	4,919,231	4,438,725
Energy Not Served	260,803	160,944	129,235	180,780	184,495	192,675	192,339
Dump Power	(11,314)	(9,874)	(9,475)	(10,424)	(12,366)	(10,539)	(11,477)
Reserve Deficiency	105,557	57,384	42,426	70,640	73,920	84,875	77,276
Total Variable Net Power Costs	**38,051,318**	**36,169,346**	**30,017,065**	**35,219,208**	**32,971,694**	**35,189,092**	**33,519,990**
Real Levelized Fixed Costs	**1,841,501**	**3,372,843**	**10,727,798**	**4,070,089**	**6,272,174**	**4,209,077**	**6,351,579**
Total PVRR	**39,892,819**	**39,542,190**	**40,744,863**	**39,289,296**	**39,243,869**	**39,398,169**	**39,871,569**

Table B.24– *continued*

Cost Component ($ 000)	Case 11	Case 14	Case 17	Case 18	Case 19	Case 20	Case 22
Variable Cost							
Total Fuel Cost	13,411,665	12,979,334	13,625,227	13,894,512	13,812,607	12,774,851	12,558,146
Variable O&M Cost	1,164,587	1,174,538	1,204,222	1,220,845	1,213,726	1,143,695	1,126,059
Total Emission Cost	14,159,325	13,634,228	13,469,668	13,714,767	13,595,382	12,647,703	12,781,992
Long Term Contracts and Front Office Transactions	5,631,083	6,175,357	8,669,522	7,235,524	7,133,223	5,769,274	6,241,471
DSM	3,254,961	3,365,567	3,186,054	3,023,493	3,133,315	3,287,687	3,483,403
Spot Market Balancing							
Sales	(12,613,055)	(13,377,546)	(13,388,006)	(12,487,968)	(12,604,973)	(12,725,027)	(13,660,143)
Purchases	4,057,005	3,475,485	3,546,102	4,357,831	4,236,310	3,868,019	3,281,495
Energy Not Served	136,344	118,697	168,279	173,946	173,290	136,891	113,066
Dump Power	(14,693)	(11,743)	(21,406)	(17,158)	(20,959)	(29,967)	(17,258)
Reserve Deficiency	60,344	38,241	63,344	68,008	72,674	54,843	31,939
Total Variable Net Power Costs	**29,247,566**	**27,572,157**	**30,523,005**	**31,183,800**	**30,744,594**	**26,927,968**	**25,940,171**
Real Levelized Fixed Costs	**11,787,530**	**14,908,880**	**9,610,984**	**9,000,946**	**9,768,684**	**15,198,946**	**17,635,612**
Total PVRR	**41,035,097**	**42,481,038**	**40,133,989**	**40,184,746**	**40,513,279**	**42,126,914**	**43,575,783**

Table B.24 – ***continued***

Cost Component ($ 000)	Case 24	Case 25	Case 26	Case 27	Case 29	Case 46	Case 47
Variable Cost							
Total Fuel Cost	12,231,023	13,129,485	12,576,599	12,220,360	12,238,723	15,333,331	15,396,709
Variable O&M Cost	1,099,133	1,168,243	1,121,716	1,098,935	1,132,357	1,298,792	1,301,473
Total Emission Cost	12,068,839	12,932,754	12,352,056	12,110,138	12,078,673	16,165,517	16,207,316
Long Term Contracts and Front Office Transactions	7,533,865	6,540,377	6,088,802	6,300,186	7,129,496	7,609,719	7,589,434
DSM	3,342,009	3,246,369	3,287,127	3,464,753	3,657,217	2,726,744	2,730,469
Spot Market Balancing							
Sales	(13,956,020)	(12,887,979)	(12,913,620)	(13,319,931)	(14,229,404)	(12,211,221)	(12,082,775)
Purchases	3,073,137	3,972,608	3,766,984	3,499,968	3,110,387	4,398,733	4,544,666
Energy Not Served	117,336	150,747	129,145	122,715	117,018	185,993	176,566
Dump Power	(27,096)	(28,268)	(25,987)	(29,421)	(24,641)	(10,206)	(10,145)
Reserve Deficiency	35,439	62,418	47,949	35,916	44,753	57,125	56,300
Total Variable Net Power Costs	**25,517,664**	**28,286,755**	**26,430,769**	**25,503,619**	**25,254,580**	**35,554,528**	**35,910,014**
Real Levelized Fixed Costs	**17,978,326**	**13,029,825**	**16,986,145**	**17,973,594**	**20,371,851**	**5,420,363**	**4,148,102**
Total PVRR	**43,495,990**	**41,316,580**	**43,416,914**	**43,477,213**	**45,626,430**	**40,974,891**	**40,058,117**

Table B.25 – Sensitivity Case: Portfolio PVRR Cost Components ($45 CO2 - Tax Strategy)

Cost Component ($ 000)	Case 04	Case 06	Case 07	Case 12	Case 13	Case 15	Case 16
Variable Cost							
Total Fuel Cost	15,884,444	15,730,813	14,991,433	14,562,408	13,537,752	11,929,242	14,206,320
Variable O&M Cost	1,338,612	1,351,623	1,271,070	1,237,469	1,170,671	1,100,516	1,236,954
Total Emission Cost	16,314,474	14,875,608	15,395,249	14,596,363	14,366,370	12,335,026	13,950,925
Long Term Contracts and Front Office Transactions	4,911,551	9,196,257	4,592,404	9,648,455	3,658,159	8,929,535	3,960,513
DSM	2,650,272	3,053,232	2,846,765	3,282,294	3,280,373	3,665,971	3,082,590
Spot Market Balancing							
Sales	(9,956,467)	(14,245,612)	(10,460,139)	(14,938,838)	(11,525,586)	(15,599,583)	(10,639,066)
Purchases	6,301,302	3,473,008	5,757,713	3,023,499	4,690,969	2,524,691	5,448,327
Energy Not Served	372,221	65,081	293,326	63,507	158,050	52,897	229,603
Dump Power	(11,262)	(10,881)	(11,158)	(12,168)	(11,069)	(15,063)	(18,523)
Reserve Deficiency	219,811	20,916	169,146	24,454	78,046	11,559	134,823
Total Variable Net Power Costs	**38,024,959**	**33,510,045**	**34,845,809**	**31,487,443**	**29,403,735**	**24,934,790**	**31,592,465**
Real Levelized Fixed Costs	**2,244,634**	**6,124,658**	**5,031,161**	**8,539,849**	**12,635,909**	**18,958,532**	**9,061,822**
Total PVRR	**40,269,592**	**39,634,703**	**39,876,970**	**40,027,293**	**42,039,643**	**43,893,322**	**40,654,287**

Table B.25 – *continued*

Cost Component ($ 000)	Case 21	Case 23	Case 28	Case 33	Case 41	Case 42	Case 43
Variable Cost							
Total Fuel Cost	13,007,111	12,578,685	12,742,452	12,501,704	14,418,506	13,740,869	12,159,435
Variable O&M Cost	1,160,870	1,120,171	1,138,737	1,114,443	1,241,622	1,215,560	1,094,393
Total Emission Cost	12,949,483	12,374,787	12,665,072	12,753,252	14,751,942	13,455,115	12,009,121
Long Term Contracts and Front Office Transactions	3,998,178	4,279,134	4,359,863	8,120,875	9,650,090	9,330,643	8,332,267
DSM	3,354,757	3,292,442	3,350,267	3,703,080	3,019,019	3,180,545	3,443,037
Spot Market Balancing							
Sales	(11,835,936)	(11,941,781)	(12,112,865)	(15,734,889)	(13,482,889)	(13,854,964)	(14,423,822)
Purchases	4,420,951	4,234,304	4,207,497	2,781,782	3,514,149	3,284,808	2,851,243
Energy Not Served	150,089	136,396	140,469	47,920	152,058	130,139	112,439
Dump Power	(16,975)	(23,563)	(21,984)	(24,885)	(10,982)	(19,997)	(27,081)
Reserve Deficiency	73,946	61,138	65,057	15,831	63,886	52,524	32,499
Total Variable Net Power Costs	**27,262,475**	**26,111,711**	**26,534,563**	**25,279,114**	**33,317,402**	**30,515,242**	**25,583,531**
Real Levelized Fixed Costs	**15,775,521**	**17,512,414**	**17,067,782**	**21,006,239**	**6,247,502**	**9,651,213**	**17,902,669**
Total PVRR	**43,037,996**	**43,624,125**	**43,602,345**	**46,285,353**	**39,564,904**	**40,166,454**	**43,486,200**

Table B.26 – B-Series Cases: Portfolio PVRR Cost Components ($45 CO2 - Tax Strategy)

Cost Component ($ 000)	Case 02b	Case 05b	Case 05b CCCT Dry	Case 05b CCCT Wet	Case 08b
Variable Cost					
Total Fuel Cost	14,981,715	14,323,649	15,157,854	15,208,477	13,688,145
Variable O&M Cost	1,287,418	1,253,185	1,312,868	1,310,220	1,204,987
Total Emission Cost	16,485,129	15,494,162	15,525,754	15,497,737	14,892,730
Long Term Contracts and Front Office Transactions	7,463,381	7,915,814	7,771,960	7,799,715	8,819,100
DSM	2,916,885	2,958,280	2,751,344	2,746,235	3,255,097
Spot Market Balancing					
Sales	(12,826,888)	(12,809,283)	(12,871,265)	(12,946,171)	(13,662,496)
Purchases	4,832,059	4,745,567	4,640,620	4,585,533	4,082,885
Energy Not Served	171,787	201,496	189,697	187,039	188,764
Dump Power	(10,619)	(10,784)	(9,671)	(9,597)	(11,626)
Reserve Deficiency	76,487	104,752	82,362	80,930	88,925
Total Variable Net Power Costs	**35,377,354**	**34,176,835**	**34,551,522**	**34,460,119**	**32,546,512**
Real Levelized Fixed Costs	**4,684,686**	**5,275,240**	**4,817,015**	**4,854,695**	**7,126,759**
Total PVRR	**40,062,040**	**39,452,075**	**39,368,538**	**39,314,814**	**39,673,271**

Table B.26– ***continued***

Cost Component ($ 000)	Case 09b	Case 10b	Case 17b	Case 18b	Case 47b
Variable Cost					
Total Fuel Cost	14,391,506	13,782,388	13,145,794	13,439,719	15,038,431
Variable O&M Cost	1,256,859	1,207,522	1,186,321	1,205,510	1,299,997
Total Emission Cost	15,555,068	14,920,273	13,645,023	13,938,418	16,354,069
Long Term Contracts and Front Office Transactions	7,300,096	8,078,996	8,712,260	7,478,893	7,581,800
DSM	2,948,350	3,230,797	3,390,861	3,259,964	2,863,945
Spot Market Balancing					
Sales	(12,421,787)	(13,137,936)	(14,185,362)	(13,217,280)	(12,797,023)
Purchases	5,035,985	4,610,885	3,790,156	4,544,153	4,773,896
Energy Not Served	217,010	191,297	166,406	180,757	177,657
Dump Power	(10,960)	(10,849)	(21,524)	(18,375)	(9,913)
Reserve Deficiency	114,217	89,352	72,750	79,612	54,371
Total Variable Net Power Costs	**34,386,343**	**32,962,725**	**29,902,685**	**30,891,372**	**35,337,229**
Real Levelized Fixed Costs	**5,338,215**	**7,298,315**	**10,636,072**	**9,461,888**	**5,169,437**
Total PVRR	**39,724,558**	**40,261,040**	**40,538,757**	**40,353,260**	**40,506,666**

APPENDIX C – IRP REGULATORY COMPLIANCE

BACKGROUND

Least-cost planning (i.e., Integrated Resource Planning) guidelines were first imposed on regulated utilities by state commissions in the 1980s. Their purpose was to require utilities to consider all resource alternatives—including demand-side measures—on an equal comparative footing, when making resource planning decisions. Integrated resource planning has expanded since then to incorporate the consideration of risk, uncertainty, and environmental externality costs into the resource evaluation framework. Planning rules were also intended to require utilities to involve regulators and the general public in the planning process prior to making resource decisions.

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

This appendix provides a discussion on how the 2008 IRP complies with the various state commission IRP Standards and Guidelines, 2007 IRP acknowledgement requirements, and other commission decisions. Included at the end of this appendix are the following tables:

- Table C.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.[1]
- Table C.2 – Provides a description of how the 2007 IRP acknowledgement requirements and other commission requests were addressed.
- Table C.3 – Provides an explanation of how this plan addresses each of the items contained in the new Oregon IRP guidelines issued in January 2007.
- Table C.4 – Provides an explanation of how this plan addresses each of the items contained in the Utah Public Service Commission IRP Standard and Guidelines issued in June 1992.
- Table C.5 – Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Trade Commission IRP guidelines issued in January 2006.

GENERAL COMPLIANCE

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the state commissions. The preparation of the IRP is done in an open public process with consultation between all interested parties, including commissioners and commission staff, customers, and other

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[1] California and Wyoming requirements are not summarized in Table C.1. The Wyoming requirements are discussed in the chapter text. California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP.

stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, described in Volume 1, Chapter 2, as well as in Appendix E, fully complies with the IRP Standards and Guidelines.

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

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 7 and 8, meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of numerous risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western Interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described at a high level in Chapter 2 and in greater detail in Chapter 7.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 8.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 9). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. Appendix D provides a progress report that relates the 2007 IRP Action Plan with those provided in the 2007 IRP and 2007 IRP Update.

The 2008 IRP and the related Action Plan are filed with each commission with a request for prompt acknowledgement. Acknowledgement means that a commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgement is made. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets acknowledgement standards.

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

California

Subsection (i) of California Public Utilities Code, Section 454.5, states that utilities serving less than 500,000 customers in the state are exempt from filing an Integrated Resource Plan for California. PacifiCorp serves only 45,072 average customers in the most northern parts of the state. PacifiCorp filed for and received an exemption on July 10, 2003.

Idaho

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

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

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2007, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 6 and 7. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in IPUC Order No. 21249.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its new planning guidelines issued in January 2007 (Order No. 07-002). These guidelines supersede previous ones, and many codify analysis requirements outlined in the Commission's acknowledgement order for PacifiCorp's 2004 IRP.

The Commission's new IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), and resource acquisition (Guideline 13). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgement does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table C.3 provides considerable detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Utah Public Service Commission in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table C.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238), and the rule amendment issued on January 9, 2006 (WAC 480-100-238, Docket No. UE-030311). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan."

The rule amendment also now requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on February 21, 2006, and had a follow-up conference call with WUTC staff to make sure the work plan met staff expectations.

Finally, the rule amendment now requires PacifiCorp to provide an assessment of transmission system capability and reliability. This requirement was met in this IRP by modeling the company's current transmission system along with both generation and transmission resource options as part of its resource portfolio analyses. These analyses used such reliability metrics as Loss of Load Probability and Energy Not Served to assess the impacts of different resource combinations on system reliability. The stochastic simulation and risk analysis section of Chapter 7 reports the reliability analysis results.

Wyoming

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

In 2009, Wyoming proposed a draft rule 253 for any utility serving Wyoming to file their Integrated Resource Plan with the commission. This rule is still under review and is open for public comment until April 27, 2009 and with a schedule public hearing on May 12, 2009.

> *Rule 253: Integrated Resource Planning.*
> *Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.*

Table C.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho
Source	Order 89-507 *Least-cost Planning for Resource Acquisitions,* April 20, 1989. Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking,* January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation and low-income programs.
Frequency	Plans filed biennially. Interim reports on plan progress also required (informational filing only). Order 07-002 requires IRP filing within two years of its previous IRP acknowledgement order.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.
Commission response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgement order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP *acknowledged* if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.

Topic	Oregon	Utah	Washington	Idaho
Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. For the amended rules issued in January 2006, PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.
Elements	Basic elements include: ● All resources evaluated on a consistent and comparable basis. ● Risk and uncertainty must be considered. ● The primary goal must be least cost, consistent with the	IRP will include: ● Range of forecasts of future load growth ● Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis.	The plan shall include: ● A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	Discuss analyses considered including: ● Load forecast uncertainties; ● Known or potential changes to existing resources; ● Equal consideration of demand and supply side resource options;

Topic	Oregon	Utah	Washington	Idaho
	long-run public interest. ● The plan must be consistent with Oregon and federal energy policy. ● External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). ● Identify acquisition strategies for action plan resources, assess advantages/disadvantages of resource ownership versus purchases, and identify benchmark resources considered for competitive bidding. ● Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. ● Avoided cost filing required within 30 days of acknowledgement.	● Analysis of the role of competitive bidding ● A plan for adapting to different paths as the future unfolds. ● A cost effectiveness methodology. ● An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. ● Definition of how risks are allocated between ratepayers and shareholders ● DSM and supply side resources evaluated at “Total Resource Cost” rather than utility cost.	● An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. ● Assessment of a wide range of conventional and commercially available nonconventional generating technologies ● An assessment of transmission system capability and reliability (Added per amended rules issued in January 2006). ● A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using “lowest reasonable cost” criteria. ● Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. ● All plans shall also include a progress report that relates the new plan to the previously filed plan.	● Contingencies for upgrading, optioning and acquiring resources at optimum times; ● Report on existing resource stack, load forecast and additional resource menu.

