Choosing a Resource Plan

Quantitative analysis delivers a great deal of information about how resource choices will perform over time and under different assumed conditions, but choosing a resource strategy also involves applying what the company has learned from listening to customers, operating in the marketplace, and observing regulatory developments. Here PSE explains the reasoning behind the specific resource additions in this IRP.

I. Overview

Here we explain the reasoning behind the specific resource additions in this IRP, but it is helpful to understand that the reasoning is more important than the plan itself. The real value of the IRP is in what we learn through the planning process. The specific 20-year plan serves to focus the investigation, rather than predict the future. When the time for actual resource acquisitions comes, the strategic and analytical insights gained from thinking through these problems will make a far more valuable contribution than a list of resources in the plan.

Planning horizons as long as this one – a 20-year outlook – can be considered to have two distinct parts: a near-term "action window," and the longer period that follows**.** The action window is characterized by decisions and commitments that must be made in the near future to ensure reliable service for PSE's customers. The later, longer term reveals the consequences of those choices and the impact they may have on decisions the company will have to make in the future.

The length of the action window differs depending on which resources are being discussed. For example, the action window for some energy efficiency measures may be fairly short (one to two years), because programs can be ramped up quickly. But the action window for wind generation that requires new transmission to be constructed may be as long as five to seven years. (It can take three to four years to site and build the generation facilities, and up to seven years to build the transmission.) In general, the following discussion considers the next three to five years to be the action window.

II. Electric Resource Plan

Figure 8-1 illustrates PSE's 2009 Electric Resource Plan. The plan integrates demand-side resources with renewable and nonrenewable supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting PSE customer needs reliably and responsibly over the next 20 years. Because wind power contributes only 5% of its capacity to meet peak, it is barely discernable on the chart in Figure 8-1. The table in Figure 8-2 lists the nameplate capacity additions by resource type.

Figure 8-1
2009 Electric Resource Plan
with Cumulative Peak Capacity Additions in MW

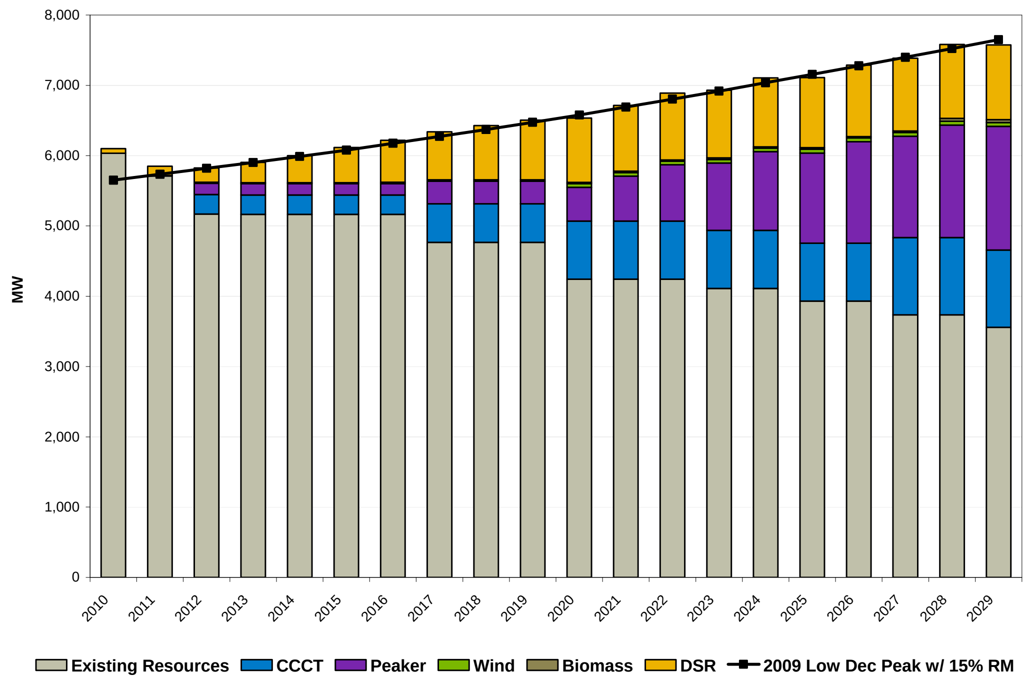


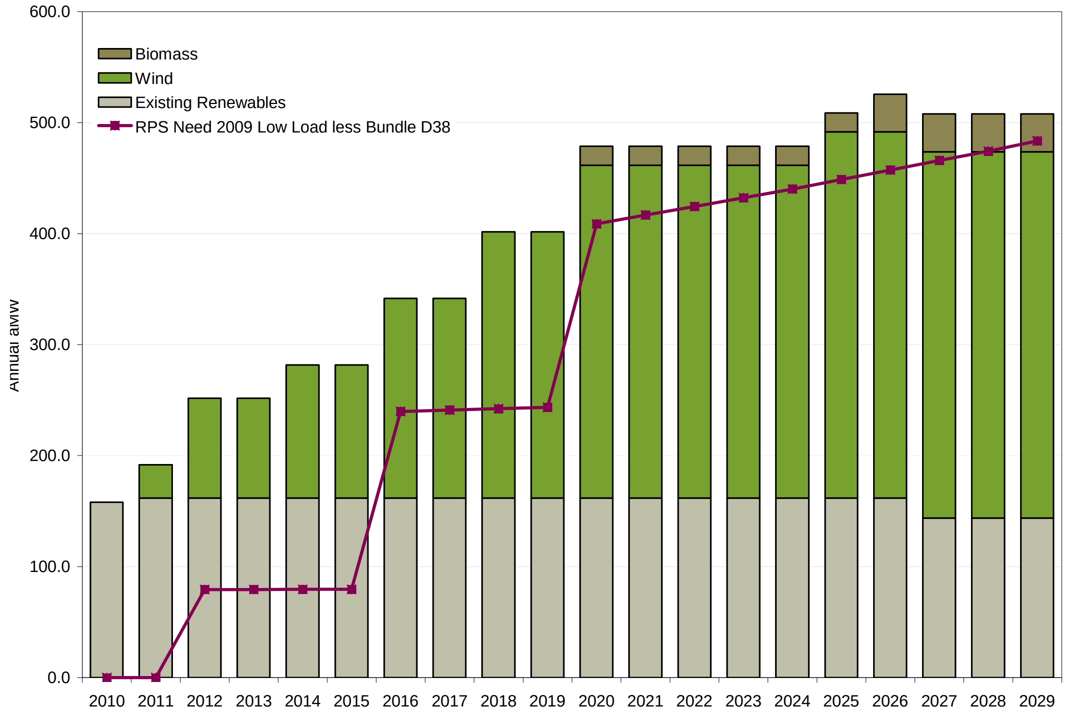
Figure 8-2
Cumulative Nameplate Capacity Additions by Resource Type in MW

	2012	2016	2020	2029
Demand-side Resources	205	597	917	1064
Wind	300	600	1000	1100
Biomass	0	0	20	40
CCCT w/Duct Firing	275	275	825	1100
Peakers	160	160	480	1760

Renewable resources reflected in this IRP are consistent with requirements of Washington's renewable portfolio standard (RPS) in RCW 19.285, Energy Independence Act. PSE also has set a voluntary, internal goal to achieve a higher level of renewable resources in the portfolio, 10% of load by 2013, to the extent these renewable resources are reasonably commercially available, necessary to meet load, and cost effective.[1] Results of analysis in this IRP demonstrate that it is cost effective to acquire wind resources to meet this goal, but Figure 8-3 illustrates the resource plan does not quite achieve that 10% goal—the IRP cost effectively reaches 9% by 2013 under current assumptions.

[1] Note: The cost effectiveness analysis reflects selling renewable energy credits into the wholesale market in excess of those needed to comply with RCW 19.285.

