Executive Summary

This Integrated Resource Plan (IRP) presents a long-term forecast of the lowest reasonable cost combination of resources necessary to meet the needs of Puget Sound Energy's (PSE) customers over the next 20 years. The plan was developed during a two-year period in which U.S. and global economic conditions changed drastically. As a result, the scenarios developed for this analysis cover a wide range of circumstances. In the spring of 2009, PSE developed new demand forecasts and scenarios that allowed the company to incorporate post-downturn information about economic conditions into our assumptions.

The plan presented here will change as circumstances change, and actual resource acquisitions will take place in the real – rather than the hypothetical – marketplace. But examining the long-term implications of our customers' energy needs every two years makes it possible to identify many challenges as they appear on the horizon, study them as they approach, and better prepare to meet them. Among the key insights from this planning cycle are the following:

Expiring contracts and retiring assets are the biggest driver of electric resource need over the next 10 years. Even with NO growth in demand for power, PSE will need to acquire 490 megawatts (MW) of generation capacity by 2012 in order to fill the void created by expiring purchased power agreements. Aging units are assumed to begin retiring by 2016, so decisions will need to be made about whether it is more cost-effective to replace or refurbish and maintain aging assets. Either choice will mean substantial infrastructure investment.

Acquiring demand-side resources – as much as possible, as soon as possible -- is still the best strategy for avoiding both costs and risks. Natural gas prices and potential carbon emission costs affect portfolio costs more than any other factors tested in this analysis. Because energy efficiency consumes no fuel and produces no emissions, it continues to prove a cost-effective resource over the long term, even though it is becoming more expensive to acquire.

As PSE's reliance on natural gas for electric generation increases, supply diversity grows more important. At present, almost 70% of the combined gas portfolio (gas used for retail sales and gas used for electric generation fuel) is sourced from the Western Canadian Sedimentary Basin (WCSB). Under existing contracts, and absent implementation of a diversification strategy, 100% of the gas used for electric generation will come from that basin within a few years. This concentration leaves PSE exposed to physical supply disruptions and WCSB price volatility, with less ability to diversify that price risk across other supply basins. Investigating alternatives to increase supply diversity is an ongoing priority.

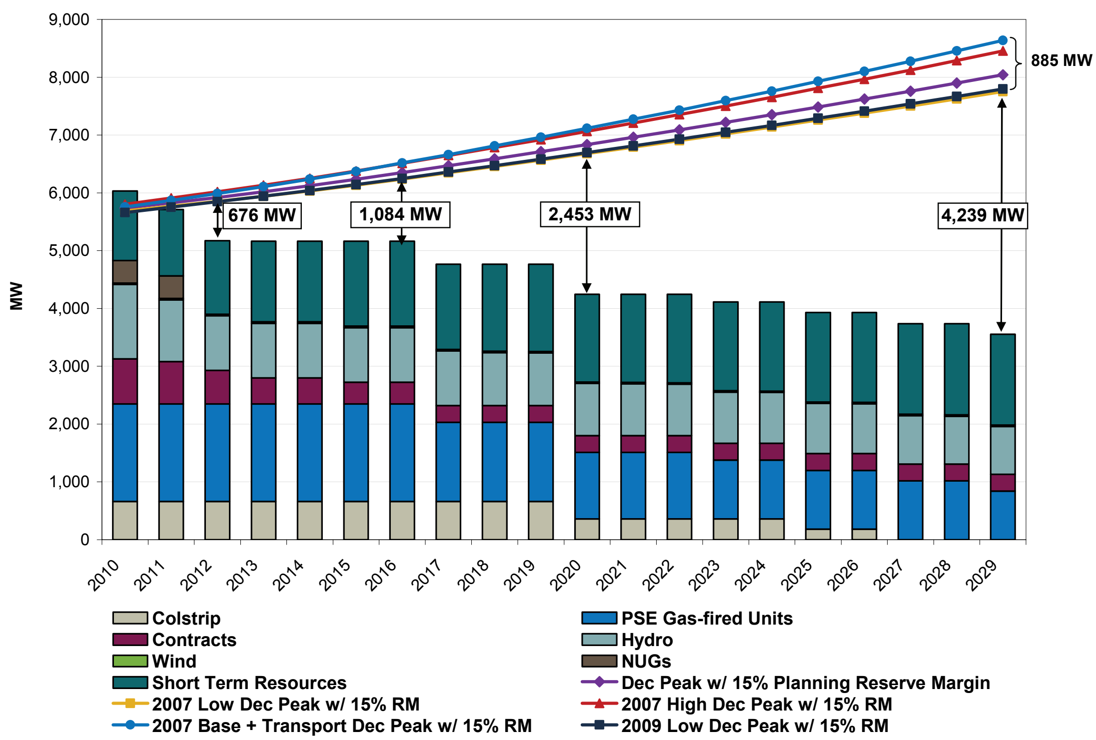
Consistent with prior resource plans, future energy costs are expected to increase and are highly uncertain. This IRP models a wide range of demand forecasts, gas prices, potential carbon dioxide (CO_2) costs, energy price volatility, and power plant costs. Overall, utility costs will continue to increase. In an environment in which both fixed and variable costs are rising, PSE will likely require regular rate increases as the utility system evolves to meet new legislative, compliance, and operational requirements, even if gas and purchased power prices remain low.