Table C.2 – Handling of 2007 IRP Acknowledgement and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
Idaho		
Acceptance of Filing, Case No. PAC-E-07-11, p. 9	Staff further recommends that the Company address modifications to its 2007 resource acquisition strategies on a state-by-state basis in the form of periodic updates to its 2007 IRP.	Stakeholder and Bidder meetings are held throughout the RFP process on a periodic basis.
Acceptance of Filing, Case No. PAC-E-07-11, p. 9	Staff also recommends that the Company investigate critical peak pricing programs to augment its existing time-of-use schedule. Staff considers the deployment of advanced metering to be an indispensable part of that investigation.	Critical Peak Pricing (CPP) programs (Class 3 DSM) are included as resource options for portfolio modeling. PacifiCorp developed a sensitivity portfolio with these resources and other price-response programs, and simulated it using its stochastic production cost model (Chapter 8). Class 3 DSM programs are addressed in Item 7 of the IRP action plan (Chapter 9).
Acceptance of Filing, Case No. PAC-E-07-11, p. 10	Given the increasing role of jurisdictional resource mandates in the planning process, Staff further recommends that future IRPs incorporate a section devoted to the impacts, if any, of state policies on the selection of preferred portfolios.	State RPS requirements are explicitly accounted for in resource portfolio modeling, and the company is in the process of implementing capacity expansion modeling enhancements to improve representative of jurisdiction-specific CO_2 and RPS rules. Please refer to Chapter 3 RPS discussion and Chapter 7 discussing the Alternative Scenarios. State environmental/energy policies are discussed in Chapters 3, and are addressed in the IRP action plan (Chapter 9)
PURPA QF Wind, ID PAC-E-07-07, p. 6	(PacifiCorp) shall hereafter file notice with the Commission of any changes to its wind integration charge as reflected in subsequent changes to its IRP.	PacifiCorp is preparing an update to its wind integration cost estimates. This updated information will be provided in the final IRP document to be filed with state commissions by May 29, 2009
PURPA QF Wind, ID PAC-E-07-07, p. 6	Expected wind integration cost information will be included in the Company s integrated resource planning (IRP) process in the same way that costs for other generating resources are included in the IRP.	See slide 2 from the December 2, 2008 Conference, showing the adoption of PGE's integration cost of $11.75/MWh in 2008 dollars. This value was treated as a placeholder until the company completes its wind integration study
PURPA QF Wind, ID PAC-E-07-07, p. 7	Idaho wind developers will be notified as part of the public meeting process and can contribute their input at those meetings to discuss PacifiCorp s wind integration study and new data related to wind integration costs prior to the publishing of the Company s next (2009) IRP.	PacifiCorp has added several contacts for Idaho wind developers to the participant list. PacifiCorp held a wind integration cost technical conference on December 2, 2008.
Oregon		

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
Order No. 08-232, LC-42, p. 13	Staff also recommends further consideration of nuclear passive safety and pumped storage technologies in the next planning cycle.	PacifiCorp included advanced nuclear and pumped storage technologies as resource options in portfolio modeling. See Chapters 6 and 7.
Order No. 08-232, LC-42, p. 14	Addressing a requirement from the last planning cycle, the IRP includes a discussion of how various thermal resources affect wind integration costs. Staff recommends a more thorough discussion in the next resource plan.	See Appendix H for additional information on wind integration costs, to be provided when the IRP is filed May 29, 2009.
Order No. 08-232, LC-42, p. 15	Staff recommends the Company take a hard look at low market price scenarios in analyzing its resource choices. Such possible futures point out the risks of capital-intensive, base load resources.	PacifiCorp developed seven portfolios using low market price assumptions. See Chapter 7 for portfolio input assumptions.
Order No. 08-232, LC-42, p. 17	The IRP includes a cursory discussion of hedging. Staff recommends a more robust discussion of hedging in future resource plans. Commission agrees with staff…"[the] plan should include a more substantive discussion of hedging as specified by Guideline 1c.	See Chapter 9 for a discussion on Use of Physical and Financial Hedging for Electricity Price Risk.
Order No. 08-232, LC-42, p. 21	Staff recommends the Company model market purchases for the later years of the plan in order to consistently compare portfolios, and not inappropriately weight resource decisions in the distant future.	The 2008 IRP extends front office purchases to end of the simulation period (2028), and also specifies Growth Resources, available to the model after 2020, using forward market prices. See the section in Chapter 7, "Modeling Front Office Transactions and Growth Resources".
Order No. 08-232, LC-42, p. 26	We therefore support the agreed-upon modifications to Action Items 3 and 4 related to demand response resources. [Staff's concerns that the IRP may have underestimated the level of risk-adjusted, cost-effective demand response.]	See Chapter 6 on Resource Options and the results in Chapter 8.
Order No. 08-232, LC-42, p. 29	Pacific Power's next plan should further evaluate solar direct use and generating resources.	PacifiCorp complied with this recommendation. See Chapter 6 on the additional solar options included for portfolio development.
Order No. 08-232, LC-42, p. 36	4. In the next planning cycle, include IGCC plants with carbon capture and sequestration as a resource option for selection.	PacifiCorp included IGCC plants with CCS as resource options in all the portfolios modeled. See Chapter 6 for resource specifications and background information.
Order No. 08-232, LC-42, p. 36	5. In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.	In formulating market purchase options for the IRP models, the company lacked information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the company anticipated using bid information from the 2008 All-Source RFP to inform the development of

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
		intermediate-term market purchase resources for modeling purposes. The company received no intermediate-term market purchase bids; therefore, such resources could not be reasonably modeled for this IRP. (See Chapter 6, "Resource Options)
Order No. 08-232, LC-42, p. 36	6. For the 2007 IRP update and next planning cycle, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.	PacifiCorp designed a portfolio analysis to address this requirement, estimating a system-wide hard cap based on Oregon's HB 3543 emission reduction goals. The company corrected a deficiency with the analysis pointed out by OPUC staff (assigning an emission rate to market purchases). A description of this portfolio scenario ("case 40") is provided in Chapter 7; modeling results are provided in Chapter 8.
Order No. 08-232, LC-42, p. 36	7. For the next planning cycle, further develop with stakeholders use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.	See the sections in Chapter 8 discussing the LOLP and ENS modeling results. PacifiCorp will investigate functionality in the company's capacity expansion optimization model (System Optimizer) to apply an LOLP constraint. This activity is identified in Action Plan item no. 9, Planning Process Improvements.
Order No. 08-232, LC-42, p. 36	8. For the next planning cycle, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.	Forced early retirement is discussed in Chapter 9 under Managing Carbon Risk for Existing Plants. The option of retrofits is a resource option in the portfolio development process.
Order No. 08-232, LC-42, p. 36	9. Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emissions rates to short-term market transactions.	PacifiCorp is implementing System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. This activity is identified in Action Plan item no. 9, Planning Process Improvements. Development of this functionality was complicated and could not be completed in time for this IRP.
Order No. 08-232, LC-42, p. 37	1. For the 2007 IRP Update and next IRP, Pacific Power should model other renewable resources in addition to wind.	PacifiCorp included geothermal, biomass, solar, and hydrokinetic technologies as resource options in portfolio modeling. See Chapter 6 "Resource Options" and Chapter 7 "Modeling and Portfolio Evaluation Approach".
Order No. 08-232, LC-42, p. 37	2. For the next IRP, Pacific Power should rank portfolios based on the 95th Percentile and Upper-Tail PVRR risk metrics, and explain any inconsistencies between portfolios that rank highest	PacifiCorp reports the 95th Percentile and Upper-Tail PVRR metrics, along with a new measure called risk-adjusted PVRR, which was used for "2012 Base-load RFP" bid evaluation. The risk exposure measure was

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
	according to these measures and the Company's preferred portfolio.	dropped from the IRP. See Chapters 7 and 8 for descriptions of the risk measures and the portfolio ranking process, respectively. For portfolio ranking purposes, incorporation of the risk-adjusted PVRR in the preference scoring process addresses the requirement to reflect an upper-tail risk measure in portfolio ranking. However, Table B.23 in the Appendix volume shows an alternate ranking scheme where the upper-tail mean PVRR is included as a separate performance measure and given an importance weight nearly as large as the mean PVRR. This alternate ranking scheme is applied to the final 10 portfolios considered for preferred portfolio selection.
Order No. 08-232, LC-42, p. 37	3. For the next IRP, in response to concerns noted in this order, Pacific Power should further analyze and discuss the use of hedging, the level of short-term market purchases, projected load growth, modeling of resources to meet loads in the later years of the planning horizon, capital cost risks and assumed economic lives of coal plants, and the appropriate level of distributed generation.	• Hedging is addressed in Chapter 9. • PacifiCorp modeled market purchases based on several forward price futures (low, medium, high), and applying forward price curves developed at two points in time (See Chapter 7) • PacifiCorp modeled alternative load growth scenarios, and conducted portfolio analysis with two load forecasts developed in November 2008 and February 2009 • Resources, other than "growth resources", were allowed as model options for capacity expansion modeling (See Chapter 7) • PacifiCorp included 10-year capital costs as a portfolio performance evaluation measure, and developed a portfolio assuming a 20% increase in capital costs • Distributed generation resources (CHP and customer standby generation) were included as resource options in all portfolios modeled; the appropriate level of distributed generation is addressed in item no. 9 of the IRP action plan (Chapter 9)
Utah		
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company, in its next IRP process, to convene a public input meeting or technical workgroup session to review its approach to load forecast variation and to address the issue of load forecast error risk. This discussion must include the Committee's concerns	PacifiCorp held a load forecasting technical workshop on June 26, 2008. PacifiCorp attended two meetings with Utah parties to discuss various IRP and load forecasting issues (April 9 and May 14, 2008).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
	regarding use of 30-year normal temperatures for estimating peak demand, the number of years relied upon for developing stochastic parameters, and the role of planning reserve in managing the risks of forecast error.	
UT-07-2035-01, Report & Order, 2-6-08, p. 16	We direct the Company to continue to study the tradeoffs in planning to different planning reserve targets in future IRPs.	PacifiCorp's planning reserve margin analysis is summarized in Chapter 8.
UT-07-2035-01, Report & Order, 2-6-08, p. 17	We direct the Company to address [the issue of hydro capacity accounting] in its next IRP. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of [using the sustainable one-hour peak capacity method applied for the 2007 IRP]	This requirement is addressed in Chapter 5, Resource Needs Assessment, in the discussion on hydro resources.
UT-07-2035-01, Report & Order, 2-6-08, p. 23	We direct the Company to evaluate a full spectrum of supply-side and demand-side options which have different characteristics regarding size, dispatchability, expected cost, expected risks and lead time for construction. Modeling limitations will need to be addressed.	See Chapter 5 "Resource Options" for a description of the expanded number of resources included in portfolio modeling.
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company to host a public input meeting or technical workgroup to examine the reasonableness of the range of CO_2 adders for evaluating carbon regulation risk and risk mitigating resource strategies.	PacifiCorp held a public input meeting on modeling CO2 regulations (including specification of CO_2 adders) on June 26, 2008.
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company to consider the following three-step approach for developing its optimal portfolio: 1) Identify optimal portfolios for a relatively broad, and consistently applied, set of input assumptions; 2) subject all of these optimal portfolios to stochastic risk analysis and identify superior optimal portfolios with respect to the tradeoff between expected cost and risk exposure; 3) examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions.	See Chapter 7 "Modeling and Portfolio Evaluation Approach". This three-step approach was implemented for this IRP. The assessment of the value of step 3 is provided in Chapter 8.
UT-07-2035-01, Report & Order, 2-6-08, p. 13	We direct the Company, with public input, to develop a manageable set of potential future conditions, defined by a consistently applied set of input assumptions, and to develop a set of optimal portfolios	PacifiCorp has complied with this directive, and sought public input on the specification of input assumption scenarios at several public meeting during2008. The company initially developed 47 input assumption

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
	consistent with these sets of conditions.	scenarios ("cases"), developed resource portfolios optimized according to these scenarios, and subjected these portfolios to stochastic (Monte Carlo) production cost simulation. The company subsequently developed another 10 portfolios accounting for the removal of the Lake Side 2 combined-cycle plant as a planned resource in 2012, and using a consistent set of input cases to do so (the cases that yielded the original top-performing portfolios).
Washington		
Letter Order, UE-071062, p. 1	PacifiCorp does need to identify and better support significant changes it makes to base demand projections relative to previous IRPs. For example, no explanation is given as to why this IRP cut the expected demand growth in Washington by 50 percent.	See Chapter 5 "Resource Needs Assessment" and Chapter 8 for details on the load forecasts used. The company held several conference calls with public stakeholders describing the reason for load forecast adjustments having to do with recessionary impacts.
Letter Order, UE-071062, p. 1	The company should also improve the presentation of its two-year action plan.	The company has provided more detail in the IRP action plan, included an acquisition path analysis, and addressed several resource risk management topics not addressed in previous IRPs. See chapter 9.
Letter Order, UE-071062, p. 2	The Commission expects the company to use the Quantec estimates as the basis for its conservation program achievement objective rather than the one included in the IRP.	PacifiCorp developed energy efficiency supply curves based on the Cadmus Group (previously Quantec LLP) potentials information. See the discussion on supply curve development in Chapter 6. These supply curves served as resource options in the capacity expansion model.
Letter Order, UE-071062, p. 2	In its next plan, the company needs to better explain how it chose the transmission options to study, the process used to integrate the selection of both new generating resources and transmission expansions/enhancements, and how the transmission expansion will affect system operation, dispatch of resources and the flow of electricity throughout PacifiCorp's service territory.	PacifiCorp included a new "Transmission planning" chapter (Chapter 4), and included a separate transmission expansion action plan in Chapter 9.
Letter Order, UE-071062, p. 3	Therefore, we remind the company that any baseload resources put in service after June 30, 2008 to serve Washington customers, or any transmission that allows the output of such resources to reach Washington must comply with this state's statutory requirements.	PacifiCorp will follow state statutory requirements for delivery of energy to Washington.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2008 IRP
Letter Order, UE-071062, p. 3	What is unclear from this discussion is how PacifiCorp will determine when a revision in the planning margin is warranted. PacifiCorp needs to identify the metrics it will use or the processes it will monitor that could lead the company to alter its new planning margin.	PacifiCorp will investigate the use of a LOLP capacity constraint in its capacity expansion model to supplement the current planning reserve margin approach (See Chapter 9, action item no. 9). Development of a process to modify planning reserve margins has thus been put on hold. PacifiCorp is also monitoring WECC resource supply adequacy criteria for possible implications to the IRP.
Letter Order, UE-071062, p. 4	As part of its next plan, PacifiCorp should more thoroughly explain why its preferred portfolio provides greater benefits and/or is lower risk than the alternative portfolios.	See chapter 8 for an in-depth discussion on the merits and disadvantages of the preferred portfolio relative to other top-performing portfolios.
Letter Order, UE-071062, p. 4	PacifiCorp should derive avoided cost for transmission and distribution resources. These avoided costs will guide generators or suppliers as they determine if they can supply electricity below the company's avoided cost.	PacifiCorp incorporated a T&D investment deferral cost credit to demand-side management program costs.
Letter Order, UE-071062, p. 1	The action plan needs to provide much more specific information regarding the actual steps the company will take to complete the identified action items.	The IRP action plan provides more detail on procurement approaches for resources identified in the IRP preferred portfolio (See Table 9.2 in Chapter 9).
Wyoming		
The Wyoming Commission provided the following comment: *Pursuant to open meeting action taken on January 11, 2008, PacifiCorp d/b/a Rocky Mountain Power's 2007 Integrated Resource Plan (IRP) is hereby placed in the Commission's files. No further action will be taken and this docketed matter is closed.*		

Table C.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, distributed generation, energy storage, power purchases, thermal resources, and transmission. Chapters 6 and 7 document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, and selected by the model based on relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with the capacity expansion optimization model were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, life-times, and locations.
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Cadmus Group's supply curve data for representation of DSM and distributed generation resources, which was also based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Chapters 6 and 7.
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its after-tax WACC of 7.4 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	PacifiCorp fully complies with this requirement. Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation. See the stochastic modeling methodology section in Chapter 7.
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	PacifiCorp complied with this guideline by discussing resource risk mitigation in Chapter 9. Topics covered include: (1) managing carbon risk for existing plants, (2) the use of physical and financial hedging for

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
		electricity price risk, and (3) managing gas supply risk. Regulatory and financial management risks associated with a large capital expenditure program were highlighted in several areas throughout the IRP document.
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered, significantly expanding its representation of CO_2 cost risk and implementing a multi-measure portfolio preference ranking scheme. See Chapter 8 for the company's portfolio risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects consistent with past IRP practice.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PacifiCorp fully complies. Chapter 7 provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail PVRR (mean of highest five Monte Carlo iterations) and the 95th percentile stochastic PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on costs and risks of physical and financial hedging is provided in Chapter 9.
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 8 summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and expected state and federal energy policies in portfolio modeling. Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state resource policies. The IRP action plan chapter also presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes	PacifiCorp fully complies with this requirement. Chapter 2 provides an overview of the public process, while Appendix D documents the details on public

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	meetings held for the 2008 IRP.
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	Both IRP volumes provide non-confidential information the company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed a draft IRP document for external review on April 8, 2009.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	This Plan complies with this requirement.
3.b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PacifiCorp will adhere to this guideline.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	Not applicable
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	Not applicable
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable
3.f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may	Not applicable

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	request acknowledgment of changes in proposed actions identified in an update.	
3.g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1. Describes what actions the utility has taken to implement the plan; 2. Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3. Justifies any deviations from the acknowledged action plan.	Not applicable
Guideline 4. Plan Components (at a minimum, must include…)		
4.a	An explanation of how the utility met each of the substantive and procedural requirements	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	PacifiCorp developed low, medium, and high load growth forecasts for scenario analysis using the System Optimizer model for portfolio development. Stochastic variability of loads was also captured in the risk analysis. See Chapters 5 and 8, and Appendix E, for load forecast information. Chapter 8 also describes how loads are handled in the stochastic modeling.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested	This Plan complies with the requirement. See Chapter 5 for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies, as mentioned in Chapter 7.
4.d	For gas utilities only	Not applicable
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology	Chapter 6 identifies the resources included in this IRP, and provides their detailed cost and performance attributes. See Tables 6.2 through 6.10 for supply-side resources, and Tables 6.15 through 6.20 for demand-side resources.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs	In addition to incorporating a planning reserve margin for all portfolios evaluated, the company used several measures to evaluate relative portfolio supply reliability. These are described in Chapter 7 (Energy Not Served and Loss of Load Probability). PacifiCorp conducted a sensitivity study to determine the cost/risk tradeoff of different planning reserve margin levels. This study is documented in Chapter 8.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance	Chapter 7 describes the key assumptions and alternative scenarios used in this IRP.