Figure 8-3
Renewable Resources in the Resource Plan
(Annual Average MWh)

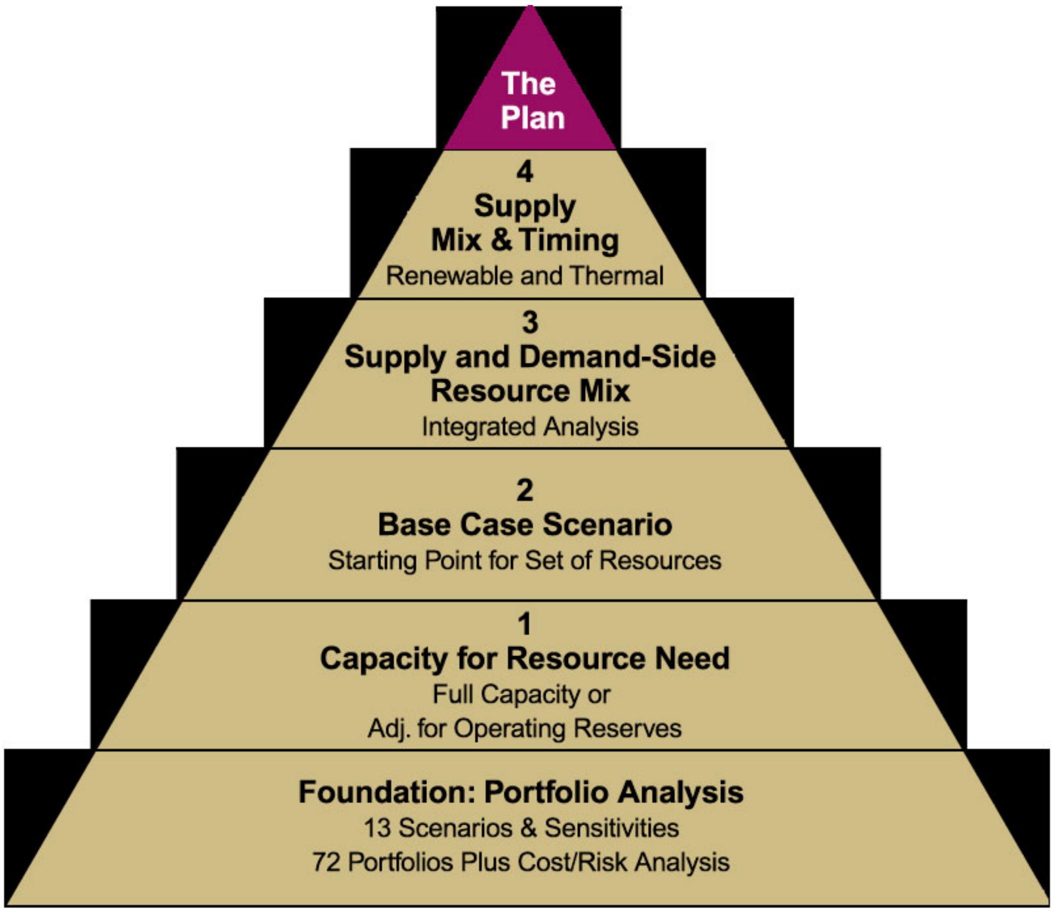


Summary of Electric Resource Plan Decisions

This plan is informed by the analysis performed on all the scenarios and sensitivities modeled for this IRP. However, it draws most heavily on the least cost resource plan analysis for the 2009 Trends scenario described in Chapter 5 to develop the specific set of resource builds.

Figure 8-4, below, illustrates how judgment was applied in developing the plan. The following text summarizes the decisions made at each step, while the issues involved in those decisions are discussed in more depth thereafter.

Figure 8-4
Development of the Resource Plan



Summary of Resource Plan Decisions

1. Assessment of capacity. Resources available to meet customer capacity needs were assessed in two ways for this IRP. One method used the full peak capacity value of existing resources to describe the “resource stack.” The other deducted operating reserves from resources. PSE chose to use the full peak capacity to calculate need, because we believed that deducting resources for operating reserves that are intended to address extremely short-term, unplanned outages of one hour or less may overstate long-term resource need. The abbreviation “Full-Cap” appears where this method was used.

2. Selection of a starting point. Worldwide, economic conditions changed radically during the development of this IRP analysis. In the spring of 2009, PSE developed new scenarios that allowed the company to incorporate post-downturn information about economic conditions into our assumptions. The 2009 Trends scenario was selected as the starting point and basis for the plan because it offered the most up-to-date assumptions. Among them were the following:

Load forecast: The 2009 Low Growth Update forecast reflects macroeconomic data available as of February 2009.

Natural gas prices: For 2010 through 2013, natural gas prices use three-month average forward prices for the period ending March 2, 2009; thereafter, Global Insight's long-run low forecast is applied.

Production tax credits (PTCs): PTC availability is based on the American Recovery and Reinvestment Act (Federal Stimulus Bill) passed in February 2009, which extends credits for wind through 2012 and biomass through 2013.

Resource costs: Low resource costs are expected to result from lower demand for energy.

CO_2 emission costs: CO_2 cost assumptions appear to approximately achieve 1990 emissions for the Western Electric Coordinating Council (WECC) by 2020, which is reasonable considering on-going activity on this front at the federal level.

3. Mix of demand-side and supply-side resources, and the pace of DSR additions. The demand-side resources target for this plan is 533 aMW at the generator over the next 20 years, with an accelerated ramp-in rate of 38 aMW (at the meter) for the first 11 years. This matches the total amount recommended by the optimization analysis, but slightly modifies the ramp-in rate because we have concerns about the practicality of achieving more than 38 aMW per year. We need to be able to count on that number, because the amount of DSR achieved has a significant impact on supply-side resources that must be developed or acquired.

4. Timing of renewable resource additions. This plan assumes that nearly all of the renewable energy for the electric portfolio will come from wind power, and that the timing of wind resource additions will proceed at a steady pace to achieve approximately 1,000 MW by 2020 to satisfy RPS requirements. The extension of production tax credits makes addition of wind resources in advance of RPS minimums part of a least cost portfolio through 2012. Thereafter, the plan continues additions at a measured pace while the optimization model proposes "just in time delivery" to meet RPS deadlines. We believe there are substantial benefits to be gained by PSE and its customers from a steady program, especially in a marketplace crowded by states that are urgently trying to assemble the resources to meet their own RPS requirements.

5. Timing of thermal resource additions. The primary factor influencing the mix and timing of peakers and combined cycle combustion turbine (CCCT) plants is the resource need assumption. Through 2016, this plan's recommendations match the least cost optimization analysis.

Discussion of Resource Plan Decisions

The least cost portfolio produced by the optimization model is a theoretical and ideal one based on specified inputs. The ways in which PSE modified the least cost "optimized" portfolio for the 2009 Trends Full-Cap scenario to better address real-world considerations is illustrated in Figure 8-5, and described in the following pages.

Figure 8-5
Resource Additions

<u>Optimal 2009 Trends Full-Cap Portfolio vs. 2009 Resource Plan</u>

2009 Trends Full-Cap Portfolio Cumulative Resource Additions

	DSR	Wind	Other Renewable (Geothermal & Biomass)	Peakers	CCCT
2012	192	200	20	160	275
2016	605	300	40	160	275
2020	808	800	65	640	825
2029	914	800	160	1,600	1,375

2009 Electric Resource Plan **Cumulative Resource Additions (MW)**

	DSR	Wind	Other Renewable (Biomass)	Peakers	CCCT
2012	205	300	0	160	275
2016	597	600	0	160	275
2020	917	1000	20	480	825
2029	1,064	1100	40	1,760	1,100