Additional renewable resources will be needed in the future. To meet renewable portfolio standards, this resource plan supports the same steady increase in renewable resources—assumed to be primarily wind—that PSE has shown in prior plans. Federal renewable portfolio standards and climate change legislation could change the amount of renewable resources required, and changing state and federal policies could also influence the types and locations of such resources. Notably, the same turbulent economic conditions that created the overall financial crisis may have also created opportunities to obtain development rights and renewable projects at substantial discounts compared to previous pricing, and some of these opportunities may offer long-term benefits to the utility and its customers.

Electric Resources

Electric Resource Need. (Figure 1-1) The company's electric resource outlook indicates the need for an additional 676 MW by 2012, 1,084 MW by 2016, and 2,453 MW by 2020 to meet customer demand.

Figure 1-1
Electric Peak Capacity Resource Need:
Comparison of Projected Loads with Existing Resources



Origins of Capacity Need. Expiring purchased-power contracts and the potential retirement of aging generation units contribute more to resource need than demand growth. For the first five years of the planning horizon, expiring contracts have the most effect; starting in 2016, resources decline as aging generating units begin to retire. Figure 1-2 shows how loads and resources, thus resource needs, change over time.

Figure 1-2
Drivers of Electric Capacity Need:
Expiring Resources Compared to Demand Growth

	2010	2012	Change from 2010	2020	Change from 2010	2029	Change from 2010
2009 Low Load Dec Peak w/ 15% RM	5660	5847	186	6697	1037	7,796	2135
Total Resources	6034	5171	(864)	4244	(1790)	3,556	(2478)
Total Need/(Surplus)	(374)	676		2453		4239	

Total Resources include 1200-1500 MW of Short-Term (<3 year) Market Purchases

Assumptions about the timing of resource retirements in this IRP are based on a depreciation study completed in 2006. The study established possible retirement dates based on typical operating lives as well as individual considerations for each unit. Analysis on whether to extend the useful life of existing assets is not incorporated in this IRP, but this information does highlight that the company will need to consider such decisions in the coming years.

Electric Resource Plan. Figure 1-3 illustrates the electric resource plan, displayed in terms of capacity. The line rising to the right represents peak customer demand. The bars below show the resources with the lowest reasonable portfolio cost used to meet that need. The table below shows the corresponding capacity builds. Because wind contributes only 5% of its capacity to meet peak, it is barely discernable on the chart in Figure 1-3. The table in Figure 1-4 lists the nameplate capacity additions by resource type included in the resource plan.