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	costs) and alternative scenarios considered	
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system	This Plan documents the development and results of 57 portfolios designed to determine resource selection under a variety of input assumptions (Chapter 8).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 8 presents the stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 8 provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	PacifiCorp fully complies with this guideline. See the responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is presumed to have no inconsistencies.
	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapters 9 and 10 presents the 2008 IRP and transmission expansion action plans, respectively.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated proxy transmission resources on a comparable basis with respect to other proxy resources in this IRP. Fuel transportation costs were factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potentials study was completed in June 2007, and those results were incorporated into this plan.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See Chapter 6, "Class 2 DSM, Capacity Supply Curves"
6.c	To the extent that an outside party administers	See the response for 6.b above.

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 3 DSM) on a consistent basis with other resources in a portfolio study, and simulated the portfolio containing class 3 DSM resources using its stochastic production cost model (Chapter 8). Class 3 DSM programs are addressed in Item 7 of the IRP action plan in Chapter 9.
Guideline 8: Environmental Costs		
8	a. Base Case and Other Compliance Scenarios b. Testing Alternative Portfolios Against the Compliance Scenarios c. Trigger Point Analysis d. Oregon Compliance Portfolio	This IRP fully complies with the CO_2 compliance cost analysis requirements in Order No. 08-339. Performance results for CO_2 compliance scenario portfolios are reported in Chapter 8, as well as an Oregon compliance scenario (See Table C.2). Chapter 9 presents a discussion on "whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated" as required in Guideline 8c.
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	PacifiCorp continues to plan for load for direct access customers.
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2008 IRP conforms to the multi-state planning approach as stated in Chapter 2.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural	PacifiCorp fully complies with this guideline. See the response to 1.c.3.1 above. Chapter 8 describes the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost adder levels were used to inform the cost/risk tradeoff analysis. (Chapter 8).

No.	Requirement	How the Guideline is Addressed in the 2008 IRP
	gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp evaluated several types of distribution generation, including combined heat and power and customer-owned standby generation. The results of these evaluations are documented in Chapter 8.
Guideline 13: Resource Acquisition		
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party 3. Identify any Benchmark Resources it plans to consider in competitive bidding	Chapter 9 outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 9. Company resources included in RFPs is addressed in the action plan (Table 9.2 and accompanying narrative).
13.b	For gas utilities only	Not applicable

Table C.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Utah Public Service Commission responsibility
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.	Not addressed; ratemaking occurs outside of the IRP process
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix D.
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Chapter 7 for a description of

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		the methodology employed, including how CO2 cost uncertainty is factored into the determination of relative portfolio performance.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp's capacity expansion optimization model. Also see the response to number 4.b.ii below.
7	Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	Consistent with the Utah rules, PacifiCorp determination of avoided costs will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Chapter 2 outlines the IRP/business plan alignment effort that was initiated in 2008 and will continue through 2009. Chapter 9 also describes recent IRP/business planning alignment activities associated with selection of a preferred portfolio.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	PacifiCorp implemented a highly transparent portfolio preference scoring methodology that incorporates numerous portfolio performance measures and considers CO_2 cost uncertainty in the portfolio ranking process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The Company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on May 30, 2007, and filed this IRP on May 29, 2009. PacifiCorp planned to file the IRP with all commissions on March 31 in each odd-numbered year. However, the Lake Side 2 decision prompted the company to revise the IRP accordingly, including conducting additional portfolio analysis.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix D.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
	parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2008 IRP are provided in Chapters 5 and 8, and Appendix E. Figures 7.3 and 7.4 in Chapter 7 show the range of forecasts used for capacity expansion modeling. Figures 7.22 through 7.26 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	Price risk associated with market sales is captured in the company's stochastic simulation results. Current off-system sales agreements are included in the IRP models.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Chapter 5 documents how demographic and price factors are used in PacifiCorp's new load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model.
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Chapter 6.
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Chapters 6 and 7 document how PacifiCorp developed and assessed these technologies.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves and distributed generation resources used for portfolio modeling explicitly incorporate estimated

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
	opportunities for customer participation.	rates of program and event participation. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Chapter 9.
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2009-2028)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Chapter 9. As mentioned in the chapter, the major preferred portfolio resources were evaluated for financial and rate impacts by the PacifiCorp Energy Finance Department in alignment with business planning protocols. A status report of the actions outlined in the previous action plan (2007 IRP update) is provided in Chapter 9 as well. The action plan (Table 9.2) also identifies actions anticipated to extend beyond the next two years, or occur after the next two years
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Chapter 9 includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, combinations of load growth and gas price futures, and procurement delays. The decision mechanism for pursuing the resource strategies is the outcome of the annual business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Chapter 7. The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Portfolios were evaluated using a range of CO_2 cost futures ● A discussion of environmental policy status and impacts on utility resource planning is provided in Chapter 3.
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Chapter 9, and covers the following topics: (1) managing carbon risk for existing plants, (2) the use of physical and financial hedging for electricity price risk, and (3) managing gas supply risk. Regulatory and financial management risks associated with a large capital expenditure program were highlighted in several areas throughout the IRP, and in relation to IRP and

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		business plan alignment. Resource capital cost uncertainty and technological risk is addressed in Chapter 6 (“Handling of Technology Improvement Trends and Cost Uncertainty”). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Chapter 9.
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Chapter 9 and the action plan (Table 9.2). In Chapter 8, PacifiCorp discusses how planning flexibility came into play for the timing of preferred portfolio resources such as wind.
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk. This trade-off analysis is documented in Chapter 8, and highlighted through the use of scatter plot graphs showing the relationship between expected and upper-tail stochastic PVRR.
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp estimated environmental externality costs for CO_2, NO_X, SO_2, and mercury with use of cost adders and assumptions regarding the form of compliance strategy (for example, cap-and-trade versus a per-ton tax for CO_2). For CO_2 externality costs, the company used scenarios with various cost adder levels to capture a reasonable range of cost impacts. These adders are described in Chapter 7.
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Chapter 6.
5	PacifiCorp will submit its IRP for public comment, review and acknowledgement.	PacifiCorp distributed the draft IRP document for public review and comment on April 8, 2009.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with	Not addressed; this is a post-filing activity.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
	comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.	
7	Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table C.5 – Washington Utilities and Trade Commission IRP Standard and Guidelines (WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the IRP work plan on January 18, 2008; at that time, the anticipated IRP filing date was January 20, 2009.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 2-3 of the Work Plan document for a summarization of resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See Figure 2, page 6 of the Work Plan document for the IRP schedule.
(4)	Integrated resource plan submitted within two years of previous plan.	The Commission issued an Order on December 11, 2008, under Docket no. UE-070117, granting the Company permission to file its IRP on March 31 of each odd numbered year. On March 26, 2009, the Commission granted PacifiCorp a temporary exemption from the March 31st deadline allowing the Company to file its 2008 integrated resource plan on May 29, 2009 (Docket No. UE-081475).
(5)	Commission issues notice of public hearing after company files plan for review.	Not applicable
(5)	Commission holds public hearing.	Not applicable
(2)(a)	Plan describes the mix of energy supply resources.	Chapter 8 describes the 2008 IRP preferred portfolio. For example, see Tables 8.44 and 8.45, as well as Figures 8.29 and 8.30.
(2)(a)	Plan describes conservation supply.	See Chapter 8, Tables 8.44 and 8.45, as well as Figures 8.29 and 8.30.
(2)(a)	Plan addresses supply in terms of current and future needs.	The 2008 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the Company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Chapter 5. For example, see Table 5.20 for PacifiCorp's capacity load and resource balance.
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Chapter 7.
(2)(b)	LRC analysis considers resource costs.	Chapter 6, Resource Options, provides detailed information on costs and other attributes for all resources analyzed for the IRP. For example, see Tables 6.2 through 6.10, 6.15 through 6.18, and 6.20.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. See the section entitled, "Monte Carlo Production Cost Simulation" in Chapter 7 for a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints,
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory costs, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Chapter 9 covers the following topics: (1) managing carbon risk for existing plants, (2) the use of physical and financial hedging for electricity price risk, and (3) managing gas supply risk. Regulatory and financial management risks associated with a large capital expenditure program were

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
		highlighted in several areas throughout the IRP, and in relation to IRP and business plan alignment.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	The IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington, Oregon, California, and Utah. (See Chapter 7, "Representation and Modeling of Renewable Portfolio Standards", as well as Appendix A for RPS compliance reports developed for each resource portfolio assessed for the IRP). PacifiCorp also evaluated various CO_2 regulatory schemes, including a CO_2 tax, hard cap, and cap-and-trade. Future modeling enhancements are planned for improved representation of state-level resource regulations.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	A description of PacifiCorp's modeling of CO_2 cost risk is provided in Chapter 7, "Carbon Dioxide Compliance Strategy and Costs". Chapter 9 also discusses the implications of CO_2 cost uncertainty on resource acquisition plans. See Table 9.3.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Chapter 6, "Demand-side Resources".
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2008 IRP are provided in Chapters 5 and 8, and Appendix E. Figures 7.3 and 7.4 in Chapter 7 show the range of forecasts used for capacity expansion modeling. Figures 7.22 through 7.26 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Chapter 5, "Load Forecast", for a description of the load forecasting methodology.
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Chapter 5, "Load Forecast", for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp conducted a comprehensive system-wide demand-side management potential study in 2007, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. The DSM potential study is posted on PacifiCorp's Web page: http://www.pacificorp.com/Article/Article75535.html, and has been provided to the WUTC on a CD.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2008 IRP
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Chapter 5, Resource Needs Assessment ("Existing Resources").
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Chapters 6 and 7 document how PacifiCorp developed and assessed these technologies.
(3)(d)	Plan includes an assessment of transmission system capability and reliability (as allowed by current law).	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans (See the "Transmission System Representation" section in Chapter 7). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. The DSM potentials study considered improvements in conservation Distribution considered alternative transmission expansion options.
(3)(f)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Chapter 7. Portfolio evaluation covers a 20-year period (2009-2028). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.2, Chapter 9, for PacifiCorp's 2008 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	A status report on action plan implementation is provided in the "Progress on Previous Action Plan Items" section of Chapter 9.
(5)	Plan includes description of consultation with commission staff. (Description not required)	Chapter 2 includes a summary of the 2008 IRP public process, while Appendix D provides deals on specific meetings held with Commission staff and the general public.
(5)	Plan includes description of completion of work plan. (Description not required)	Not applicable; the IRP schedule was modified to accommodate significant planning events. See the response to WAC 480-100-238(4).

APPENDIX D – PUBLIC INPUT PROCESS

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

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

The cornerstone of the public input process has been full-day public input meetings held approximately throughout the year-long plan development period. These meetings have been held jointly in two locations—Salt Lake City, Utah and Portland Oregon—using telephone and video conferencing technology.

A key change to the IRP public process occurring during the analysis preparation phase was the state stakeholder dialogue sessions from mid-March through April 2008. (For prior IRPs, the Company relied solely on general public meetings open to all participants.) These goal of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state, and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. This change in public process enhance interaction with stakeholders early on in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during general public meetings.

As far as agenda setting is concerned, PacifiCorp solicited recommendations from the state stakeholders in advance of the session, as well as allowing open time to ensure that participants had adequate time for dialogue. Some follow-up activities arising from the sessions were addressed in subsequent public meetings or another state meeting.

The 2008 public input meetings were augmented by a series of focused technical workshops to provide an opportunity to discuss complex topics for a multi-state utility in more detail.

PARTICIPANT LIST

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

Commissions

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

Intervenors

- Brigham Young University
- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- ECOS Consulting
- Energy Trust of Oregon
- Energy Strategies, LLC
- Health Environment Alliance of Utah (HEAL)
- Horizon Wind Energy
- Industrial Customers of Northwest Utilities
- Kennecott
- Mountain West Consulting, LLC
- Northwest Power and Conservation Council
- NW Energy Coalition
- Oregon Department of Energy
- Renewables Northwest Project
- Salt Lake City
- Salt Lake Community Action Program
- Southwest Energy Efficiency Project
- Sierra Club , Utah Chapter
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Air Quality
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Geological Survey
- Wasatch Clean Air Coalition
- Western Resource Advocates
- West Wind Wires
- Wyoming Industrial Energy Consumers
- Wyoming Office Of Consumer Advocacy

Others

- Portland General Electric (PGE)
- Avista Utilities
- Cadmus Group Inc. – Stuart McMenamin

- John Klingele (Washington Customer)

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

PUBLIC INPUT MEETINGS

PacifiCorp hosted five full-day public input meetings, two half day meetings, one conference call and six state meetings during the 2008. During the 2008 IRP process presentations and discussions covered various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings and the technical workshops.

General Meetings

February 29, 2008

- IRP Regulatory Compliance
- IRP Process Improvements
    - IRP/Business Plan Alignment Strategy
    - Public Process Changes
    - IRP Report Changes
- 2008 IRP Modeling Plan
- 2008 IRP Activity Timeline
- 10-Year Business Planning Process
- Resource Portfolio Development for the IRP Update/2008-2017 Business Plan
    - Load Forecast
- Demand-side Management Resources
- Capacity Load and Resource Balance
- Resource and Other Input Assumptions
- Resource Additions

May 22, 2008

- Update to the 2008 IRP Modeling Plan
- Case Definitions for Portfolio Development
- Natural Gas and Electricity Forecasts
- Resource Characterization
    - Supply side resources
    - DSM Supply Curves

May 23, 2008

- Proposed Oregon Public Utility Commission IRP guidelines on CO2 risk
- Range and timing of CO2 costs represented in the IRP
- Overview of the IPM (Integrated Planning Model) and usage for the IRP
- Overview of the EPRI study on CO2 policy impacts on western power markets

June 26, 2008

- Long-Term Load Forecast
  - Overview of the June 2008 Long Term Load Forecast
  - Total Company Profile
    - Forecast summary and Growth rate comparisons
    - Energy by State and Energy by Class
  - Rocky Mountain Power
    - Energy by Class
    - Utah, Wyoming, Idaho
  - Pacific Power
    - Energy by Class
    - Oregon, Washington, California
  - Risks to the Forecast
- Load and Resource Balance
- Update on portfolio development cases and modeling process

ITRON Agenda

- Modeling weather response using multi-part slopes and load research data
- Defining daily normal weather for weather normalization of energy
- Overview of the Statistically Adjusted End Use (SAE) approach
- Overview of sales models
- Overview of peak models and normal peak producing weather
- Overview of typical weather scenarios and hourly model forecasts

November 12, 2008 (Conference Call)

- IRP/ Business Plan Alignment
- IRP Development Status and Schedule
- Load Forecast

December 18, 2008

- Updated Schedule
- Updated Load Forecast
- Capacity Load and Resource Balance
- Portfolio Modeling Set-up
- Portfolio Development Results

Handout – Portfolio Development Results Package

January 7, 2009

(Repeat of 12/18/08 for Washington / Idaho participants that missed the earlier meeting)

- Updated Schedule
- Updated Load Forecast
- Capacity Load and Resource Balance
- Portfolio Modeling Set-up
- Portfolio Development Results

Handout – Portfolio Development Results Package

February 2, 2009

- Cover questions on portfolio development
- Stochastic simulation and top-performing portfolio selection approach
- Stochastic simulation results
    - Alternative capacity planning reserve margin analysis
- Portfolio ranking and preference scores
- Preferred portfolio selection
    - Scenario risk analysis

March 11, 2009 (Conference Call)

- IRP Schedule

March 19, 2009 (Conference Call) Utah Parties

- IRP Filing Extension

State Meetings

April 9, 2008 (Utah)

- DSM and enabling technologies
- Range of resource options
- Renewable energy resource analysis
    - Bramble (SB 202) renewables act and other renewable portfolio standards
    - Wind integration
    - Optimal wind amount under stochastic analysis
- Feedback on IRP/Business Plan Improvement Paper (distributed via email on 3/7/08)
- Load forecast

April 10, 2008 (Wyoming)

- DSM and enabling technologies
- Range of resource options
- Renewable energy resource analysis
- Feedback on IRP/Business Plan Improvement Paper (distributed via email on 3/7/08)
- Load forecast
- Planning reserve margin studies
- Regional capacity adequacy/market depth
- Environmental policy
    - CO2 costs/regulations
    - Other environmental externalities
- Other miscellaneous issues

April 21, 2008 (Oregon / California)

- DSM
- Range of supply-side resource options
- Feedback on the IRP/Business Plan improvement paper (distributed via email on 3/7/08)
- Impacts of the Oregon Commission 2008 IRP acknowledgment order
- Renewable energy resource analysis
- Planning reserve margin
- Environmental policy
    - Pending IRP environmental cost guideline no. 8 (UM 1302)
    - CO2 costs/regulations
- Load forecast
- Other miscellaneous issues

April 22, 2008 (Washington)

- DSM
- Range of supply-side resource options
- Feedback on the IRP/Business Plan improvement paper (originally distributed via email on 3/7/08)
- Renewable energy resource analysis and Renewable Portfolio Standards
- Planning reserve margin
- Environmental policy
- Load forecast
- Other miscellaneous issues

April 23, 2008 (Idaho)

- DSM
- Range of supply-side resource options
- Feedback on the IRP/Business Plan improvement paper (originally distributed via email on 3/7/08)
- Environmental/renewable regulatory resource constraints
- Planning reserve margin
- Load forecast
- Other miscellaneous issues

May 14, 2008 (Utah)

- Planning reserve margin studies
- Regional capacity adequacy/market depth
- Hydro capacity assumptions/sensitivity analysis
- Environmental policy
    - CO_2 costs/regulations
    - Other environmental externalities
- Other miscellaneous issues

PARKING LOT ISSUES

During the course of the public input meetings, certain concerns or questions needed additional follow-up from PacifiCorp. These questions or issues were taken off-line, addressed at a subsequent public input meeting or workshop, or assembled into a "parking lot" and responded to via a parking lot response document that is emailed to IRP participants. A number of public participants recommended that responses to individual information requests made through the IRP email "mailbox" or other means be made available to all IRP participants. PacifiCorp is investigating a process for doing do that is least burdensome to the company.