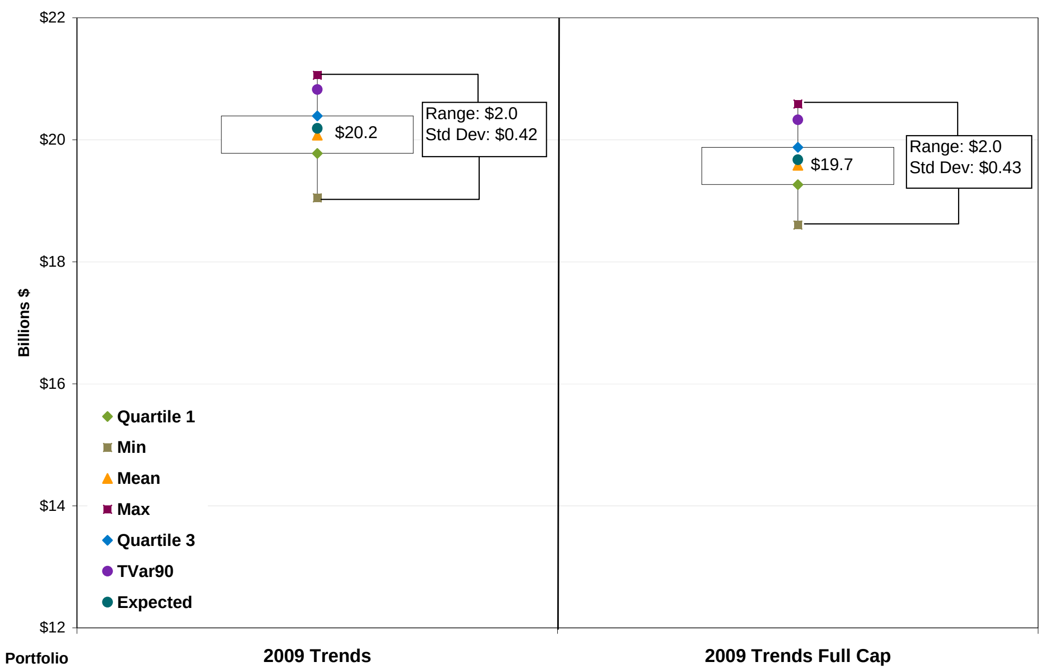
Capacity Assessment and Resource Need

Resource need is determined by subtracting the company's existing capacity to generate and supply power (its existing resources or "resource stack") from the capacity required to serve customer demand reliably. Therefore, different ways of assessing the capacity of existing resources can produce different calculations of resource need. This IRP considered two methods of assessing the capacity of existing resources. They differed in their treatment of operating reserves.

One method used the full peak capacity value of existing resources to describe the "resource stack." This method assumes that required operating reserves are included in the 15% planning reserve margin that the company maintains to achieve a 5% loss of load probability target. The other method deducts operating reserves from existing resources; in other words, it discounts the amount of available capacity by the amount of required operating reserves. For example, under existing North American Electric Reliability Council (NERC) Contingency Reserve obligations, a 275 MW CCCT operating at full capacity would require contingency reserves (which are a subset of total operating reserves) of19 MW (7%). The second method would assess the plant as only having an effective capacity of 256 MW of effective capacity available, while the first method would assess it at its full capacity of 275 MW.

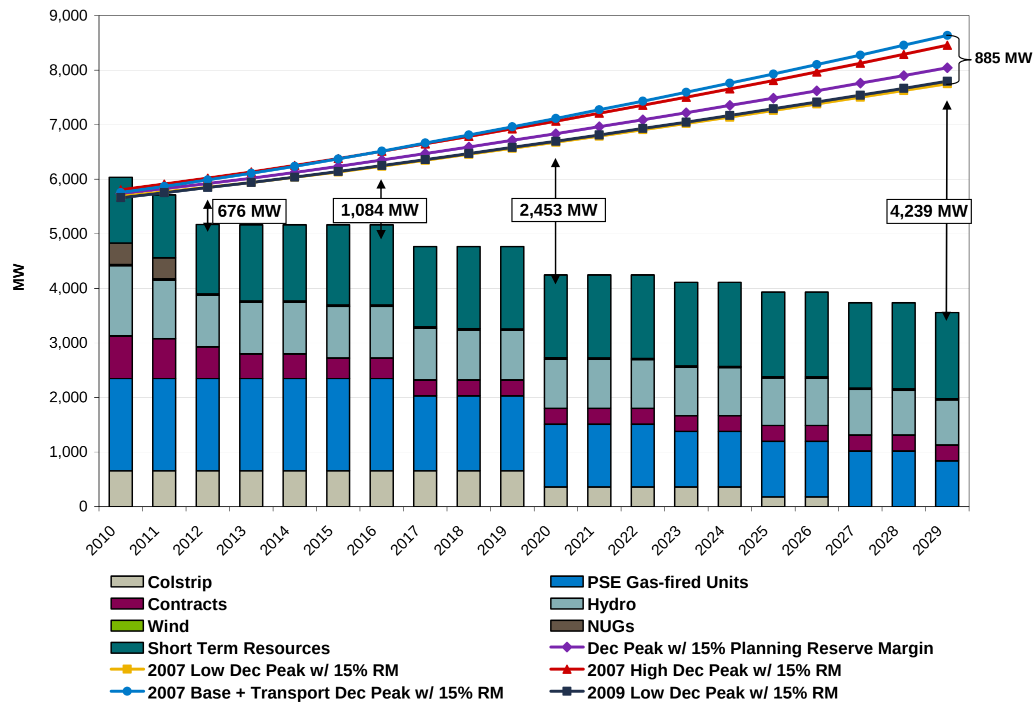
Ultimately, the different capacity assessments influence whether PSE needs to include one additional 275 MW gas CCCT plant in the resource plan by 2012. Figure 8-6 illustrates the box-plot depiction of costs and risks between the two approaches. This figure shows that the expected cost and range of costs are shifted down slightly without the additional power plant, but the shape of the risk profile is the same.

Figure 8-6
Long-term Impact of Alternate Capacity Assessments on Portfolio Cost and Risk



PSE elected to use the full peak capacity value of resources to calculate resource needs for this plan. This approach is reasonable and consistent with the way other utilities have addressed the question, and reasonable in that it avoids overstating PSE's long-term resource needs while we continue to refine this aspect of our analysis. As stated in the Action Plan discussed in Chapter 9, the company will be working with other utilities and stakeholders in the region to further refine this approach. Figure 8-7 illustrates resource need based on the 2009 Trends scenario using full peak capacity of resources.

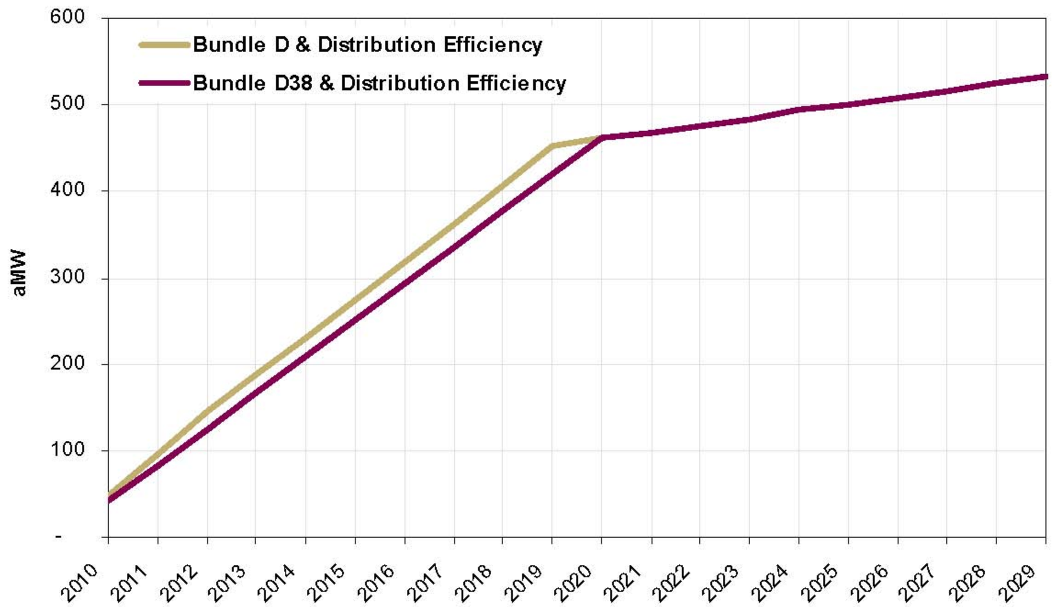
Figure 8-7
Electric Peak Capacity Resource Need
Full Peak Capacity Value of Resources & 2009 Low Load Forecast Update



Mix and Timing of Demand-side Resources

This resource plan adopts the same amount of demand-side resource (DSR) additions identified as least cost for the 2009 Trends scenario – 533 aMW (at the generator) over the next 20 years – but slightly modifies the timing of additions reflected in the optimization analysis. The optimization model proposed a ramp-in rate of 41 aMW (at the meter) per year for 10 years for those resources; instead, the resource plan adopts a ramp-in rate of 38 aMW per year for 11 years. (This adjustment was made to energy efficiency, demand response, and fuel conversion, but not distribution efficiency.) Figure 8-8 compares the cumulative annual energy savings reflected in the resource plan with the annual savings produced by the optimization model. This level of demand-side resources was labeled Bundle D in the analysis presented in Chapter 5. It is referred to as Bundle D38 in the resource plan, as we plan to attain bundle D at the pace of 38 aMW per year.