Options for resource additions remain limited. Wind is, generally speaking, still the only renewable resource capable of economically generating utility-scale power for PSE. New hydroelectric projects are not feasible at this time. Nuclear projects are unlikely to gain approval, and coal remains constrained by legislative restrictions and environmental concerns. Therefore, the plan recommends additional wind resources to fulfill renewables requirements, as much demand-side resources as possible (38 aMW per year for the first 11 years), and more natural gas-fired generating plants to fill the remainder of need.

Figure 1-3
Peak Capacity Electric Resource Plan, 2009 IRP
Cumulative Resource Additions (MW)

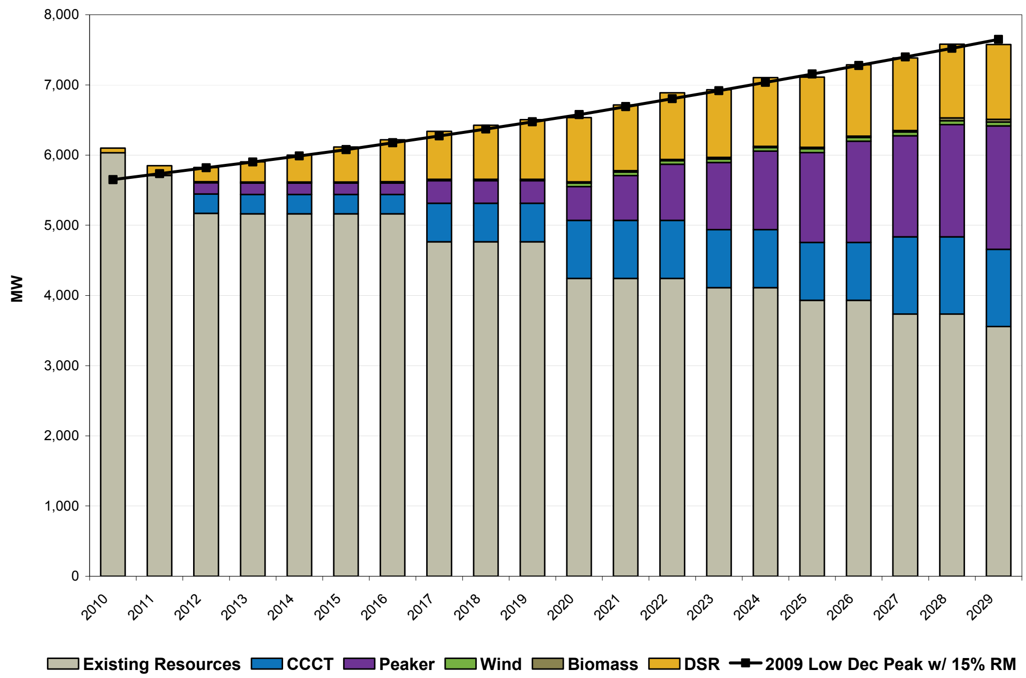
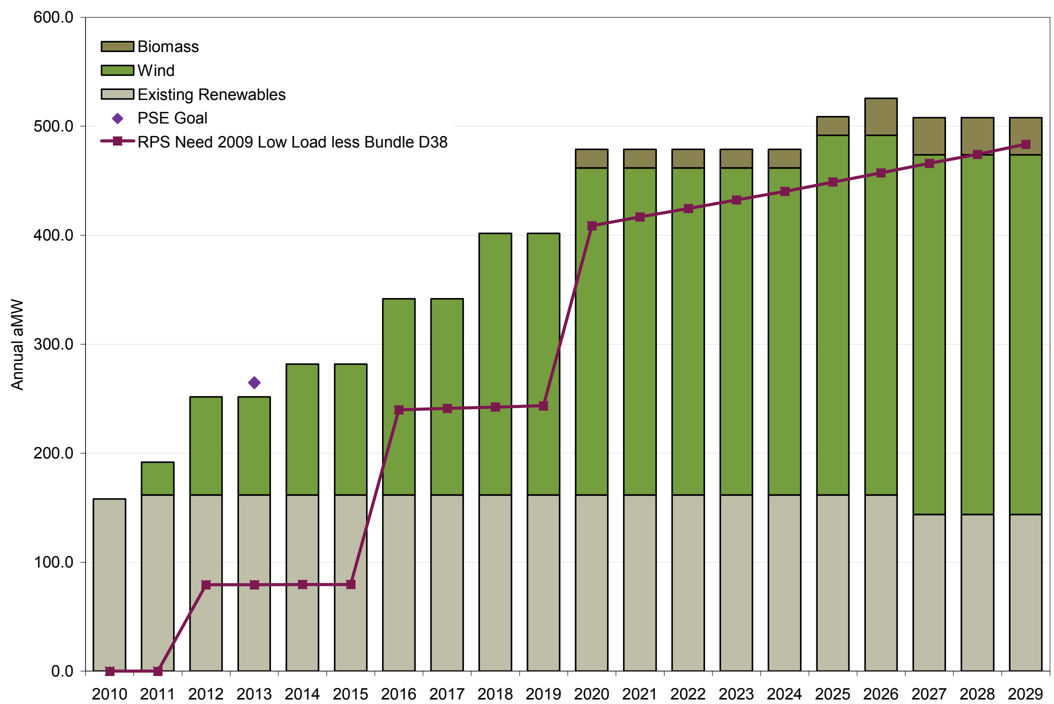