PUBLIC REVIEW OF IRP DRAFT DOCUMENT

PacifiCorp distributed the draft version of the IRP document on April 8, 2009, for public review, and requested written comments by May 6, 2009. Parties that submitted comments include:

- Renewable Northwest Project
- Oregon Department of Energy
- Public Utility Commission of Oregon Staff
- Washington Utilities and Transportation Commission Staff
- Utah Association of Energy Users (UAE)

In addition to these comments, a number of Utah parties submitted data requests prior to the filing of the final IRP document under the Utah commission's 2008 IRP acknowledgment docket (Docket No. 09-2035-01) established on April 27, 2009. These parties included the Utah Department of Public Utilities, the Utah Office of Consumer Services (formerly the Utah Committee of Consumer Services), Utah Association of Energy Users, and Utah Clean Energy.

Clarifications and information requested through the written comments and data requests were incorporated in the final version of the IRP to the extent that PacifiCorp had time to do so.

CONTACT INFORMATION

PacifiCorp's IRP internet website contains many of the documents and presentations that support the 2003, 2004, 2007 and 2008 Integrated Resource Plans. To access it, please visit the company's website at http://www.PacifiCorp.com , click on the menu "News & Info" and select "Integrated Resource Planning".

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

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APPENDIX E – STATE LOAD FORECAST

LOAD FORECAST STATE LEVEL SUMMARIES

This section provides state-level forecasted retail sales summaries. The tables below show retail sales values after the load reduction impacts of Class 2 DSM programs included in the 2008 IRP preferred portfolio are deducted. For purposes of the 2008 IRP this version of the data is known as “Post-DSM”. Chapter 5 provides the forecast information for each state and the system as a whole by year for 2009 through 2018 before Class 2 DSM load reductions are applied.

State Summaries

Oregon

Table E.1 summarizes Oregon state forecasted sales growth by customer class.

Table E.1 – Forecasted Sales Growth in Oregon

Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	5,401	4,819	2,781	266	38	0	**13,304**
2010	5,439	4,836	2,816	265	37	0	**13,393**
2011	5,445	4,849	2,816	265	37	0	**13,413**
2012	5,476	4,872	2,853	265	37	0	**13,504**
2013	5,435	4,892	2,891	265	37	0	**13,520**
2014	5,413	4,924	2,915	265	37	0	**13,554**
2015	5,390	4,955	2,936	265	37	0	**13,583**
2016	5,388	4,999	2,961	265	37	0	**13,651**
2017	5,351	5,016	2,980	265	37	0	**13,651**
2018	5,376	5,040	3,000	265	37	0	**13,718**
Average Annual Growth Rate							
2009-2018	(0.1)%	0.5%	0.8%	(0.0)%	(0.1)%	N/A	**0.3%**

The forecast of residential sales is expected to grow at a slower rate of 0.9% annually compared to average annual growth rate of around 2% experienced past five years. This slow down is mainly due to housing market slowdown and impact of worsening economic conditions. Population growth is expected to continue in the service area, which is driving some of the growth, while usage per customer in the residential class is expected to decline due to economic slowdown during earlier years. Starting with 2012, use per customer is expected to decline mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other conservation programs.

Over the first two years of forecast horizon, forecasted commercial class sales are projected to grow at a slower average annual growth rate of 1.3% compared to historical periods due to the impact of worsening economic conditions. Educational, health service, and government related commercial activity are only sectors expected to still grow during the next two years. During the remaining years of the forecast horizon, commercial sales are expected to grow at a higher average annual rate of 1.7%, which is similar to the average growth rate experienced historically. Usage per customer is projected to decline slightly due to increased equipment efficiency.

Forecasted industrial class sales are projected to decline at an average annual rate of 3.2% during 2009 and 2010 due to impacts of the housing market slowdown and current economic recession affecting mostly wood products and semi-conductor manufacturing. Starting with 2011, industrial sales is expected to grow again at an average annual growth rate of 1.7% reflecting recovery in special food processing and wood products sector, along with continued diversification in the manufacturing base in the state.

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

Washington

Table E.2 summarizes Washington state forecasted sales growth by customer class.

Table E.2 – Forecasted Retail Sales Growth in Washington

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	1,556	1,379	806	159	10	0	**3,910**
2010	1,554	1,382	810	158	10	0	**3,915**
2011	1,559	1,388	807	158	10	0	**3,922**
2012	1,571	1,398	809	158	10	0	**3,947**
2013	1,564	1,408	812	158	10	0	**3,952**
2014	1,562	1,420	815	158	10	0	**3,965**
2015	1,561	1,432	819	158	10	0	**3,980**
2016	1,567	1,448	823	158	10	0	**4,006**
2017	1,564	1,458	826	158	10	0	**4,015**
2018	1,574	1,465	827	158	10	0	**4,035**
Average Annual Growth Rate							
2009-2018	0.1%	0.7%	0.3%	(0.0)%	0.1%	N/A	**0.4%**

The forecast of residential sales is expected to grow at a slower average annual growth rate of 0.4% compared to recent historical growth rates of around 1% due to the impact of housing market slowdown and economic recession. The slight growth in residential class sales is due to continuing customer growth driven by population growth and household formation in the PacifiCorp's service area. Usage per customer is expected to decrease slightly during the early years due to worsening economic conditions. Starting with 2012, use per customer is expected to decline mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation.

Over the first two years of forecast horizon, forecasted commercial class sales are projected to grow at a slower rate of 0.8% compared to historical periods due to the impact of current economic recession. Beyond 2010, commercial sales are expected to grow at a higher average annual rate of 1.5%, which is close to average annual growth rate experienced historically.

The industrial class sales are projected to decline for the first four years of forecast horizon mainly due to housing market slowdown affecting wood products sector. For the remaining part of the forecast period industrial sales are expected to grow slightly reflecting recovery in wood products and food processing sectors.

California

Table E.3 summarizes California state forecasted sales growth by customer class.

Table E.3 – Forecasted Retail Sales Growth in California

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	387	298	51	98	2.49	0	**838**
2010	389	301	51	98	2.47	0	**841**
2011	391	308	71	98	2.47	0	**871**
2012	396	319	81	98	2.48	0	**897**
2013	394	327	88	98	2.47	0	**910**
2014	395	337	91	98	2.47	0	**924**
2015	397	348	91	98	2.47	0	**936**
2016	399	359	91	98	2.48	0	**950**
2017	400	368	91	98	2.47	0	**960**
2018	405	378	91	98	2.47	0	**975**
Average Annual Growth Rate							
2009-2018	0.5%	2.7%	6.6%	0.0%	(0.1)%	N/A	**1.7%**

The rate of growth in residential class sales is driven, by the continuing growth in population in this part of PacifiCorp's service area. Usage per customer in the residential class is expected to decline due to increasing adoption of more efficient appliances and the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation effective in 2012. .

The continuing population growth also affects sales in the commercial sector through continued commercial customer growth. Additionally, commercial usage per customer is increasing due to greater square footage per building in new construction, increases in the number of offices, and the increasing use of office equipment in all commercial structures. However, some of this growth is being offset from increased equipment efficiency over the forecast horizon.

Declines over the decade in the lumber and wood product industries production resulted in an overall decline in the industrial sales; however, there are indications that this trend has ended and growth in other businesses are expected to continue. During first four years of forecast horizon, industrial sales are expected to grow due to the addition of new industrial customers. For the remaining years sales are expected to remain flat.

Utah

Table E.4 summarizes Utah state forecasted sales growth by customer class.

Table E.4 – Forecasted Retail Sales Growth in Utah

	Retail Sales – Gigawatt Hour (GWh)						
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	6,556	7,410	7,337	189	76	437	**22,005**
2010	6,687	7,589	7,364	189	76	436	**22,341**
2011	6,807	7,826	7,700	189	76	436	**23,034**
2012	6,965	8,074	7,905	189	76	437	**23,646**
2013	6,978	8,271	8,241	189	76	436	**24,192**
2014	7,048	8,528	8,626	189	76	436	**24,904**
2015	7,123	8,788	9,007	189	76	436	**25,618**
2016	7,217	9,064	9,251	189	76	437	**26,234**
2017	7,278	9,300	9,331	189	76	436	**26,610**
2018	7,440	9,564	9,414	189	76	436	**27,119**
	Average Annual Growth Rate						
2009-2018	1.4%	2.9%	2.8%	0.0%	0.0%	0.0%	**2.3%**

Utah continues to see natural population growth that is faster than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of in-migration. However, the rate of population growth is expected to be lower in the coming decade as in-migration into the state slows down. Over the forecast horizon, residential sales are expected to grow at a slower rate of 1.7% compared to what has been experienced historically due to slow down in-migration and housing market slowdown in near-term. Usage per customer in the residential class is expected to decline due to recent economic recession during early part of the forecast horizon. Beyond 2012, the decline in use per customer is driven by the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The continuing population growth also affects sales in the commercial sector by continued commercial customer growth. Usage per customer is projected to decline due to recent economic recession during early part of the forecast horizon, and starts increasing again during later years with new construction having greater square footage per building and increasing usage of office equipment. However, some of this growth is being offset from equipment efficiency gains over the forecast horizon.

The industrial class has been experiencing significant industrial diversification in the state and will continue to cause sales growth in the sector. Utah has a strategic location in the western half of the United States, which provides easy access into many regional markets. The industrial base has become more linked to the region and is less dependent on the natural resource base within the state. This provides a strong foundation for continued growth into the future. For the first two years of forecast horizon, industrial sales are expected grow at a much slower rate of 0.6% annually compared to historical average annual growth rate of 3.5% experienced over the past five years. Expansions by mining and natural resources are projected to slowdown with continuing downturn in manufacturing. Starting 2011, industrial sales are expected to grow again at higher rates similar to what was experienced historically, reflecting expected improvement in overall economic conditions.

Idaho

Table E.5 summarizes Idaho state forecasted sales growth by customer class.

Table E.5 – Forecasted Retail Sales Growth in Idaho

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	711	409	1,637	616	2.47	0	**3,375**
2010	719	414	1,648	615	2.51	0	**3,400**
2011	731	422	1,651	615	2.55	0	**3,421**
2012	747	432	1,657	615	2.59	0	**3,454**
2013	749	438	1,772	615	2.64	0	**3,577**
2014	756	450	1,856	615	2.68	0	**3,681**
2015	764	462	1,863	615	2.74	0	**3,707**
2016	776	475	1,871	615	2.80	0	**3,740**
2017	784	485	1,877	615	2.81	0	**3,764**
2018	802	497	1,884	615	2.87	0	**3,800**
Average Annual Growth Rate							
2009-2018	1.3%	2.2%	1.6%	(0.0)%	1.7%	N/A	**1.3%**

The recent migration to Idaho has led the residential sales to grow at an average annual growth rate of around 4.0% during past five years. Over the forecast horizon, the residential sales are still projected to grow but at a slower rate of 1.5% annually compared to historical periods due to expected slow-down in in-migration. Usage per customer is expected to decline mainly due to recent economic recession during earlier years, and due to increased energy efficiency and conservation programs for the later years.

The growth rate for commercial class sales is expected to continue to be strong due to customer growth in response to the increasing residential customer growth resulting further growth in service sectors such as education and health care services. Usage per customer is projected to increase, which has been influenced in part by new construction,, increased air conditioning saturation, office equipment, and exterior lighting. However, this growth is somewhat offset by equipment efficiency gains over the forecast horizon.

Industrial sales are expected to decline in 2009 due the impact of worsening economic conditions, and remain flat until the end of 2012. Industrial sales are expected to increase again in 2013 due to some new customers in the service area.

Wyoming

Table E.6 summarizes Wyoming state forecasted sales growth by customer class.

Table E.6 – Forecasted Retail Sales Growth in Wyoming

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2009	1,054	1,493	6,898	21	12	0	**9,478**
2010	1,079	1,510	7,296	21	11	0	**9,918**

Retail Sales – Gigawatt Hour (GWh)							
	Residential	**Commercial**	**Industrial**	**Irrigation**	**Lighting**	**Other**	**Total**
2011	1,098	1,537	7,742	21	11	0	**10,410**
2012	1,122	1,569	8,283	22	11	0	**11,008**
2013	1,132	1,597	8,617	22	11	0	**11,379**
2014	1,148	1,629	8,951	23	11	0	**11,762**
2015	1,166	1,660	9,276	23	11	0	**12,138**
2016	1,193	1,698	9,632	24	11	0	**12,559**
2017	1,217	1,729	9,903	24	11	0	**12,884**
2018	1,258	1,763	10,168	25	11	0	**13,225**
Average Annual Growth Rate							
2009-2018	2.0%	1.9%	4.4%	2.2%	(0.5)%	N/A	**3.8%**

Residential sales is expected to grow at a slower average annual rate of 0.8%, compared to an average annual growth rate of around 3% experienced during past five years. Population growth is still expected to continue in the service area, which causes some of the sales growth. Usage per customer in the residential class is expected to decline due to recent economic recession during earlier years. During later years of the forecast horizon, use per customer is expected to decline due to impact of long-term lighting efficiency gains resulting from the 2007 federal energy legislation, effective in 2012.

Over the forecast horizon, commercial class sales are also projected to grow at a slower annual growth rate of 1.3% compared to historical periods. Sales growth is driven mainly by the customer growth in response to still continuing residential customer growth and the growth of the office sector.

Wyoming industrial sales growth, driven by expansion in oil and gas extraction industries, is expected to continue, but at a much reduced rate due to declines in energy prices and worsening economic conditions. Continuing growth in industrial customers in the service area also contributes to the load growth in the residential and commercial customer sectors.

FEBRUARY 2009 LOAD FORECAST UPDATE

PacifiCorp prepared a new load forecast in February 2009 after reviewing actual loads through January 2009. With continuing worsening economic conditions, the Company reviewed the loads in PacifiCorp's service territories, and revised the forecast accordingly to reflect the latest impact on loads and latest forecast of economic variables. Below are the capacity and energy tables similar to those found in Chapter 5. These forecasts are net of DSM-related load reductions.