Figure 8-8
Bundle D38 Achieves Bundle D Savings in 11 Years



The accelerated ramp-in rate was adjusted for the resource plan because of concerns about the practicality of achieving 38 aMW of demand-side resources in today's marketplace. Thirty-eight aMW per year represents a significant expansion of PSE's existing programs. Because the people and resources capable of implementing such programs are highly sought-after, it will be challenging to achieve these savings. While the company believes that we *can* achieve them cost-effectively, we are *not* confident that we can achieve *greater* energy savings cost-effectively on an annual basis, especially in the next few years. Bundle D38 is also consistent with the lowest level of cost-effective DSR across all the scenarios. The analysis illustrated that at least 38 aMW per year of DSR was cost effective in every scenario examined. There is little risk that this amount would provide too much DSR to be cost effective. Therefore, Bundle D38 is practical and reasonable.

The level of achieved DSR affects the amount of supply-side resources for which PSE must plan and also the level of renewable resources the company is required to build. This means that PSE must be able to count on the amount of supply-side resources our program planners can reliably deliver in order to plan appropriately for supply-side resources. PSE may attempt to achieve higher rates of demand-side resource acquisitions, but we must be confident about the amount we *can* achieve because DSR has such a significant impact on other resources that must be acquired.

Mix of Renewable Resources

Renewable resource decisions include the amount of renewable resources to build, the mix of renewable resources, and the timing of additions. Figure 8-9 compares the optimization model's least cost mix of renewable resources across all scenarios and sensitivities presented in Chapter 5 (including the high and low RPS) with the resource plan. The following discussion explains why PSE selected the specific renewable resource additions in the resource plan.

Figure 8-9
Comparison of Cumulative Renewable Resource Builds in MW of Capacity
(Range of Least Cost Plans Across Scenarios vs. Resource Plan)

	Range of Cumulative Additions Across All Scenarios			2009 Resource Plan		
	Wind	**Other Renewable**	**Total Renewable**	**Wind**	**Biomass**	**Total Renew**
2012	0 – 300	0	0 – 300	300	0	300
2016	300 – 400	0 – 90	0 – 450	600	0	600
2020	0 – 800	65 – 160	65 – 950	1000	20	1020
2029	0 – 1200	160 – 310	160 – 1510	1100	40	1140

For the electric portfolio in this plan, nearly all renewable energy will come from wind power, with a small amount of biomass. This is the case even though the optimization model indicated that the least cost resource plan across different scenarios included varying amounts of biomass, concentrating solar thermal and geothermal resources. PSE chose this course because the company's experience in the marketplace leads us to question when non-wind renewable resources will be truly commercially available and capable of delivering utility-scale power As with DSR, the company must be able to count on the resources for which we will plan and build infrastructure.

Despite PSE's reputation among utilities for aggressive pursuit of renewable resources, our efforts to attract geothermal and biomass resources through the 2003, 2005, and 2007 RFP processes (and outside those processes) have not resulted in actual acquisitions. The company will continue to seek opportunities to acquire or develop commercial-scale, cost-effective non-wind renewable resources (including biomass, geothermal, and concentrating solar thermal), but we cannot rely upon them at this time to deliver the energy or capacity needed.

Mix and Timing of Resource Additions

Once it was determined that the geothermal and concentrating solar thermal resources were not practical alternatives, an additional sensitivity was developed to inform the overall schedule of resource additions. The “2009 Trends Constrained” sensitivity incorporated the judgments made so far.

- It assumed the full peak capacity value of resources.
- It adopted DSR Bundle D38.
- It excluded geothermal and concentrating solar as alternatives.

The optimization model then showed how these constraints would affect the least cost combination of renewable and thermal resources. Results for wind and biomass additions are presented in Figure 8-11; results for thermal builds are presented in Figure 8-12.

Timing of Renewable Resource Additions. The timing of wind resource additions in the plan proceeds at a steady pace to achieve approximately 1,000 MW by 2020 to satisfy RPS requirements. First PSE summarizes the important impact of the PTC extension on the timing of renewable additions during the near-term action window, and then we describe the basis for the overall schedule of wind additions.

The extension of the PTC provided for in the American Recovery and Reinvestment Act supports acceleration of wind additions sooner than needed to comply with RPS requirements. Figure 8-10, below, shows that wind resource additions from 100 to 300 MW by 2012 would be cost effective with the current RPS and extension of the PTC through 2012 or 2013. The figure also illustrates that without the PTC extension, additional wind by 2012 would not be cost effective, based on the assumptions in this IRP. Recall the 2009 Trends scenario includes a PTC extension for wind through 2012 and current RPS requirements.

Figure 8-10
Impact of PTC Extension on Acceleration of Wind Additions

	Range of Wind Additions (MW)	
	Additions in Scenarios With PTC Extension	**Additions inScenarios Without PTC Extension**
2012	100 – 300 MW	0

Figure 8-11 illustrates that wind power additions in the resource plan are consistent with the least cost 2009 Trends Constrained portfolio through 2012, reflecting the accelerated development of wind power above. Between 2014 and 2020, the schedules diverge; both arrive at 1,000 MW of wind power by 2020.

Figure 8-11
Comparison of Annual Renewable Resource Builds (in MW)
(2009 Trends Constrained Sensitivity vs. Resource Plan)

	2009 Trends Constrained (DSR Bundle D38, No Geothermal or Concentrating Solar Thermal)		2009 Resource Plan	
	Wind	**Biomass**	**Wind**	**Biomass**
2010	-	-	-	-
2011	100	-	100	-
2012	200	-	200	-
2013	-	-	-	-
2014	-	-	100	-
2015	-	-	-	-
2016	100	-	200	-
2017	-	-	-	-
2018	-	-	200	-
2019	-	-	-	-
2020	600	20	200	20
Total	*1000*	*20*	*1000*	*20*

The timing of wind power additions in the plan from 2014 through 2020 is based on the benefits that accrue from a steady, disciplined acquisition and development program, consistent with prior resource plans. Such an approach allows PSE to retain a team of experienced wind acquisition and development professionals capable of taking advantage of opportunities as they occur in the marketplace. The “just-in-time” development of 600 MW of wind in 2020 proposed in the 2009 Trends Constrained portfolio exposes the company and its customers to the risks and uncertainties of a boom-bust cycle that would create periodic scrambles to assemble qualified personnel and development opportunities, just so that requirements could be met at the last minute.

Mix and Timing of Nonrenewable Resource Additions. The backbone of PSE's supply portfolio for the next 20 years is composed of gas-fired combined-cycle combustion turbines for baseload needs, and gas-fired peakers with fuel-oil backup for peaking needs. The timing and mix of thermal resources in the resource plan is consistent with the least cost 2009 Trends Constrained portfolio described above. (Again, that sensitivity was developed to reflect the full capacity of existing resources, and examine how DSR Bundle D38 and the exclusion of geothermal and concentrating solar would affect the least cost combination of renewable and thermal resources.) Figure 8-12 compares a summary of thermal resource additions in the resource plan with those from the least cost 2009 Trends Constrained portfolio.

Figure 8-12
Cumulative Thermal Additions in MW

Least Cost 2009 Constrained Portfolio vs. 2009 Resource Plan

	Least Cost 2009 Trends Constrained		2009 Resource Plan	
	Peakers	CCCT w/ Duct Firing	Peakers	CCCT w/ Duct Firing
2012	160	275	160	275
2017	320	550	320	550
2020	480	825	480	825
2029	1,760	1,100	1,760	1,100

Additional Considerations

Implications of Near-term Decisions on Future Options

An important part of resource planning is consideration of how decisions made in the near term may limit opportunities in the longer term. This plan's near-term decisions do not appear to foreclose on future options. Figure 8-13 illustrates that resource additions through 2012 are part of the long-term least cost path across a broad range of futures considered in this IRP. All scenarios examined include at least 275 MW of CCCT w/Duct Firing by 2020, for example. The one exception is wind power in the low RPS sensitivity, which tested implications of RCW 19.285 being changed to require that just 3% of load be met by renewables for the entire study period. In that case, no additional wind power appeared cost effective. However, since RCW 19.285 recently passed through a legislative session unchanged, it seems unlikely that it would be so dramatically revised by 2012.