Figure 1-4
Cumulative Nameplate Resource Additions (MW)

	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, the 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 accelerate acquisition of wind resources relative to minimums established by the RPS, but Figure 1-5 illustrates the resource plan does not quite achieve that 10% goal—the IRP cost effectively reaches 9% by 2013 under current assumptions.

Figure 1-5
Renewable Resources in the Resource Plan
(Annual Average MWh)



[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.

Looking Ahead

- Reliance on natural gas to fuel electric generation will continue to increase until other options become available.
- PSE will continue aggressive pursuit of geothermal, biomass, and solar technologies, but until those technologies develop the capability to produce economic, utility-scale power, wind will remain PSE's primary renewable resource.
- Acquiring the wind resources needed to meet renewables requirements has required changes in PSE's acquisition strategies that are likely to persist into the future. Until recently, independent developers were willing to sell PSE completed or ready-to-build wind facilities. In the last couple of years and prior to the current financial crisis, developers adopted a business model of developing projects to own, with the intent of selling their portfolio at an attractive profit. In furtherance of that model, developers became more focused on power purchase agreements, which are generally less attractive to utilities. With the financial crisis and the tightening of credit markets, the ability of developers to complete projects has been compromised. As a result, in order to meet renewable resource requirements, PSE has entered the development process earlier than we did in the past. We will probably do the same for natural gas generation resources as well, given the scarcity of independently owned resources remaining in the region. This means that PSE will be forced to take on more development risk than in the past to meet the needs of our customers.
- Finally, consideration of whether it is more cost effective to replace or refurbish and maintain older generation units needs to be addressed in PSE's resource acquisition and planning process.