February 2009 Energy Forecast

Table E.7 – February 2009 Annual Load Growth forecasted in Megawatt-hours

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**60,513,585**	14,717,735	4,339,279	966,290	24,066,263	10,167,695	3,718,077	2,538,247
2010	**61,603,833**	14,810,829	4,344,912	966,218	24,522,312	10,646,811	3,750,820	2,561,930
2011	**63,263,930**	14,921,509	4,371,402	1,004,954	25,404,577	11,188,878	3,785,957	2,586,655
2012	**65,029,943**	15,115,696	4,417,268	1,037,281	26,168,642	11,845,914	3,829,464	2,615,678
2013	**66,466,245**	15,159,619	4,424,099	1,055,642	26,884,446	12,253,897	3,974,809	2,713,732
2014	**67,979,096**	15,223,467	4,443,316	1,071,104	27,682,221	12,674,296	4,088,986	2,795,706
2015	**69,346,652**	15,283,484	4,463,835	1,084,175	28,492,384	13,088,772	4,118,092	2,815,910
2016	**70,712,194**	15,382,412	4,496,642	1,100,268	29,188,167	13,549,959	4,154,171	2,840,577
2017	**71,559,345**	15,402,000	4,506,713	1,109,880	29,596,661	13,908,106	4,178,291	2,857,694
2018	**72,717,605**	15,513,152	4,542,282	1,126,645	30,141,988	14,293,815	4,215,982	2,883,742
Annual Average Growth Rate								
2009-18	**2.1%**	0.6%	0.5%	1.7%	2.5%	3.9%	1.4%	1.4%
2018-28	**1.1%**	0.5%	0.6%	1.3%	1.5%	1.3%	0.8%	0.8%
2009-28	**1.6%**	0.5%	0.6%	1.5%	2.0%	2.5%	1.1%	1.1%

February 2009 System-Wide Coincident Peak Load Forecast

Table E.8 – February 2009 Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**9,941**	2,362	728	158	4,440	1,268	625	361
2010	**10,161**	2,395	737	158	4,546	1,307	649	368
2011	**10,481**	2,419	746	166	4,710	1,371	674	395
2012	**10,805**	2,446	782	172	4,838	1,439	705	423
2013	**11,024**	2,462	763	176	4,968	1,490	737	428
2014	**11,179**	2,486	775	177	5,126	1,538	683	395
2015	**11,425**	2,501	783	180	5,262	1,585	708	406
2016	**11,690**	2,517	790	183	5,382	1,635	746	436
2017	**11,876**	2,530	798	189	5,478	1,678	759	443
2018	**12,110**	2,551	837	189	5,581	1,722	770	461

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
Annual Average Growth Rate								
2009-2018	2.2%	0.9%	1.6%	2.0%	2.6%	3.5%	2.3%	2.8%
2018-2028	1.2%	0.7%	0.8%	1.5%	1.6%	1.3%	0.7%	0.4%
2009-2028	1.7%	0.8%	1.1%	1.7%	2.0%	2.3%	1.5%	1.5%

APPENDIX F – WIND INTEGRATION COSTS AND CAPACITY PLANNING CONTRIBUTIONS

This appendix summarizes the results of PacifiCorp's latest wind integration cost analysis, which will continue to be refined and expanded. This appendix also presents updated wind capacity contribution values using a statistical estimation methodology that was applied for the first time in the Company's 2007 IRP.

For the wind integration cost study, PacifiCorp developed a methodology to support the costs associated with resource portfolio analysis for the IRP as well as costs used in the evaluation of cost effective renewable resources. This approach decomposes the estimation of inter-hour (hour to hour) and intra-hour (within the hour) costs to integrate intermittent renewable resources. For inter-hour costs, these components include day-ahead and hour-ahead wind forecast variability, or what was referred to as system balancing costs in the 2007 IRP.[2] For intra-hour costs, the components include actual forecast variation, "regulation up" requirements, and "regulation down" requirements. These latter costs pertain to operational assessment and planning of wind variability down to 10-minute intervals or less. In addition to this cost breakdown, PacifiCorp reports integration costs for wind added in the PacifiCorp eastern balancing authority area (PACE), the PacifiCorp west balancing authority area (PACW), and a system weighted-average based on installed capacity in each control area.

The wind integration cost section first provides background on these cost components and then describes the estimation methodologies and cost results. Study caveats and areas for further research are also summarized. The costs results are expressed as a function of the amount and timing of wind included in the 2008 IRP preferred portfolio as well as existing wind (Table F.1). The section concludes with a discussion on future tools, approaches, and external coordination opportunities that PacifiCorp is actively considering or exploring to address the consequences of adding large quantities of wind.

Table F.1 – 2008 IRP Preferred Portfolio Wind Resource Additions by Year

Year	Capacity Additions (MW)	Capacity Factor	Region
Existing and Planned through 2010	1,284	--	System
2011	100	29%	Walla Walla
2011	100	29%	Yakima
2012	100	35%	Southwest Wyoming
2013	100	35%	Southwest Wyoming
2014	100	35%	Aeolus Wyoming
2015	150	35%	Aeolus Wyoming
2016	100	35%	Aeolus Wyoming
2017	100	35%	Southwest Wyoming

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[2] PacifiCorp, 2007 Integrated Resource Plan, Appendix J, pp. 193-4.

Year	Capacity Additions (MW)	Capacity Factor	Region
2018	50	35%	Southwest Wyoming
2019	200	35%	Southwest Wyoming
2020	200	35%	Southwest Wyoming
2021	150	35%	Southwest Wyoming
TOTAL	2,734		

Due to a number of project schedules, this wind study was not completed in time to be incorporated into the 2008 IRP portfolio modeling. As discussed in Chapter 7 of Volume 1, a value of $11.75/MWh—based on Portland General Electric Company's latest wind integration study—was used for IRP capacity expansion optimization modeling purposes. While the Company acknowledged the differences between the PacifiCorp and PGE systems and the caveats associated with the PGE study, PacifiCorp believed that the PGE value represented a reasonable proxy until its own study could be completed. If the wind integration cost study yields a significantly different total value, the Company commits to perform a sensitivity study with the System Optimizer capacity expansion model and the 2008 IRP preferred portfolio modeling assumptions to determine the wind resource selection impact of the updated cost value.

WIND INTEGRATION COSTS

Background

In power planning and dispatch, any period in which load or generation varies from a steady value results in an increased cost for the utility to balance out this variation. Variations in the load and wind generation forecasts are managed with balancing activities. Once the hour-ahead schedule is given to the real-time staff, actual variation in load and wind generation within the hour is balanced using system generation resources. Current balancing activities treat wind forecast variations similarly to load forecast deviation; however, special attention is required for the greater percentage variability and near-term volume growth of wind generation.

The components of wind variability which give rise to integration costs can be divided into two groups: inter-hour and intra-hour. The inter-hour components of wind variability are:

- Day-ahead forecast variation: deviation of the long-term wind forecast (prior energy expectations) to the day-ahead forecast for the day prior to power delivery.
- Hour-ahead forecast variation: deviation of hour-ahead forecast from day-ahead forecast for the hour prior to delivery.

The rebalancing or closure of open positions generated as new load and wind forecast data becomes available requires the payment of transaction costs.

The other set of costs to be considered is associated with the intra-hour (within the hour) components of wind variability:

- Actual forecast variation: deviation of actual hourly average energy from the hour-ahead forecast,
- Regulate down: deviation of hourly maximum energy from the energy at the beginning of the hour, measured with ten minute granularity,
- Regulate up: deviation of hourly minimum energy from the energy at the beginning of the hour, measured with ten minute granularity,
- Automatic Generation Control (AGC): fine scale variation of energy over a one to two minute time scale.

These intra-hour factors require the holding of additional reserves above the standard requirement of 5 percent on wind generation. Due to the small impact, yet large analytical requirement, to determine reserves for AGC, this cost component is not addressed in the wind integration study; however, this issue may be pursued in the future as the company gains more experience in this area.

These inter- and intra-hour factors do not include long-term shaping effects. While benefits or costs may arise due to the hourly difference between expected future energy in moving from a flat-dispatched unit such as geothermal to a shaped profile unit such as wind, on a longer-term view, these differences are only the effect of different hourly prices or expected value on the forecasted future energy; therefore, no actual costs are incurred from balancing a new long-term wind pattern with system resource redispatch.

Determination of Incremental Reserve ("Intra-Hour") Requirements

Before all reserve costs can be estimated, the megawatt (MW) quantity of reserves required to maintain system reliability as additional wind in the Eastern and Western balancing authority areas of PacifiCorp's service region must be calculated. In previous wind integration studies, PacifiCorp has not captured the increased load-following reserve requirements caused by wind forecast error within the hour. Increasing the magnitude of wind resources on the system results in an increased reserve requirement due to the fact that wind forecasts are inherently inaccurate, particularly at within-hour granularity. Intra-hour wind variability requires the dispatch of existing units to balance the system as there is no intra-hour market.

Actual Variation

The deviation of the actual hourly average energy from the hour-ahead forecast can be computed given the historical hour-ahead wind generation forecast and actual hourly energy values. This produces statistical hourly distributions of the forecast versus actual energy. If this was the only source of the intra-hour uncertainty, the quantities of reserves may be easier to estimate by taking the 97.5th percentile of the variation distribution which represents two standard deviations of forecast error and the approximate PacifiCorp performance under Control Performance Standard II (CPS II)[3]). Reporting levels of reserves required with a 97.5% confidence interval adds an important reliability dimension to the calculation. While actual day-to-day balancing operations may require less reserves than suggested in this study, attention to tail events is an important consideration for overall system reliability. Additional considerations include the correlation

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[3] The CPS II standard refers to the compliance bounds for the 10-minute average of the Area Control Error.

between forecast error and two additional sources of intra-hour uncertainty: "regulate down" and "regulate up".

Regulate Down

For the purposes of this study, regulate down is the difference between the maximum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves up within an hour, other generation resources are required to reduce their output to compensate for this intra-hour energy deviation. The analysis of 10-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and the ten-minute period of maximum energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp's CPS II standard.

Regulate Up

For the purposes of this study, regulate up is the difference between the minimum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves down within an hour, other resources on the system are required to increase output to compensate for this intra-hour energy deviation. The analysis of 10-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and minimum energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp's CPS II standard.

These three intra-hour factors for different locations are not independent of each other and tend to exhibit some positive and negative correlations that are taken into account when measuring the standard deviation of the simultaneous and combined effect of these factors. Before estimating the total reserves requirement for intra-hour integration, correlations are estimated and applied to determine the total combined uncertainty on a regional level. Two standard deviations for the total probability distribution allowed for computation of reserves associated with all intra-hour factors in the Eastern and Western control areas.

System Balancing ("Inter-Hour") Cost Calculation

The shape of a wind energy delivery pattern is different than the delivery patterns of other generation resources. The wind is intermittent and variable, so a wind pattern that is input as a forecast of expected generation differs considerably from the actual generation delivered. Alternatively, a dispatchable resource, like a CCCT, does maintain a flat schedule of energy delivery so generation units on the system do not have to redispatch and balancing activities do not have to occur to compensate for a block of flat energy. When a short-term wind forecast is created and compared to a longer-term wind energy expectation, balancing activities may have to occur to balance the deviation between the wind forecasts and realized output.

Day-ahead Variation

Because a day-ahead forecast of hourly wind energy always differs from the expected future energy level by some amount, the ideal of delivering a balanced energy profile on a day-ahead basis requires some adjustment in the energy position via transactional balancing. While deviation from a perfectly balanced schedule is normal, estimation of the impacts are assumed to be eliminated by balancing activities to the extent possible.

Fixing the imbalance in real-time is generally more expensive and, to this end, this study assumes that all forecast imbalances are addressed in the day-ahead market. This is limited by the size and availability of standard 25 MW blocks for standard 16-hour or 8-hour (on-peak and off-peak) delivery patterns. PacifiCorp incurs transaction costs every time it trades a block of 25 MW. These transaction costs may vary depending on the time of day and location and are currently estimated to be about $0.50 per MWh over market for purchases to cover a shortfall in forecast, and under market for sales to cover a forecast excess during most transactional hours. This internal assumption is generally accepted by balancing staff and is consistent with the assumption used in Portland General Electric's wind integration study. Given the hourly difference between the long-term expected wind generation and the historical wind generation forecasts at the day-ahead horizon, these costs may be estimated.

To calculate the transactional costs associated with balancing the hourly long-term expected wind generation to the hourly day-ahead wind schedule, the variation was calculated as the absolute value of the difference between the two forecasts. For October 2008 through April 2009, a sample week of hourly data from all existing wind plants on the system (for which data was available) was chosen for each month[4]. The distinction of costs between the Eastern and Western side of the system is reflective of different degrees of forecast accuracy. The existing data was scaled up to reflect the planned East and West additions to the system, 200 and 1,250 MW, respectively, for a total of 773 MW on the West and 1,784 MW on the East. The total deviation was found for each day for both heavy load and light load hours.

For example, on Day 1, the deviation for all heavy-load hours was added. The same was done for light-load hours. The resulting totals were rounded up to the nearest 25 MW increment to reflect actual transaction sizes available in the day-ahead market. The total daily variation was added up for each sample week and multiplied by an estimated bid-ask spread of $0.50 per MWh. PacifiCorp's front office provided this bid-ask spread estimate. The total transaction costs incurred for all sample weeks was divided by the total MWh of long-term expected generation for the same sample weeks and presented on a $/expected MWh basis provided in Table F.2. Transaction costs in the table below are lower in the Eastern control area and may be the result of more accurate forecasting, a more uniform wind pattern, and higher locational diversity.

Table F.2 – Wind Inter-hour Day-Ahead Balancing Transaction Costs

System	Wind Expected to Day-Ahead ($/Expected MWh)
West	$0.41
East	$0.23

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[4] This period was chosen due to limited data availability.

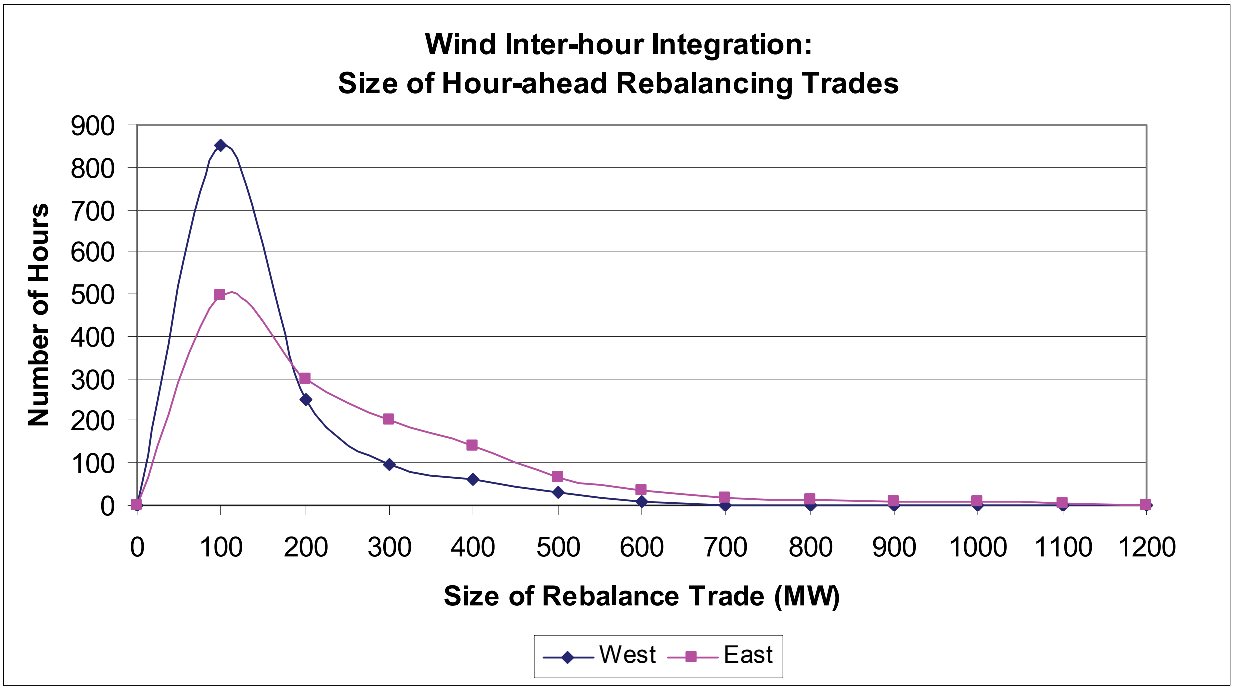
Hour-ahead variation

Similar to the day-ahead variation, the rebalancing of energy to close open positions due to the change in forecasted wind energy from the day-ahead schedule to the hour-ahead schedule also adds transaction costs. Hour-ahead transactions assume transactions in 1 MW increments, but transactions costs are up to twenty-five percent of the per-MWh energy costs. The precise percentage depends on then–current market conditions and the amount of energy traded.

In order to derive the hour-ahead forecast used by real-time for scheduling, a persistence methodology was used. When the real-time traders schedule wind for the upcoming hour, it is assumed that the actual wind generation level from the previous hour will persist for the next hour. In this study, the hour-ahead schedule was based on persistence. The existing October 2008 through April 2009 data was scaled up to reflect the planned East and West additions to the system, 200 and 1,250 MW, respectively, for a total of 773 MW on the West and 1,784 MW on the East. The total deviation was found for each day for both heavy load and light load hours.

The day-ahead to hour-ahead balancing transaction costs were calculated in largely the same fashion with the exception of the bid-ask spread used. Transactions undertaken to correct an imbalance, due to variations between the day-ahead and hour-ahead forecast, are of higher cost, which is dependent upon the quantity of power needed and market conditions. Figure F.1 shows the hourly frequency of various imbalance sizes based on 1,300 hourly deviations, which is constitutes the total number of sample hours.

Figure F.1 –Hour-Ahead Variation Frequency Distribution



It is also generally accepted in the hour-ahead market that, as the size of the transaction increases, the costs associated with transactions increases. Based on the frequency distribution above, a smaller cost is required for transactions of about 50 MW, which are transacted much more frequently. The distribution also indicates that, in general, transaction costs on the west portion of the system will be higher due to lower forecast accuracy. Specific transaction assumptions are listed in Table F.3.