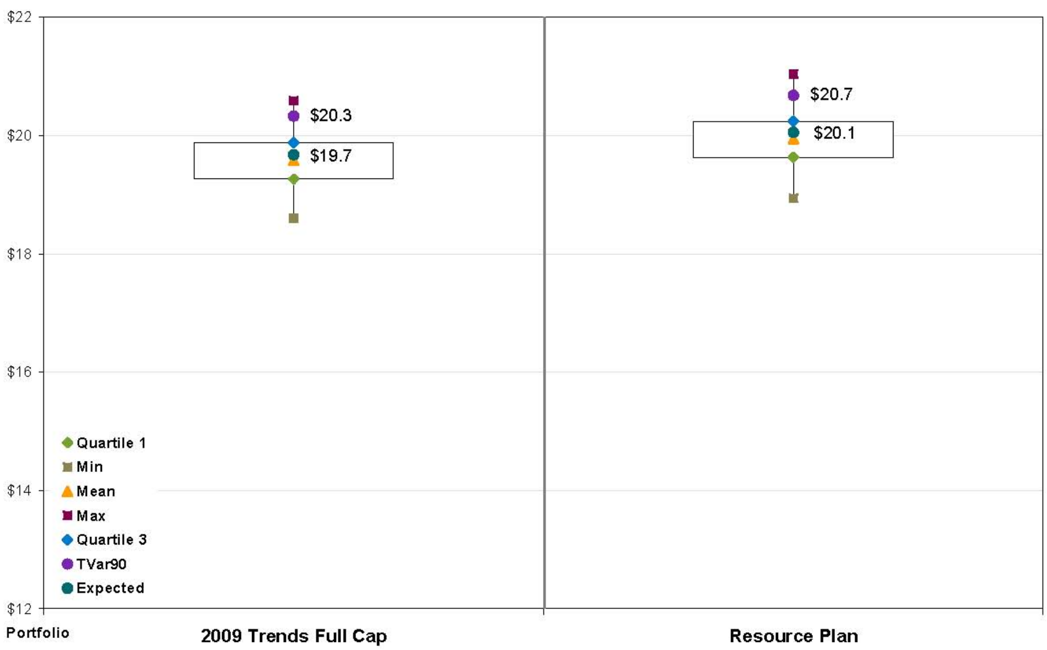
Figure 8-13
Resources in Action Window Are Part of All Future Least Cost Plans
(Cumulative Resource Additions in MW)

		DSR	Wind	Other Renewable	Peaker	CCCT w/ Duct Firing
2012	Resource Plan	205	300	-	160	275
2020	2009 Trends-Full-Cap	808	800	65	640	825
	Green World-Full-Cap	921	600	140	160	1,100
	2007 Trends-Full-Cap	994	700	140	320	1,100
	2007 BAU-Full-Cap	864	700	140	640	825
	High Growth-Full-Cap	994	800	85	160	1375
	2009 Trends	808	800	75	800	825
	2009 BAU	808	800	65	800	825
	High RPS	994	800	150	480	1,100
	Low RPS	994	-	65	480	1,100
	Transport Load	994	700	140	480	1,375

Costs and Emissions

Cost and Cost Risks. The analysis described in Chapter 5 led to a key finding: Future scenario conditions (specifically natural gas prices and carbon costs) have a significantly greater impact on costs than the specific set of resources contained in the portfolio. However, since the resource plan was not simply selected from among those produced by the optimization model but instead developed as described, it is important to report on the plan's costs and cost risks here. Figure 8-14 uses box-plot diagrams to illustrate the costs and cost-risk profiles of the resource plan and the optimal 2009 Trends Full-Cap portfolio that was used as a starting point. This demonstrates that the decisions to use Bundle D38, to avoid relying on geothermal and concentrating solar, and to change the timing of wind power additions from 2014 to 2020, have little impact on the cost and risk profile of the resource plan relative to the least cost 2009 Trends Full-Cap portfolio.

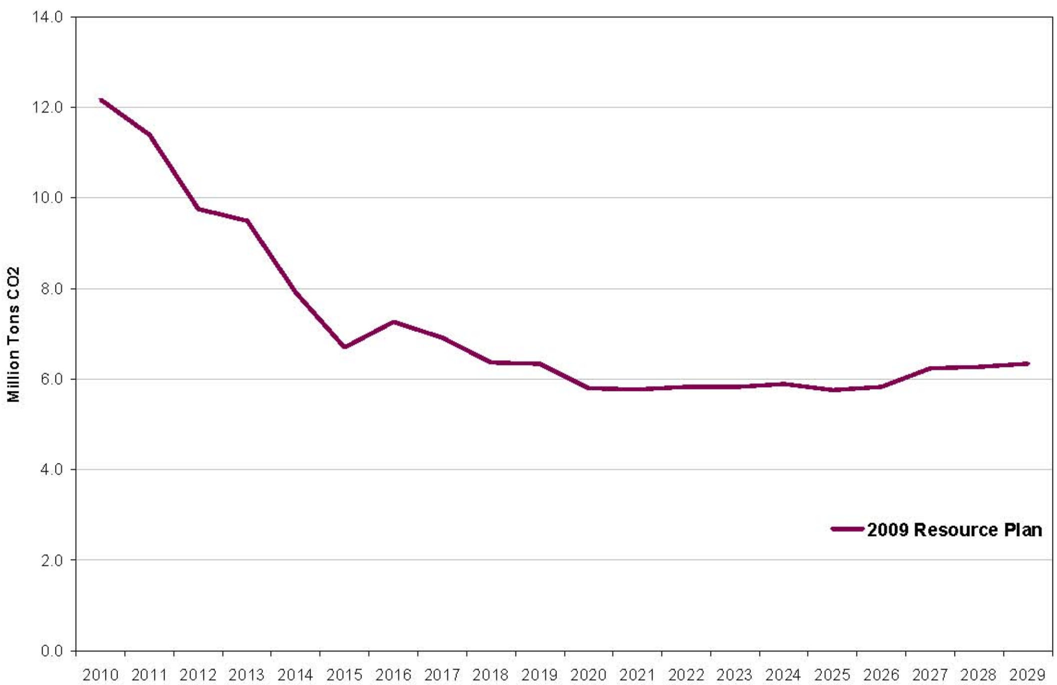
Figure 8-14
Cost/Risk Profiles Compared
Least Cost 2009 Trends Full-Cap vs. Resource Plan



(20-year NPV in $Billions)

Carbon Dioxide Emissions. Chapter 5 demonstrated that the primary factor affecting carbon emissions was cost of carbon from potential new regulations. Figure 8-15 illustrates CO_2 emissions from the resource plan within the 2009 Trends scenario (carbon costs start at $37 per ton in 2012 and increase to $130 per ton by 2029). The significant decline in CO_2 emissions by 2015 is caused by falling capacity factors at Colstrip, which is driven by increasing carbon costs. By 2020, Colstrip units 1 and 2 are retired. After 2020, Colstrip units 3 and 4 are still available, but they would be utilized for reliability purposes to provide capacity for colder than normal cold spells, rather than dispatched on a routine basis.

Figure 8-15
CO_2 from Resource Plan Decline Significantly



III. Gas Resource Plans

PSE developed two gas resource plans for this IRP; one for gas sales, and one for the company's combined gas needs, which reflected needs of gas-fired generation for the electric resource plan identified above. Electric generation will require increasing amounts of natural gas in the future, so looking at total gas resource need presents a more comprehensive picture of the challenges that will face the company and its customers in the years ahead.

The combined need perspective highlights the fact that a large majority of current PSE gas supplies come from a single supply basin, and that diversifying the source of supplies may be in the best interest of customers over the long term. However, a diversity strategy is not included in the final plans presented below, because analysis indicated that it would increase portfolio costs. PSE will continue to evaluate the costs and benefits of increasing pipeline capacity to diversify supply sources. A full discussion of this issue is included in Chapter 6, Gas Resources.

The gas resource plans integrate demand-side resources with supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting PSE needs reliably and responsibly over the next 20 years. They are based on the 2009 Trends scenario. This scenario includes load forecasts and gas price forecasts that were updated in February and March 2009.

Gas Sales Resource Plan

Figures 8-16 and 8-17 illustrate PSE's 2009 Gas Sales Resource Plan. The following discussion explains the reasoning that supports the specific elements of the plan, with an emphasis on resources needed early in the planning horizon.

Figure 8-16
2009 Gas Sales Resource Plan

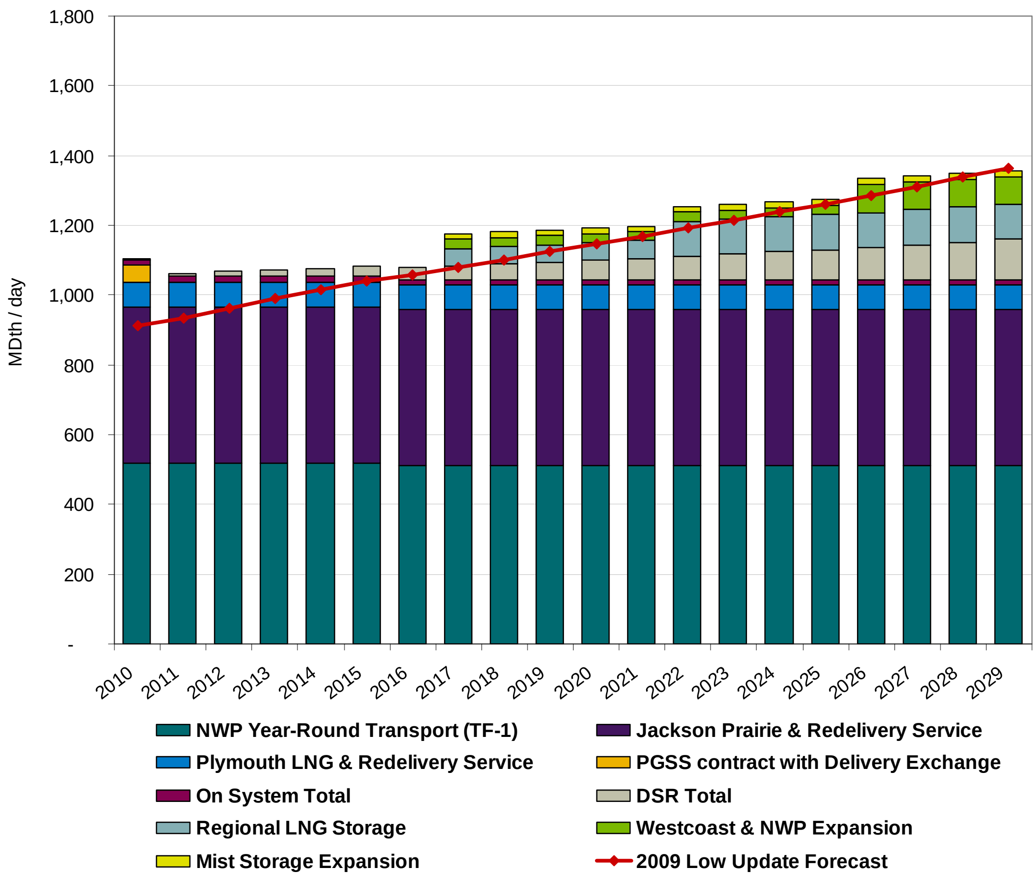


Figure 8-17
2009 Gas Sales Resource Plan Additions

	Additions in MDth/day			
	Regional LNG Storage	**Westcoast/NWP**	**Mist Storage & Pipeline**	**DSR**
2012				14
2017	50	30	16	26
2022	50			26
2026		62		20
2029				14
Total Additions	**100**	**92**	**16**	**100**

Combined Gas Resource Plan

The 2009 Combined Gas Resource Plan, summarized in Figures 8-18 and 8-19, addresses PSE's total natural gas need – gas required to fuel electric generation plus gas for retail sales customers.

Figure 8-18
2009 Combined Gas Resource Plan

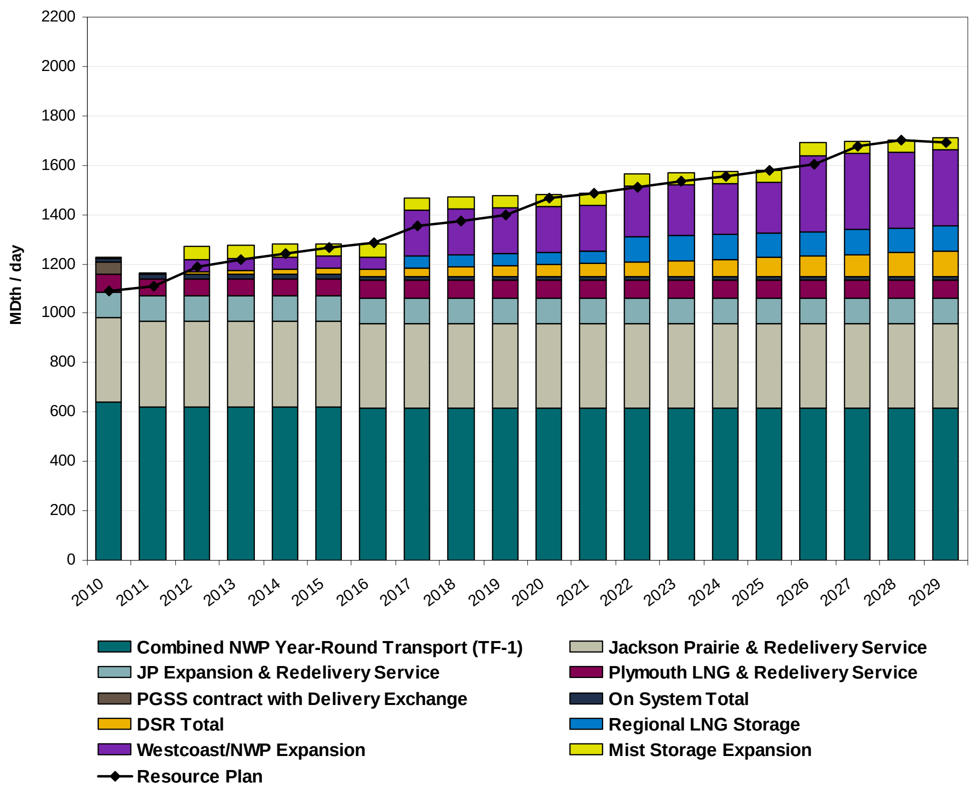


Figure 8-19
2009 Combined Gas Resource Plan

	Additions in MDth/day			
	Regional LNG Storage	**Westcoast/NWP**	**Mist Storage & Pipeline**	**DSR**
2012		50	50	14
2017	50	129		26
2022	50	20		26
2026		111		20
2029		0		14
Total Additions	100	310	50	100

Figure 8-20, below, compares the resource additions included in the Gas Sales Resource Plan with those in the Combined Gas Resource Plan. Reflecting the growing reliance on natural gas to fuel electric generation, the combined plan expands capacity to Northern British Columbia sooner than the gas sales plan. It also adds capacity in larger amounts than the gas sales plan throughout the 20-year study period. Finally, it includes more Mist storage and related transportation than the gas sales plan. Regional LNG storage, a needle-peaking resource, is the same in both.

Figure 8-20
Comparison of Resource Additions
Gas Sales Resource Plan vs. Combined Gas Resource Plan

	Additions in MDth/day							
	Regional LNG Storage		**Westcoast/NWP**		**Mist & Pipeline**		**DSR**	
	Sales	**Combined**	**Sales**	**Combined**	**Sales**	**Combined**	**Sales**	**Combined**
2012				50		50	14	14
2017	50	50	30	129	16		26	26
2022	50	50		20			26	26
2026			62	111			20	20
2029				0			14	14
Total Additions	**100**	**100**	**92**	**310**	**16**	**50**	**100**	**100**

Discussion of Gas Sales Resource Plan Decisions

The optimal portfolios produced by the SENDOUT analysis tool are theoretical portfolios based on specified inputs and need to be reviewed based on judgment and market conditions. In this case PSE made minor changes only to the SENDOUT demand-side resource acquisition schedule. In the years beyond 2020, the company reduced DSR to incorporate marketplace constraints in gas DSR acquisition, and increased Westcoast/Northwest pipeline capacity by corresponding amounts. Figure 8-21 compares the 2009 Trends SENDOUT results with the resource plan capacity additions.