Table F.3 – Inter-hour Hour-Ahead Balancing Transaction Cost Ranges

Trade Size (MW)		Transaction Cost (Bid-ask) Percentage by Region	
Lower Bound	**Upper Bound**	**West**	**East**
0	100	5%	5%
101	200	10%	10%
201	1,000	25%	15%

Table F.3 indicates that as more wind projects are added to the system, forecast improvements are necessary in order to prevent large variations which come with a higher market transaction cost. Consider, on an average basis, if a 100 MW wind project is added to the system, the shape of the distribution of the size of hourly errors will be about the same. As the distribution of error increases in a linear fashion, the cost associated with rebalancing does not. Since costs are greater as the size of transactions increases, the distribution of errors may increase on a linear basis, but costs will increase faster.

Once the hourly variance from the day-ahead forecast to the hour-ahead forecast has been calculated, the specific hourly variance is applied to the corresponding hourly real-time price from an independent energy information company that publishes hourly wholesale power indices. For PACE, Four Corners was used and for PACW, Mid-Columbia was used. The size of the variance determines the transaction cost, which is the product of the hourly price and the corresponding variance percentage. In Table F.4 below, the day-ahead to hour-ahead transaction cost is presented along with the total inter-hour cost for the east and west balancing authority areas.

Table F.4 – Wind Inter-hour Hour-Ahead Balancing Transaction Costs

System	Wind Expected to Day-Ahead ($/Expected MWh)	Wind Day-Ahead to Hour-Ahead ($/Expected MWh)[5]	Total Wind Inter-hour ($/Expected MWh)
West	$0.41	$2.80	$3.21
East	$0.23	$1.89	$2.12

<u>Determination of Incremental Reserve (“Intra-Hour”) Requirements</u>

The indicated MW of additional reserves needed to balance the total intra-hour wind generation variations on PacifiCorp’s system due to incremental wind addition is unique to each region of

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[5] Values expressed are representative of the average cost to transact for the October 2008 through April 2009 period.

PacifiCorp's system. These values were derived by multiplying the within-hour standard deviation from all wind projects in each of the three regions in this study by a Z score of 1.96 (which is representative of the 97.5% confidence interval and PacifiCorp's CPS II requirement) and is inclusive of all three sources of inter-hour variation discussed. Table F.5 presents the corresponding reserve volumes for each region in the system and reflects fixed volumes of new annual wind projects spread through 2021 consistent with the company's general long-term wind acquisition strategy.

Table F.5 – Total Wind System Intra-hour Reserve Requirement (MW)

Resources	Capacity Additions	Total Reserve Requirement	Incremental Increase	Cumulative Increase
Existing and Planned through 2010	1,284	295.4		
2011	200	312.7	17.3	17.3
2012	100	331.2	18.5	35.8
2013	100	339.1	7.9	43.7
2014	100	349.1	9.9	53.6
2015	150	367.8	18.8	72.4
2016	100	380.5	12.6	85.0
2017	100	385.1	4.6	89.7
2018	50	402.0	16.9	106.6
2019	200	420.9	18.9	125.5
2020	200	433.2	12.3	137.7
2021	150	452.9	19.7	157.5

Incremental Reserve ("Intra-Hour") Cost Calculation

The previous section described the calculation of MW quantities associated with adding wind generation resources. In this section, the calculation of the cost associated with wind additions is described.

As the company installs larger volumes of wind resource generation, the company's cost to integrate these intermittent resources is anticipated to increase. This is because more and more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour-to-hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts often provide the needed flexibility. However, these hydro resources are not of adequate size to integrate all of the anticipated wind variability. Partially loaded gas turbines provide additional flexibility. Due to its low cost, it is economically preferable that coal is fully utilized to serve load rather than backed off to provide wind integration.

The study assumes that PacifiCorp would balance the intermittency of the wind by holding additional reserves on existing and future flexible resources. A reserve resource stack model was developed that is used to estimate both in-the-money and out-of-the-money reserve costs. The modeling of reserves added the requirements for load and reduced the requirement for hydro and contract reserves in the valuation. In-the-money reserve costs are measured by calculating market prices less the cost of thermal dispatch (fuel, variable O&M, CO_2 emission costs, and SO_2 emission costs). Out-of-the-money reserve costs are estimated by calculating the above-market operating costs of a unit dispatched at minimum capacity divided by the total amount of reserve capability available once at minimum load. The reserve requirement is then filled by the lowest cost in-the-money or out-of-the-money thermal resource considering the resource reserve capacities and unit ramp rates. PacifiCorp used market prices at Mona, Mid-Columbia, and Four Corners with the \$45 CO_2 October 2008 price curve (2013 is the assumed start of CO_2 regulation).

The wind reserve results reported in Table F.6 are at the system level and include both existing and incremental wind projects. The reserve results are levelized on a real basis (with inflation effects removed) for the study period 2009 to 2030 by dividing the reserve cost by the wind expected megawatt-hour generation. The existing reserve available data ended in April 2014 so the data was escalated using the prior three-year average. The reserve study considered heavy load and light load hour for the analysis but was limited by the wind reserves calculated on an annual basis.

Table F.6 – Costs for Wind Intra-hour Incremental Reserves

Wind Existing and Incremental Approximately (MW)	System Wind Intra-hour Reserves
2,734	\$9.40

To determine the cost impact of using a lower CO_2 cost, PacifiCorp estimated the intra-hour reserve cost assuming an \$8 CO_2 tax. The wind reserve costs dropped to \$7.51/MWh, expressed in \$2009, representing a 20-percent decline relative the cost under the \$45 CO_2 cost study. It is not necessarily true; however, that increasing the cost of CO_2 equates to a higher reserve cost. This relationship may be a function of near-term natural gas price curves.

Conclusion

The wind integration cost results are presented in Table F.7, and range from \$9.96/MWh to \$11.85/MWh for PacifiCorp's system in 2009 dollars, depending on the CO_2 tax level scenario. The inter-hour wind results were developed by weighting the PACW inter-hour wind costs by 30% (the PACW MW share of the system total) and the PACE wind costs by 70%, then adding the system wind reserves.

Table F.7 – Wind Integration Costs (2009 Dollars)

CO$_2$ Cost Scenario	System Balancing Cost (Inter-hour)			Intra-hour Cost ($/Expected MWh)	Total ($/Expected MWh)
	Expected to Day-Ahead Cost ($/Expected MWh)	Day-Ahead to Hour-Ahead Cost ($/Expected MWh)	Total Cost ($/Expected MWh)		
$8 tax	$0.28	$2.17	$2.45	$7.51	$9.96
$45 tax	$0.28	$2.17	$2.45	$9.40	$11.85

The system wind integration costs are in line with the $11.75/MWh proxy value used for 2008 IRP portfolio modeling. Consequently, PacifiCorp did not conduct a wind resource sensitivity study using PacifiCorp's updated values.

TOOLS, APPROACHES, AND EXTERNAL OPPORTUNITIES

There are a number of wind integration tools, approaches, and potential external coordination opportunities that the Company has implemented or is actively investigating. These include the following.

- **Real-Time Balancing:** PacifiCorp has significantly advanced its forecasting process. At present, forecasts in advance of real-time scheduling are done at 40 to 45-minutes prior to the delivery hour and on a persistence forecast[6]. Operational experience has shown that persistence based scheduling in real-time significantly reduces forecast error from using model-based techniques in advance of 40 to 45-minutes prior to the delivery hour.

- **Day-to-Day Balancing** - PacifiCorp has retained an external firm to prepare forecasts every six hours for the primary purpose of day-to-day balancing activities. Finding tools to enhance/improve the day-to-day forecast is likely to lead to enhanced real-time forecasting and, therefore, reduced load following reserve requirements during most hours. Specific tools that will require ongoing investigation and/or capital allocation may include: enhanced wind project status feedback (to the external forecasting contractor); on-site radar devices; and/or contracting with third parties who can provide regional real-time wind data or pooling information with other control area operators to obtain consolidated forecasts.

- **Peer Review** – PacifiCorp will consider incorporating the concept of the peer group review for evaluation of its ongoing refinement of wind integration cost estimation methods as part of the IRP public participation process. At present, the industry is suffering from the lack of standardized wind integration study methods. As a result, it is necessary to examine each such study to unravel its assumptions and methodology to be able to understand how it compares to other studies.

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[6] Persistence based scheduling is the practice of scheduling production for the next hour based on then-current production.

- **Curtailment Tools** – A number of tools exist for either curtailing wind project output during those hours where a critical need exists or limiting the impact of wind resources on the system during unusual ramping events. Such tools may include:
  - **Ramp Rate Limiters:** PacifiCorp's General Electric wind turbines in Wyoming include a ramp rate limiter option. This option enables PacifiCorp operators to set a maximum rate by which a wind project's output will change over time (MW/minute) during periods when the wind is ramping up
  - **Curtailment -** PacifiCorp's General Electric wind turbines in Wyoming include a curtailment option. This option enables PacifiCorp operators to curtail or limit the output of wind projects on short notice.
  - **Power Purchase Agreements (PPA) -** Many of PacifiCorp's PPAs include provisions enabling the Company to curtail output for certain reliability events or for other reasons. New PPAs all have such provisions. For example, PPAs entered into via the RFP process all contain such curtailment provisions. Additionally, the company will continuously review and refine PPA contractual requirements for output forecasting, outage reporting and curtailment.
  - **Large Generator Interconnection Agreements** (LGIA) – Federal Energy Regulatory Commission LGIAs all contain provisions[7] enabling the transmission provider to curtail or disconnect generation if necessary for reliability reasons.
  - **Mid-Hour Scheduling Practices** – At present, the practice of the **WECC** only compels mid-hour schedule changes when there is an "emergency" on the sink balancing authority area. PacifiCorp currently has other third Party wind generators who schedule wind generation for export out of PACW and PACE. There is no established practice compelling mid-hour schedule changes when the source balancing authority area is having an "emergency" which results in other than comparable service for point-to-point transmission customers as compared to network transmission customers. An evolution of mid-hour scheduling practices at WECC for emergencies involving wind generation could lead to a reduction in load following reserves being held. As the level of wind resources being scheduled for export out of a balancing authority area increases, the need for mid-hour schedule changes can be expected to significantly increase.
  - **Transmission Tariffs** – A variety of new tariffs and/or tariff adjustments can be expected to evolve over time:
    - **Integration Tariff:** At present, PacifiCorp does not have an integration tariff. An integration tariff may be appropriate when a transmission provider must integrate wind projects on an hourly basis that are scheduled off-system. As the demand for renewable resources continues to grow in the WECC, PacifiCorp may see a growing preponderance of interconnected wind projects being scheduled for export out of the

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[7] Appendix G to the LGIA

balancing authority area. This is the main reason that BPA created an integration tariff. Integration tariffs attempt to appropriately capture the cost of intra-hour integration costs. An integration tariff also sends an appropriate price signal to generator owners regarding the value of good forecasting.

  - **Imbalance Tariff:** PacifiCorp's imbalance tariff should be reviewed to determine if it provides an appropriate price signal to generation owners for good forecasting practices. It may be through the combination of an integration tariff and an imbalance tariff with increasing penalties that wind generation owners will have the incentive to deploy effective forecasting tools.

  - **LGIA:** It may be necessary to evolve FERC standard LGIA language to capture the forecasting diligence and curtailment flexibility required of wind resources by transmission operators who also operate as the balancing authority.

  - **Incentives**: If a transmission operator is also a regulated utility with load service obligation and is subject to RPS, it may be necessary for FERC to consider incentives for the entity who is the recipient of intermittent renewable resources (such as wind) to also be the entity responsible for providing the load-following reserves. Since RPS requirements are load-based, a fair application may be to require the load (i.e., sink control area) receiving the intermittent resource to either provide the load-following reserves necessary or telemeter the resource into its own balancing authority area.

- **Wind-only Balancing Authorities** – Some entities in the Pacific Northwest appear willing to pursue formation of a wind-only balancing authority. Here, an entity would contribute their wind resource into the balancing authority, schedule out of the balancing authority, and be responsible for their pro-rata share of intra-hour integration costs. Any entity in the market would be eligible to bid in load-following services to perform the balancing. This effort is only at the conceptual stage.

- **Reserve Sharing:** The creation of bilateral arrangements in addition to that found in the NWWP.

- **Balancing Market**: The creation of a 10-minute balancing market would provide accurate and appropriate price signals to owners of wind generation and would most likely be incorporated into integration tariffs in lieu of capacity costs.

- **ACE Pooling:** ACE pooling is yet another way to spread or socialize volatility associated with wind resources across multiple balancing authority areas.

- **Independent System Operator (ISO):** A reassessment of combining multiple balancing authorities.

- **Flexible Resources**: Creating more accurate forecasts, curtailing wind resources when necessary, and deploying one or more of the tools discussed above, can be expected to help optimize and minimize the amount of load-following reserves that a control area must carry to integrate wind resources. Ultimately, this will not be enough, leading to the need for significant transmission investments and/or an ISO. It is reasonable to expect that flexible resources will be required to manage the significant influx of wind resources that is likely to result from a Federal RPS, or to respond to increasing RPS standards in states like California. A significant policy issue centers on the payment for these flexible resources when they are required to maintain control area reliability. A time honored alternative is to apply the costs on a causation basis or socialize them in some fashion as deemed by the Federal Energy Regulatory Commission.

WIND CAPACITY PLANNING CONTRIBUTION

For the 2008 IRP, PacifiCorp used the Z statistic method[8] for estimating peak load capacity contributions on a monthly basis for incremental 100 MW blocks of wind capacity at each site reflected in the IRP models. This method is based on estimating the effective load carrying capability of wind. No changes to the methodology took place for the capacity contribution update; wind output data was updated based on new information obtained for resources added to PacifiCorp's system.

The results of the updated analysis as applied to the proxy (100-megawatt) wind resource options are shown in Table F.8. The July peak load carrying capability (PLCC) values are highlighted, since these are used by the capacity expansion model for determining how capacity reliability constraints are met.

Key observations from these results include the following:

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

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[8] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

Table F.8 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource by Capacity Factor	Resource Size (Nameplate MW)	Jan	Feb	Mar	Apr	May	Jun	July PLCC	Aug	Sep	Oct	Nov	Dec
West Main, 35%	100	0.7	6.9	3.5	4.2	2.6	3.2	1.8	2.0	1.9	3.4	3.1	26.5
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	20.4
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.4
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4
West Main, 29%	100	0.0	2.9	0.0	1.0	0.0	0.0	0.2	0.0	0.0	0.9	1.1	16.4
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.8
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Main, 24%	100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1
	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyoming, 35%	100	4.2	30.5	14.4	0.0	1.3	2.9	5.2	8.1	3.5	0.8	13.2	10.3
	200	0.1	26.6	10.0	0.0	0.0	0.3	3.7	6.1	0.3	0.0	8.0	6.0
	300	0.0	22.8	5.7	0.0	0.0	0.0	2.3	4.2	0.0	0.0	2.9	1.7
	400	0.0	18.9	1.3	0.0	0.0	0.0	0.9	2.3	0.0	0.0	0.0	0.0
	500	0.0	15.1	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0
Wyoming, 29%	100	0.3	24.0	9.3	0.0	0.0	0.0	3.1	5.0	0.0	0.0	8.3	5.6
	200	0.0	20.4	5.3	0.0	0.0	0.0	2.3	3.7	0.0	0.0	3.6	1.9
	300	0.0	16.7	1.4	0.0	0.0	0.0	1.5	2.4	0.0	0.0	0.0	0.0
	400	0.0	13.0	0.0	0.0	0.0	0.0	0.6	1.1	0.0	0.0	0.0	0.0
	500	0.0	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyoming, 24%	100	0.0	17.9	4.2	0.0	0.0	0.0	0.8	1.3	0.0	0.0	3.1	1.0
	200	0.0	14.1	0.5	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0
	300	0.0	10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	400	0.0	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	500	0.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Yakima, 29%	100	2.8	3.0	4.8	8.0	4.6	6.7	4.7	6.3	8.7	10.2	1.8	27.9
	200	0.0	0.0	0.9	4.2	1.7	6.0	4.4	2.7	5.0	4.1	0.0	21.2
	300	0.0	0.0	0.0	0.4	0.0	5.2	4.0	0.0	1.4	0.0	0.0	14.6
	400	0.0	0.0	0.0	0.0	0.0	4.4	3.6	0.0	0.0	0.0	0.0	7.9
	500	0.0	0.0	0.0	0.0	0.0	3.6	3.2	0.0	0.0	0.0	0.0	1.2
Yakima, 24%	100	2.3	2.2	3.1	6.0	3.1	4.5	3.0	4.5	5.5	7.4	0.6	22.9
	200	0.0	0.0	0.2	3.3	0.9	4.1	2.8	2.2	2.7	2.2	0.0	16.3
	300	0.0	0.0	0.0	0.6	0.0	3.8	2.7	0.0	0.0	0.0	0.0	9.8
	400	0.0	0.0	0.0	0.0	0.0	3.4	2.5	0.0	0.0	0.0	0.0	3.3
	500	0.0	0.0	0.0	0.0	0.0	3.0	2.3	0.0	0.0	0.0	0.0	0.0