Figure 8-21
Gas Sales Portfolio Resource Additions
2009 Trends vs. Resource Plan

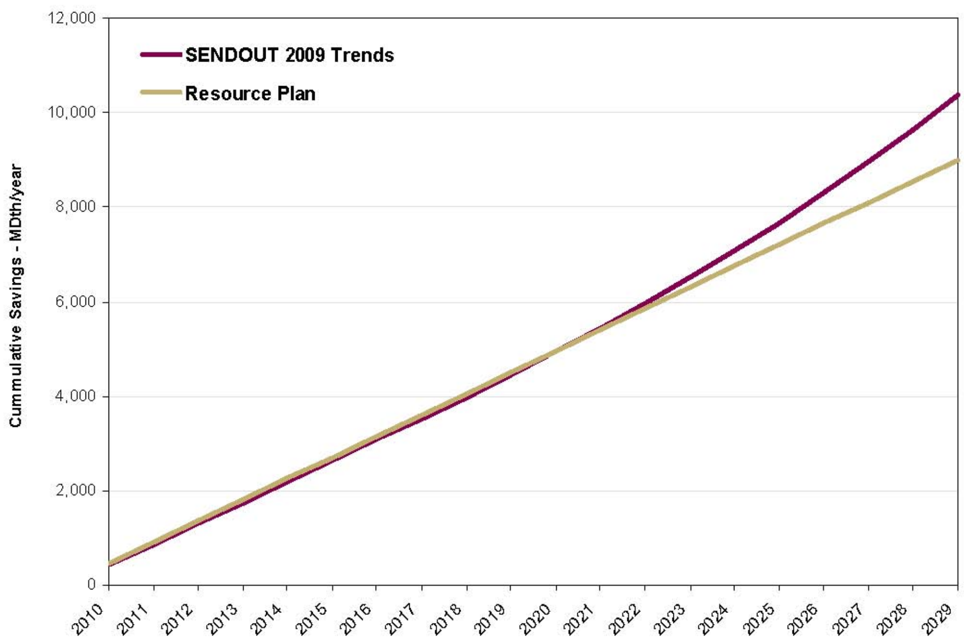
2009 Trends	Additions in MDth/day			
	Regional LNG Storage	Westcoast/NWP	Mist Storage & Pipeline	DSR
2012				14
2017	50	30	16	26
2022	50			27
2026		47		26
2029				22
Total Additions	**100**	**77**	**16**	**115**

Resource Plan	Additions in MDth/day			
	Regional LNG Storage	Westcoast/NWP	Mist Storage & Pipeline	DSR
2012				14
2017	50	30	16	26
2022	50			26
2026		62		20
2029				14
Total Additions	**100**	**92**	**16**	**100**

Demand-side Resource Additions

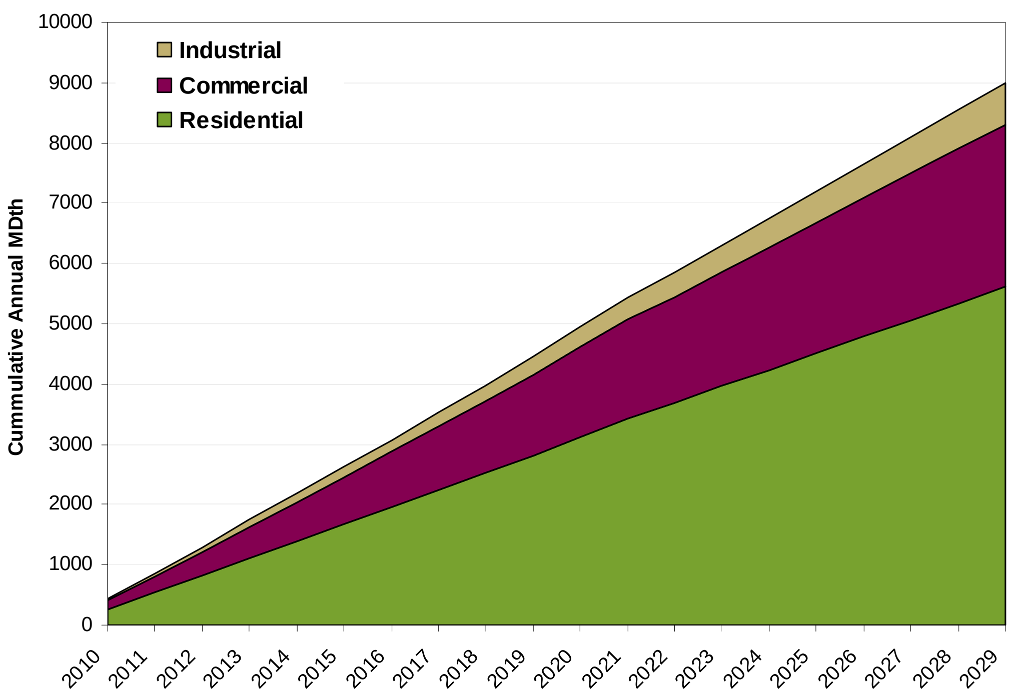
The 2009 Gas Sales Resource Plan includes about 3,600 MDth of demand-side resource savings by 2017 at an annual rate of 450 MDth per year, which translates to peak capacity savings of approximately 40 MDth per day. This is consistent with the level reflected in the SENDOUT optimization analysis for the 2009 Trends scenario up to the year 2020; after that the plan has a slightly lower acquisition rate. The 450 MDth annual rate represents a significant increase over PSE's current acquisition rate of approximately 350 MDth per year. We are not confident that PSE could achieve more on an annual basis, especially in the next few years, given current marketplace constraints. In the plan, DSR peak capacity additions were reduced consistent with the achievable annual volumes noted above, and Westcoast/Northwest Pipeline capacity was increased by corresponding amounts. Figure 8-22 below shows the difference in annual savings between the results modeled in SENDOUT and the resource plan.

Figure 8-22
Cumulative Energy Savings: SENDOUT vs. Gas Sales Resource Plan



The demand-side resources in the plan include contributions from every customer segment, as Figure 8-23 illustrates.

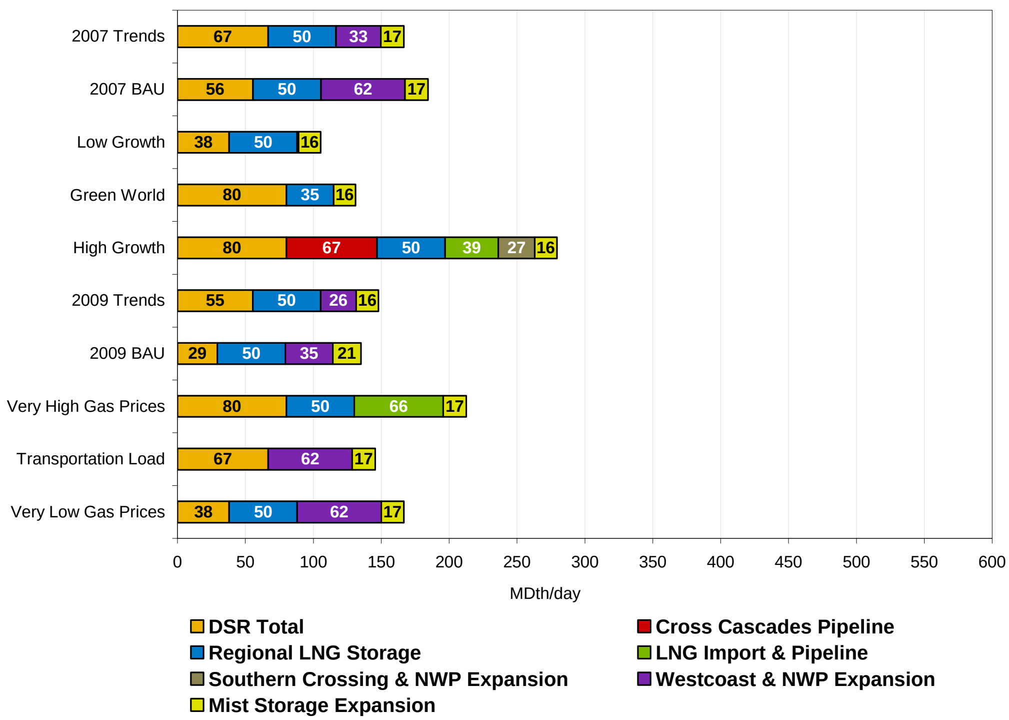
Figure 8-23
Customer Segment Contributions to DSR