Regional Resource by Capacity Factor	Resource Size (Nameplate MW)	Jan	Feb	Mar	Apr	May	Jun	July PLCC	Aug	Sep	Oct	Nov	Dec
Goshen, 29%	100	12.9	31.0	28.0	23.6	24.4	23.8	16.1	30.0	27.8	17.0	27.9	24.4
	200	8.4	25.4	20.6	18.7	19.7	18.0	13.5	25.2	23.1	12.7	21.5	18.4
	300	3.9	19.8	13.2	13.8	15.0	12.2	10.8	20.4	18.4	8.4	15.1	12.4
	400	0.0	14.2	5.8	9.0	10.3	6.5	8.2	15.7	13.8	4.2	8.7	6.4
	500	0.0	8.6	0.0	4.1	5.7	0.7	5.5	10.9	9.1	0.0	2.4	0.4
Goshen, 24%	100	10.6	25.3	23.9	18.7	20.0	20.1	12.4	24.8	22.2	13.1	23.0	20.7
	200	7.0	20.2	17.1	14.7	15.9	15.1	10.7	20.7	18.2	9.3	17.1	15.5
	300	3.4	15.0	10.2	10.6	11.9	10.1	9.0	16.6	14.3	5.5	11.2	10.4
	400	0.0	9.9	3.4	6.5	7.8	5.1	7.2	12.5	10.3	1.8	5.3	5.2
	500	0.0	4.8	0.0	2.4	3.8	0.2	5.5	8.4	6.4	0.0	0.0	0.1
Utah, 29%	100	13.6	11.1	33.1	40.8	51.0	42.4	37.6	38.2	36.2	28.4	22.0	21.2
	200	10.3	9.1	28.0	35.2	45.7	38.5	34.1	34.0	31.5	23.6	18.4	17.1
	300	7.0	7.0	22.8	29.5	40.3	34.6	30.7	29.9	26.9	18.8	14.8	13.1
	400	3.6	5.0	17.6	23.9	35.0	30.7	27.2	25.8	22.3	14.0	11.2	9.0
	500	0.3	2.9	12.5	18.3	29.7	26.8	23.8	21.7	17.6	9.2	7.6	5.0
Utah, 24%	100	11.7	7.8	24.8	35.5	41.7	32.8	27.3	30.0	27.0	24.6	16.9	17.4
	200	8.5	6.3	20.4	29.9	36.7	28.9	24.2	26.1	22.4	19.9	13.8	13.8
	300	5.3	4.8	16.0	24.2	31.6	25.1	21.0	22.2	17.9	15.3	10.7	10.2
	400	2.0	3.3	11.5	18.6	26.5	21.2	17.9	18.3	13.3	10.6	7.7	6.6
	500	0.0	1.8	7.1	13.0	21.4	17.4	14.7	14.4	8.8	6.0	4.6	3.1
Walla Walla, 35%	100	3.2	3.4	7.2	11.0	6.3	9.6	7.2	8.5	13.2	13.0	3.6	33.3
	200	0.0	0.0	1.9	5.6	2.3	8.1	6.3	3.3	8.2	5.5	0.0	26.3
	300	0.0	0.0	0.0	0.3	0.0	6.6	5.5	0.0	3.3	0.0	0.0	19.2
	400	0.0	0.0	0.0	0.0	0.0	5.1	4.6	0.0	0.0	0.0	0.0	12.2
	500	0.0	0.0	0.0	0.0	0.0	3.6	3.7	0.0	0.0	0.0	0.0	5.2
Walla Walla, 29%	100	2.7	2.4	5.6	8.8	4.6	7.0	5.2	6.7	9.8	10.0	2.7	27.1
	200	0.0	0.0	1.7	5.4	1.9	6.2	4.8	3.3	6.1	3.8	0.0	20.4
	300	0.0	0.0	0.0	1.9	0.0	5.4	4.3	0.0	2.4	0.0	0.0	13.8
	400	0.0	0.0	0.0	0.0	0.0	4.6	3.8	0.0	0.0	0.0	0.0	7.1
	500	0.0	0.0	0.0	0.0	0.0	3.9	3.4	0.0	0.0	0.0	0.0	0.4
Walla Walla, 24%	100	2.1	1.5	3.4	6.4	3.0	4.6	3.3	4.9	6.2	7.3	1.3	21.9
	200	0.0	0.0	0.5	4.1	1.1	4.2	3.1	2.6	3.4	2.0	0.0	15.4
	300	0.0	0.0	0.0	1.8	0.0	3.9	2.9	0.3	0.5	0.0	0.0	8.9
	400	0.0	0.0	0.0	0.0	0.0	3.5	2.7	0.0	0.0	0.0	0.0	2.5
	500	0.0	0.0	0.0	0.0	0.0	3.2	2.5	0.0	0.0	0.0	0.0	0.0

*The generation data used to determine the PLCC for the generic Utah wind resource was derived from a single bid from the 2003 Renewables RFP. When compared to generation from qualifying facilities within the general region, the estimates appear reasonable.

APPENDIX G – DSM DECREMENT ANALYSIS

CLASS 2 DSM DECREMENT ANALYSES

This section presents the results of the Class 2 demand-side management decrement analysis. For this analysis, the preferred portfolio was used to calculate the decrement value of various types of Class 2 programs following the methodology described in Chapter 7. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of potential new programs between IRP cycles. Note that for the next IRP, the company intends to model Class 2 DSM programs as options in the CEM.

Modeling Results

For the 2008 IRP, results are provided for both the $8 and $45 CO_2 tax levels to provide a perspective on CO_2 tax impacts on DSM Decrement values. For each tax level there are two tables and two charts providing an east and west nominal dollar per megawatt values. Tables G.1 and G.2 show the nominal results of the 12 11 decrement cases for each year of the 2017-year study period. Although no resources were deferred or eliminated from the portfolio due to the addition of Class 2 decrements, there is value in having to produce less generation to meet a smaller load. Consistent with the results for the 2007 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The commercial lighting, residential lighting, and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table G.1 – Annual Nominal Avoided Costs for Decrements, $8 CO2 Tax, 2010-2017

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)							
		2010	2011	2012	2013	2014	2015	2016	2017
EAST									
Residential Cooling	7%	52.83	58.07	61.88	73.26	69.99	75.43	82.86	93.08
Residential Lighting	60%	36.26	42.45	45.74	52.64	52.19	54.07	57.62	65.19
Residential Whole House	46%	36.61	42.33	45.54	52.09	52.12	53.99	57.92	65.67
Commercial Cooling	16%	44.08	49.76	53.28	59.67	58.96	61.71	67.75	76.04
Commercial Lighting	49%	37.02	43.44	46.09	52.92	52.77	54.55	58.36	65.96
System East System Load Shape	65%	35.01	40.62	43.85	50.50	50.66	52.16	55.99	63.10
WEST									
Residential Cooling	20%	45.46	54.20	57.77	65.81	65.06	73.29	81.77	87.30
Residential Heating	28%	40.65	50.96	53.06	55.86	56.89	61.13	66.48	71.37
Residential Lighting	60%	41.67	50.08	52.78	58.11	58.11	64.22	71.04	75.78
Commercial Cooling	16%	44.37	52.76	56.47	63.35	63.35	71.19	78.97	84.60
Residential Whole House	35%	40.86	49.54	52.44	57.27	57.90	63.27	69.45	73.94
Commercial Lighting	49%	40.94	49.62	52.39	57.38	58.28	63.77	69.64	74.96
System West System Load Shape	67%	40.46	48.34	50.81	56.11	56.41	62.06	68.65	73.05

Table G.2 – Annual Nominal Avoided Costs for Decrements, $8 CO2 Tax, 2018-2026

Decrement Name	Decrement Values (Nominal $/MWh)								
	2018	2019	2020	2021	2022	2023	2024	2025	2026
EAST									
Residential Cooling	102.24	112.31	121.93	112.80	112.66	124.13	124.39	135.27	145.24
Residential Lighting	70.62	78.45	79.26	78.82	80.00	85.72	89.19	95.44	98.77
Residential Whole House	71.16	79.20	80.09	78.90	80.18	86.15	88.88	95.27	98.67
Commercial Cooling	84.04	92.00	96.26	92.70	95.08	100.60	104.44	116.81	122.93
Commercial Lighting	70.47	78.29	78.36	78.19	79.21	84.77	87.05	94.65	98.23
System East System Load Shape	68.27	75.81	76.78	75.78	77.21	83.04	85.74	92.24	95.51
WEST									
Residential Cooling	93.85	94.81	95.96	91.33	93.32	98.57	105.22	102.35	104.04
Residential Heating	74.67	72.50	71.74	72.95	73.76	79.03	84.11	86.21	86.37
Residential Lighting	80.32	79.57	79.66	78.89	79.65	85.08	89.11	91.42	91.06
Commercial Cooling	89.91	90.65	92.57	88.36	91.16	95.41	101.51	102.57	101.83
Residential Whole House	78.50	77.34	77.06	76.33	78.12	83.98	86.93	87.72	87.72
Commercial Lighting	79.57	79.13	78.92	78.38	79.88	85.30	87.32	89.74	90.80
System West System Load Shape	77.82	76.59	77.55	75.90	77.41	82.75	85.88	88.18	88.50

Figures G.1 and G.2 show the decrement costs, at the $8 CO_2 tax level, for each end use along with the average annual forward market price for that location: Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.

Figure G.1 – East Decrement Price Trends

Figure G.2 – West Decrement Price Trends

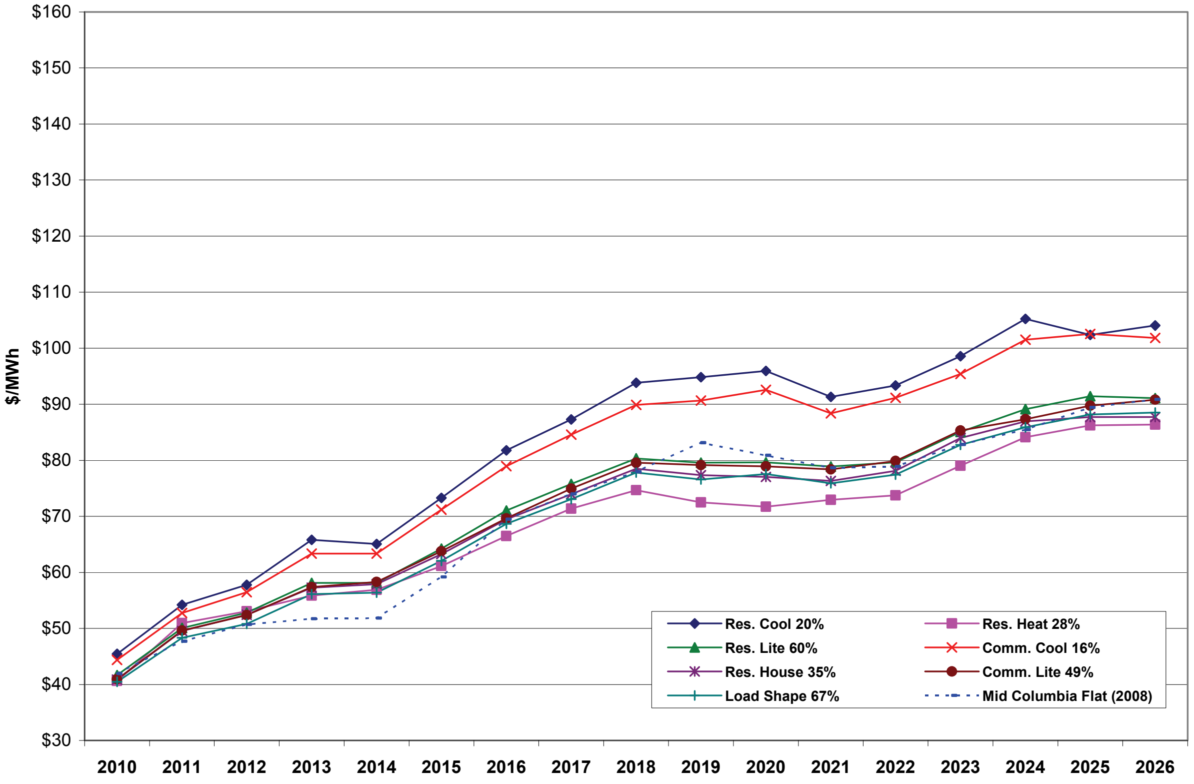


Table G.3 – Annual Nominal Avoided Costs for Decrements, $45 CO2 Tax, 2010-2017

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)							
		2010	2011	2012	2013	2014	2015	2016	2017
EAST									
Residential Cooling	7%	53.70	73.94	74.98	117.68	116.62	122.25	135.21	144.46
Residential Lighting	60%	31.96	52.07	56.66	94.01	95.14	99.41	104.35	111.92
Residential Whole House	46%	32.57	51.83	56.38	93.24	94.45	99.71	105.21	112.12
Commercial Cooling	16%	43.18	63.20	65.63	102.02	104.76	109.17	117.81	124.47
Commercial Lighting	49%	32.54	52.90	57.46	93.25	96.33	100.21	104.79	111.92
East System Load Shape	65%	30.75	49.99	54.65	91.53	92.74	96.96	101.58	109.26
WEST									
Residential Cooling	20%	59.03	72.98	74.52	109.12	112.50	120.10	130.56	137.63
Residential Heating	28%	48.29	61.90	64.46	92.60	96.72	103.87	109.12	117.53
Residential Lighting	60%	52.62	65.45	66.90	97.27	100.74	108.47	116.47	123.88
Commercial Cooling	16%	57.25	71.28	73.28	104.00	109.54	116.75	127.23	133.53
Residential Whole House	35%	50.99	63.52	65.63	95.82	99.57	107.75	113.38	120.46
Commercial Lighting	49%	49.80	63.75	65.81	94.58	99.59	107.17	114.58	122.07
West System Load Shape	67%	51.08	63.26	64.58	94.71	98.48	105.64	113.12	120.18

Table G.4 – Annual Nominal Avoided Costs for Decrements, $45 CO2 Tax, 2018-2026

Decrement Name	Decrement Values (Nominal $/MWh)								
	2018	2019	2020	2021	2022	2023	2024	2025	2026
EAST									
Residential Cooling	152.82	158.52	180.89	165.62	172.36	178.33	172.47	185.17	188.46
Residential Lighting	116.88	125.76	130.84	129.93	134.57	141.52	140.90	143.71	144.93
Residential Whole House	116.75	124.37	132.11	129.20	133.77	141.87	141.18	143.20	144.61
Commercial Cooling	132.18	141.85	150.46	146.17	152.92	158.08	158.57	166.04	170.87
Commercial Lighting	115.94	124.05	129.78	127.73	133.24	138.94	140.62	142.57	145.73
East System Load Shape	114.21	121.38	127.20	125.65	130.03	136.92	136.81	139.36	140.93
WEST									
Residential Cooling	142.50	145.06	152.31	146.21	150.59	156.77	159.62	152.27	148.50
Residential Heating	120.50	118.93	122.56	123.06	127.82	133.85	136.06	133.37	130.60
Residential Lighting	126.32	127.27	132.71	130.32	135.19	140.90	141.74	138.77	136.02
Commercial Cooling	138.41	139.31	146.46	140.89	148.89	152.79	158.48	149.99	147.43
Residential Whole House	124.10	122.40	129.88	126.73	132.48	138.68	139.15	134.55	132.83
Commercial Lighting	124.51	124.80	131.95	128.38	134.59	139.90	141.22	136.24	134.93
West System Load Shape	123.39	122.35	129.20	125.80	131.20	137.05	137.61	134.76	132.21

Figures G.1 3 and G.2 3 show the decrement costs, at the $45 CO2 tax level, for each end use along with the average annual forward market price for that location: Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.