Regional LNG Storage

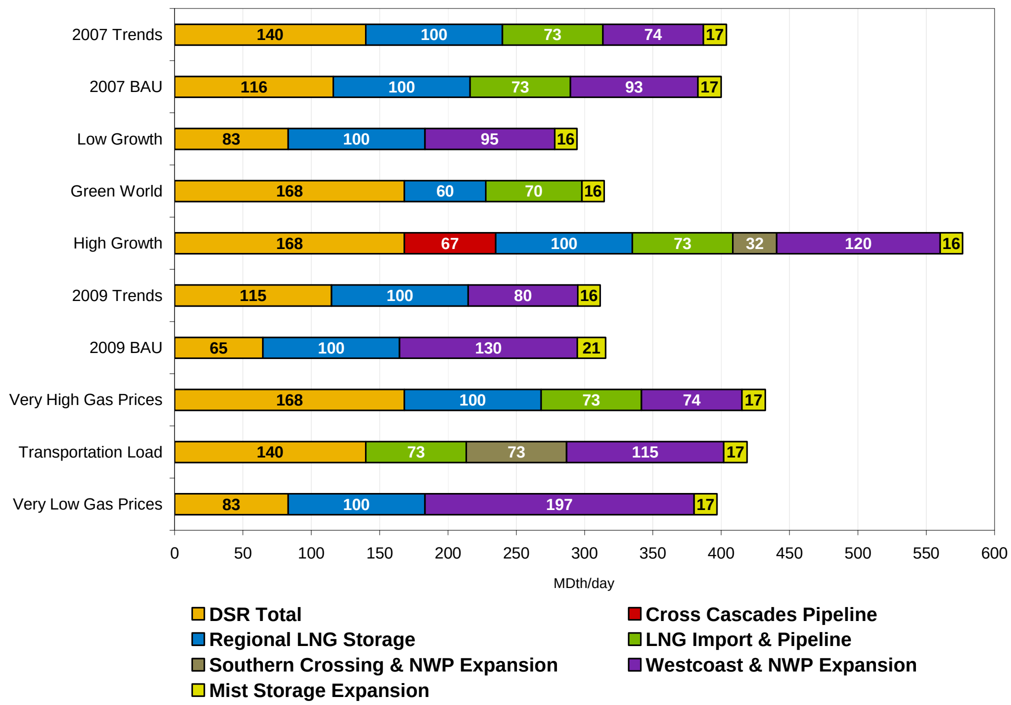
The gas sales plan includes 50 MDth per day of regional LNG storage capacity in 2017, and an additional 50 MDth per day of capacity appeared to be a least cost resource addition by 2022. (If a major Rockies pipeline expansion were developed, these resources would most likely not be required.) Addition of the first 50 MDth of LNG storage in 2017 is a robust decision across the analysis. Figure 8-24 illustrates that this alternative was selected as part of the least cost portfolio in nearly every planning scenario. The Monte Carlo analysis described in Chapter 6 also demonstrated that this alternative was part of the least cost portfolio in 90% of the cases tested.

Figure 8-24
Gas Sales Resource Additions in 2020



Further ahead in the planning horizon, an additional 50 MDth of LNG storage is included, for a total of 100 MDth by the end of the planning period. Again, this appears to be a robust least cost resource addition across the various planning scenarios, as Figure 8-25 illustrates.

Figure 8-25
Gas Sales Resource Additions in 2029



Westcoast and Northwest Pipeline Expansion: Northern B.C. Gas Supply

The gas sales plan calls for a 30 MDth per day expansion of Westcoast/Northwest pipeline capacity in 2017, and an additional expansion of 32 MDth per day around 2026. Smaller, incremental expansions along this route appear more feasible than expansion to the Rocky Mountain basin at this time. Figure 8-25, above, illustrates that the addition of 30 MDth per day of capacity is a robust decision across the various planning scenarios. Notice that several of the portfolios that do not include this alternative also model demand-side resources at significantly higher annual penetration rates than PSE believes it can count on achieving. Monte Carlo results for the 2009 Trends scenario indicate that this alternative is selected in about 53% of the draws by December 2017.

Mist Storage and Pipeline Capacity

A relatively small amount of Mist storage and Northwest Pipeline transportation capacity – 16 MDth per day – is included in the gas sales plan. Figure 8-25, above, illustrates that a small amount of Mist would be part of the least cost portfolio in every planning scenario.

Alternatives Not Included in Gas Sales Plan

Although not included in the plan, three resources were shown to be least cost in some planning scenarios. They include: the addition of Cross Cascades pipeline capacity that would increase access to supplies in the Rocky Mountain basin; imported LNG with related Northwest pipeline capacity; and the Southern Crossing and related Northwest pipeline capacity. The company chose to follow the least cost analysis guidance for the 2009 Trends scenario with regard to these resources. The following briefly explains why they were excluded:

Cross-Cascades/Rockies Expansion. Supply diversity is a concern; however, analysis in this IRP did not fully explore the value of expanded access to the Rockies basin. PSE will continue to quantify the costs and benefits associated with such diversity and may adapt resource strategies if the company is able to make the assessment that a major Rockies expansion would be lowest reasonable cost.

Import LNG and Northwest Pipeline Expansion. This alternative does appear to be least cost in several of the planning scenarios shown in Figures 8-24 and 8-25, but the timing of the addition is sufficiently distant that we can wait to see if an LNG import facility becomes commercially operational, and whether natural gas prices will make this a cost-effective resource. So far, pricing assumptions in 2009 updates do not support such a judgment. PSE will continue to monitor market developments.

Southern Crossing and Northwest Pipeline Expansion. Similar to the Rockies pipeline expansion, this resource was only selected in scenarios that assumed high growth rates and when assumptions about other resource expansions had been met. This alternative would not provide as much supply diversity benefit as expansion to the Rockies.

Discussion of Combined Gas Resource Plan Decisions

The rationale for the development of the combined gas resource plan is very similar to the rationale for the gas sales plan. Since both plans incorporate the same gas price forecasts, and since these prices largely determine the delivered cost of gas, the same optimal level of DSR was selected for both plans. As a result, the same reduction in DSR acquisitions and equivalent increase in Westcoast/NWP pipeline capacity (15 MDth per day) were made as in the gas sales portfolio.

For the combined plan, a second change was made to the optimal SENDOUT results based on the final electric resource plan. Total CCCT generating plant additions were reduced from 1,375 MW to 1,100 MW, as shown in Figure 8-26, which reduces the amount of peak day gas required by about 47 MDth per day. This change occurs after 2020, and reduces Westcoast/NWP capacity at the same time.

Figure 8-26
Combined Portfolio Resource Additions
2009 Trends vs. Resource Plan

2009 Trends	**Additions in MDth/day**			
	Regional LNG Storage	**Westcoast/NWP**	**Mist Storage & Pipeline**	**DSR**
2012		50	50	14
2017	50	129		26
2022	50	19		27
2026		144		26
2029				22
Total Additions	**100**	**342**	**50**	**115**

Resource Plan	**Additions in MDth/day**			
	Regional LNG Storage	**Westcoast/NWP**	**Mist Storage & Pipeline**	**DSR**
2012		50	50	14
2017	50	129		26
2022	50	20		26
2026		111		20
2029				14
Total Additions	**100**	**310**	**50**	**100**

As with the gas sales analyses, the regional LNG storage and Mist Storage alternatives were robustly selected in almost all scenarios for the combined gas plan.

Additional Considerations: Costs

Figure 8-27 illustrates the total annual costs and 20-year net present values (NPVs) of the portfolios in the 2009 Gas Sales and Combined Gas Resource Plans. Note that the costs for generation fuel are included in the electric resource plan as well.

Figure 8-27
Total Costs for 2009 Gas Sales and Combined Gas Portfolios