Figure G.3 – East Decrement Price Trends for $45 CO2 Tax Level

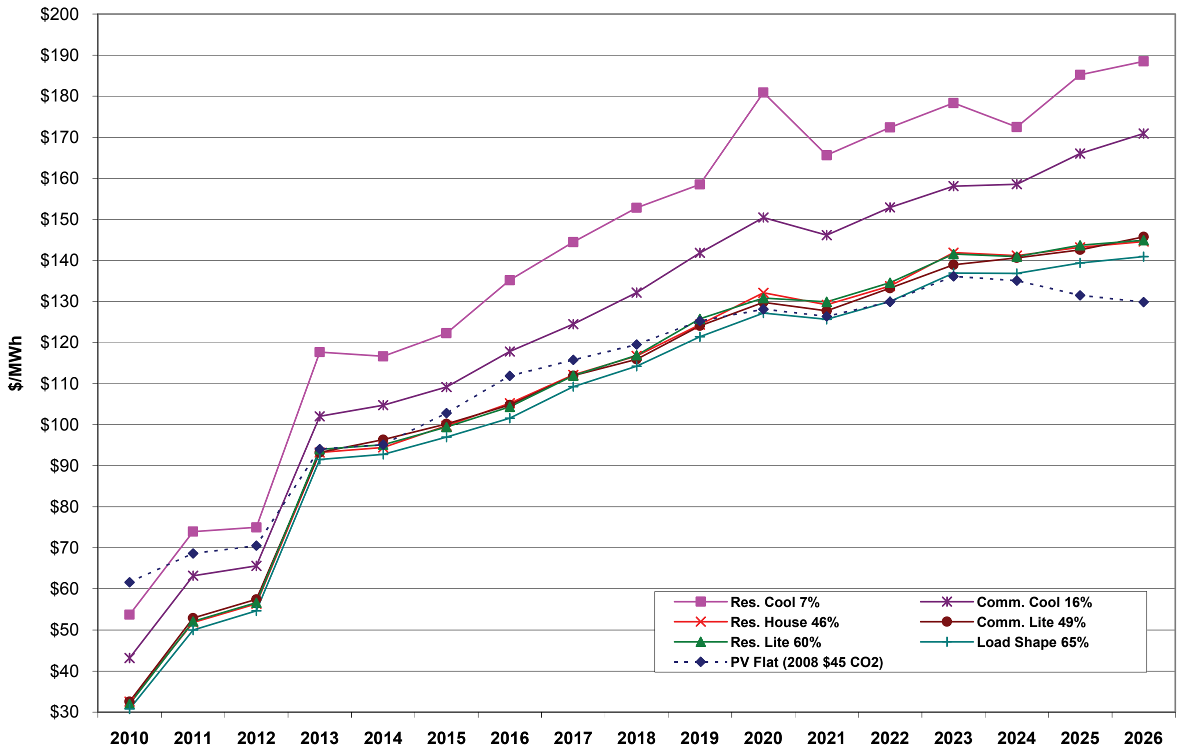
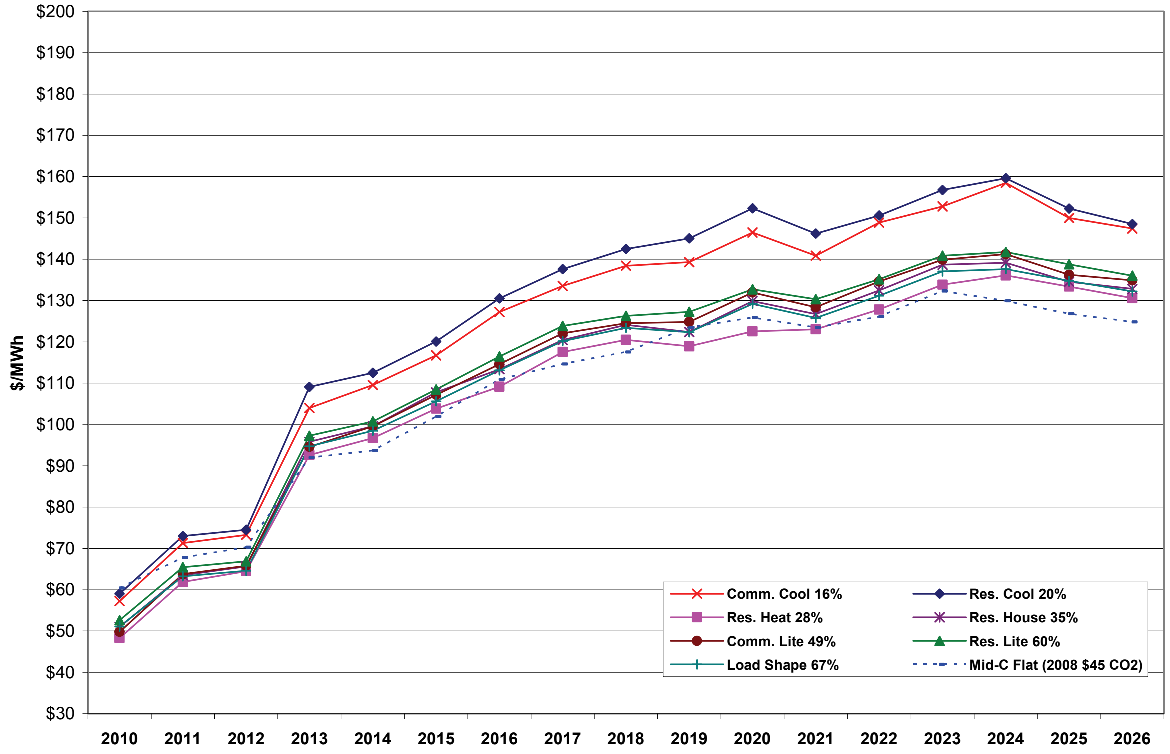


Figure G.4 – West Decrement Price Trends for $45 CO2 Tax Level



APPENDIX H – LOAD AND RESOURCE BALANCE WITH LAKE SIDE II INCLUDED AS A PLANNED RESOURCE IN 2012

The following tables and charts report load and resource balance information for capacity and energy assuming that the Lake Side II combined-cycle plant (with a 596 MW summer capability) is included as a planned resource in 2012. As noted in the IRP main volume, PacifiCorp's initial portfolio analysis assumed the inclusion of this resource.

Table H.1 – Capacity Loads and Resources including Lake Side II (12% Target Reserve Margin)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East										
Thermal	5,983	5,998	6,025	6,662	6,662	6,674	6,675	6,683	6,684	6,459
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
QF	151	151	151	151	151	151	151	151	151	151
Interruptible	237	237	237	237	237	237	237	237	237	237
Transfers	876	952	602	235	263	465	230	230	393	589
East Existing Resources	**8,636**	**8,572**	**8,284**	**8,384**	**8,422**	**8,645**	**8,418**	**8,415**	**8,589**	**8,571**
Load	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	**7,538**	**7,717**	**7,908**	**8,151**	**8,388**	**8,524**	**8,774**	**9,048**	**9,150**	**9,355**
Planning reserves	745	785	803	853	880	895	924	958	969	993
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	**815**	**855**	**874**	**923**	**951**	**966**	**995**	**1,029**	**1,040**	**1,063**
East Obligation + Reserves	**8,352**	**8,572**	**8,781**	**9,074**	**9,339**	**9,490**	**9,769**	**10,077**	**10,190**	**10,418**
East Position	**284**	**1**	**(498)**	**(690)**	**(917)**	**(845)**	**(1,350)**	**(1,662)**	**(1,601)**	**(1,848)**
East Reserve Margin	**16%**	**12%**	**6%**	**4%**	**1%**	**2%**	**(3%)**	**(6%)**	**(5%)**	**(8%)**
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydro	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
DSM	-	-	-	-	-	-	-	-	-	-
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
QF	120	120	120	120	120	120	120	120	120	120
Transfers	(878)	(953)	(603)	(235)	(264)	(465)	(229)	(229)	(392)	(588)
West Existing Resources	**4,507**	**4,242**	**4,150**	**3,649**	**3,691**	**3,492**	**3,840**	**3,833**	**3,654**	**3,483**
Load	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	**3,892**	**3,912**	**3,780**	**3,845**	**3,896**	**3,980**	**3,927**	**3,932**	**4,001**	**4,086**
Planning reserves	310	325	363	448	450	464	458	459	467	474
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	**316**	**332**	**370**	**454**	**457**	**471**	**464**	**465**	**473**	**480**
West Obligation + Reserves	**4,208**	**4,243**	**4,149**	**4,299**	**4,353**	**4,451**	**4,391**	**4,397**	**4,474**	**4,566**
West Position	**299**	**(1)**	**0**	**(650)**	**(662)**	**(958)**	**(551)**	**(564)**	**(820)**	**(1,082)**
West Reserve Margin	**20%**	**12%**	**12%**	**(5%)**	**(5%)**	**(12%)**	**(2%)**	**(2%)**	**(9%)**	**(14%)**
System										
Total Resources	**13,143**	**12,815**	**12,433**	**12,033**	**12,112**	**12,137**	**12,258**	**12,248**	**12,243**	**12,054**
Obligation	**11,430**	**11,628**	**11,687**	**11,996**	**12,284**	**12,504**	**12,701**	**12,980**	**13,151**	**13,441**
Reserves	**1,131**	**1,187**	**1,243**	**1,377**	**1,407**	**1,437**	**1,459**	**1,494**	**1,513**	**1,543**
Obligation + Reserves	**12,561**	**12,815**	**12,931**	**13,373**	**13,692**	**13,940**	**14,160**	**14,474**	**14,664**	**14,984**
System Position	**583**	**(0)**	**(498)**	**(1,340)**	**(1,579)**	**(1,803)**	**(1,902)**	**(2,226)**	**(2,421)**	**(2,930)**
Reserve Margin	**17%**	**12%**	**8%**	**1%**	**(1%)**	**(2%)**	**(3%)**	**(5%)**	**(6%)**	**(10%)**

Table H.2 – System Capacity Loads and Resources including Lake Side II (15% Target Reserve Margin)

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
System										
Total Resources	13,143	12,815	12,433	12,033	12,112	12,137	12,258	12,248	12,243	12,054
Obligation	11,430	11,628	11,687	11,996	12,284	12,504	12,701	12,980	13,151	13,441
Reserves	1,395	1,464	1,535	1,703	1,740	1,776	1,805	1,848	1,872	1,910
Obligation + Reserves (15%)	12,824	13,092	13,222	13,698	14,024	14,280	14,505	14,828	15,023	15,351
System Position	319	(277)	(789)	(1,665)	(1,912)	(2,143)	(2,247)	(2,580)	(2,780)	(3,297)
Reserve Margin	18%	13%	8%	1%	(1%)	(2%)	(3%)	(5%)	(6%)	(10%)

Figure H.1 – System Capacity Position Trend including Lake Side II

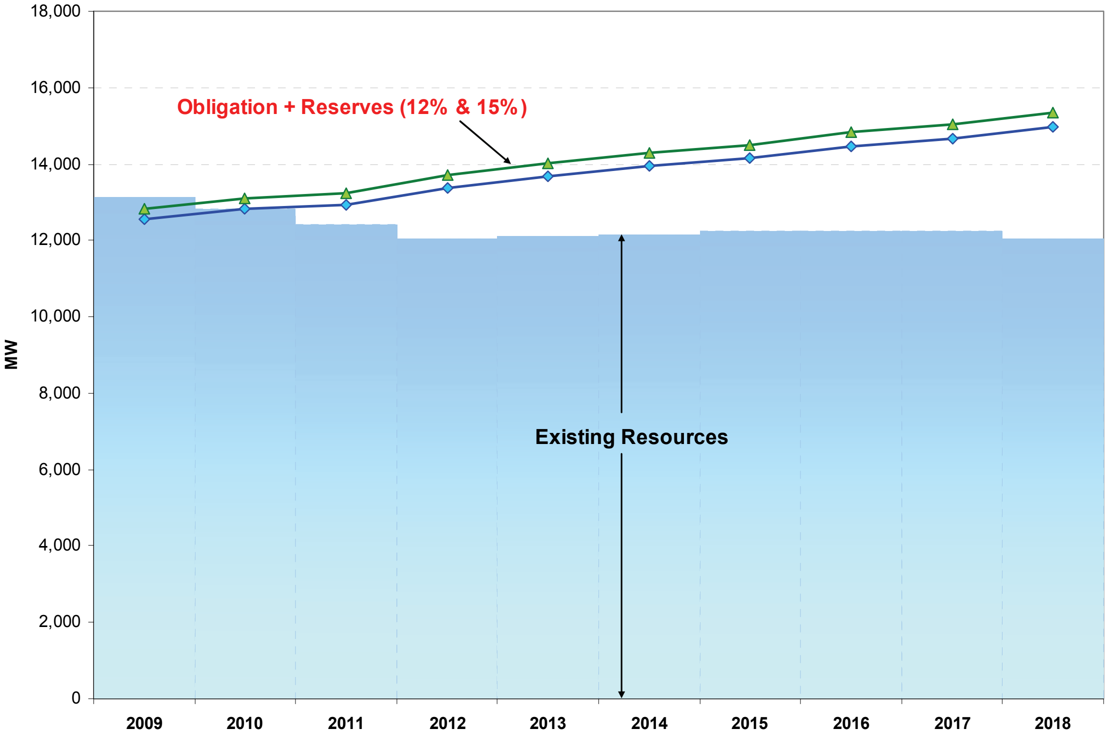


Figure H.2 – East Capacity Position Trend including Lake Side II

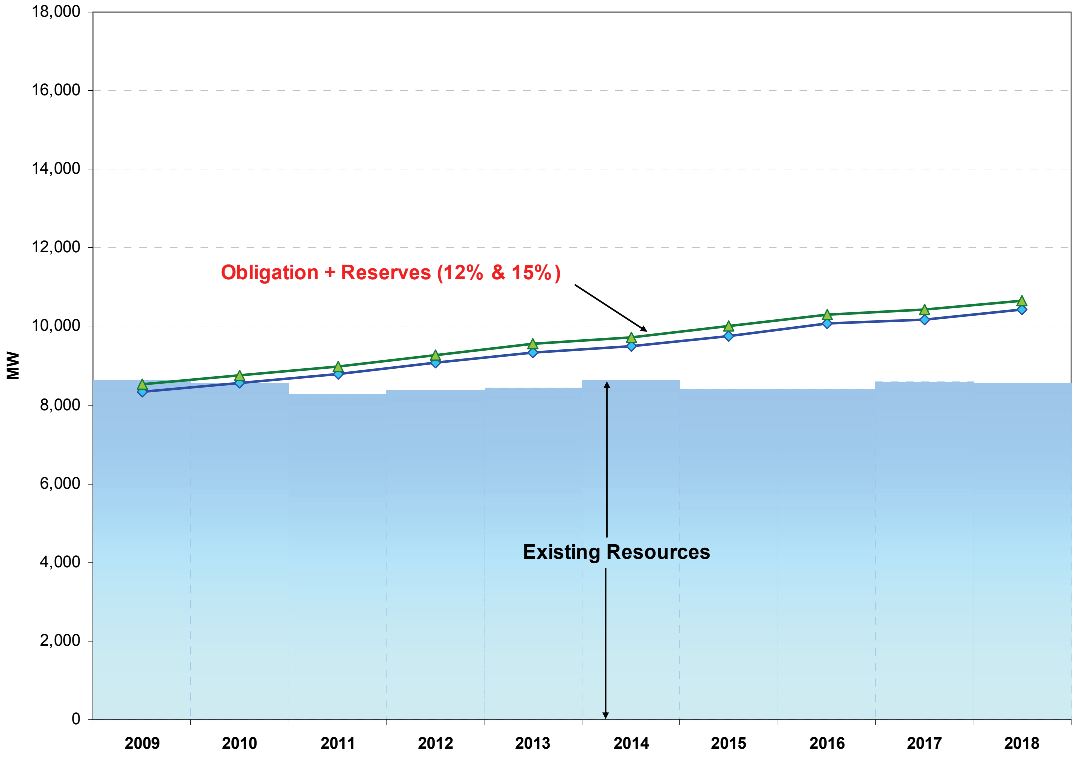


Figure H.3 – System Average Monthly and Annual Energy Balances including Lake Side II

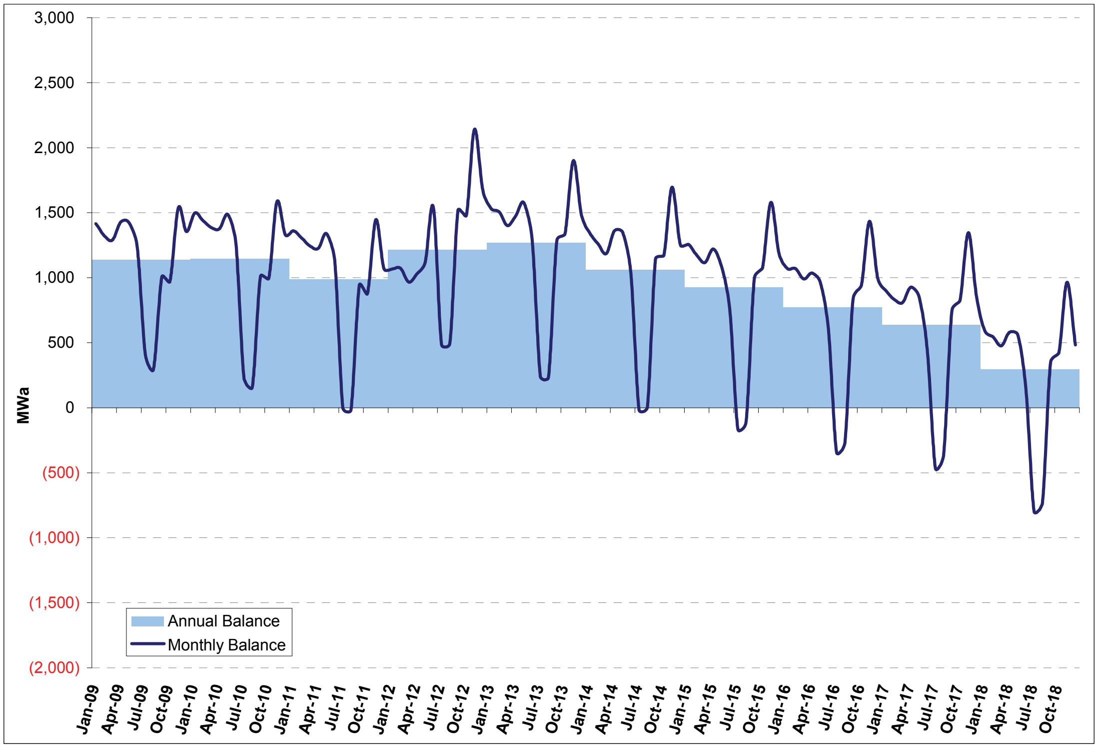


Figure H.4 – East Average Monthly and Annual Energy Balances including Lake Side II