Natural Gas Resources

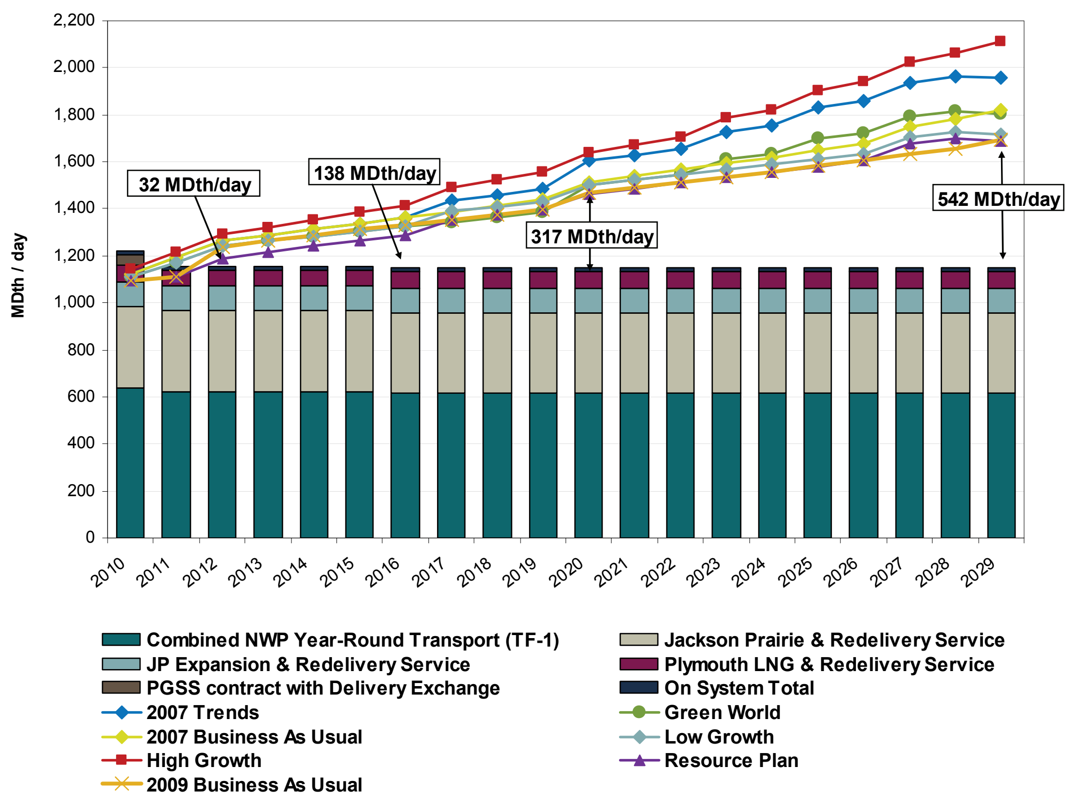
Reliance on natural gas continues to grow. In addition to the approximately 750,000 gas retail customers PSE serves, natural gas now fuels approximately 30% of electric generation. By 2029, it is projected to fuel 66% of electrical generation on an annual basis. Fuel for electric generation is now the primary driver of PSE's overall gas resource acquisitions, even though the total amounts required for generation remain lower than the total amounts needed for retail gas sales.

Because of this increasing dependence, we believe that looking at the total resource need for natural gas ("gas sales" and "gas for generation" combined) presents a more comprehensive picture of the challenges ahead and the decisions that must be made. Therefore, a plan for meeting the total gas needs of the utility is the focus here. (Separate gas sales and combined gas resource plans are presented in Chapter 8.)

Figure 1-6

Total Gas Resource Need (Gas Sales and Gas for Generation)

Projected Peak Demand Compared to Existing Resources



Origins of need. Different uses are driving natural gas need at different points on the timeline. Figure 1-7 identifies how each use (gas for retail sales and gas for electric generation), contributes to overall need. Gas for generation is the most immediate and pressing need for approximately the first five years of the planning horizon; additions for this purpose are required starting in 2010. Gas sales need begins after the 2015-2016 heating season.

Figure 1-7

Origins of Natural Gas Need: Electric Generation and Gas Sales

	2012	2016	2020	2029
Gas Sales Need/(Surplus)	(91)	15	102	318
Gas for Generation Need	123	123	215	224
Combined Need	32	138	317	542

Gas resource plan. Figures 1-8 and 1-9 show the lowest reasonable cost capacity expansion plan to meet PSE's total gas needs. PSE's plan to meet the total gas needs of our customers in 2012 calls for increased pipeline capacity for transportation of gas from northern British Columbia to our service area, the addition of Mist storage capacity, and aggressive levels of demand-side resources. By 2017, the plan calls for still more pipeline capacity, along with regional storage for liquefied natural gas (LNG), and additional demand-side resources. This plan does not include imported LNG. Eventually, imported LNG may become more cost effective than regional supplies, but in the near term, the better solution is to rely on regional storage and to expand access to areas with growing, competitively priced natural gas supplies. This can best be accomplished through investment in additional natural gas transportation infrastructure.

Figure 1-8

Combined Sales and Generation Fuel Resource Plan

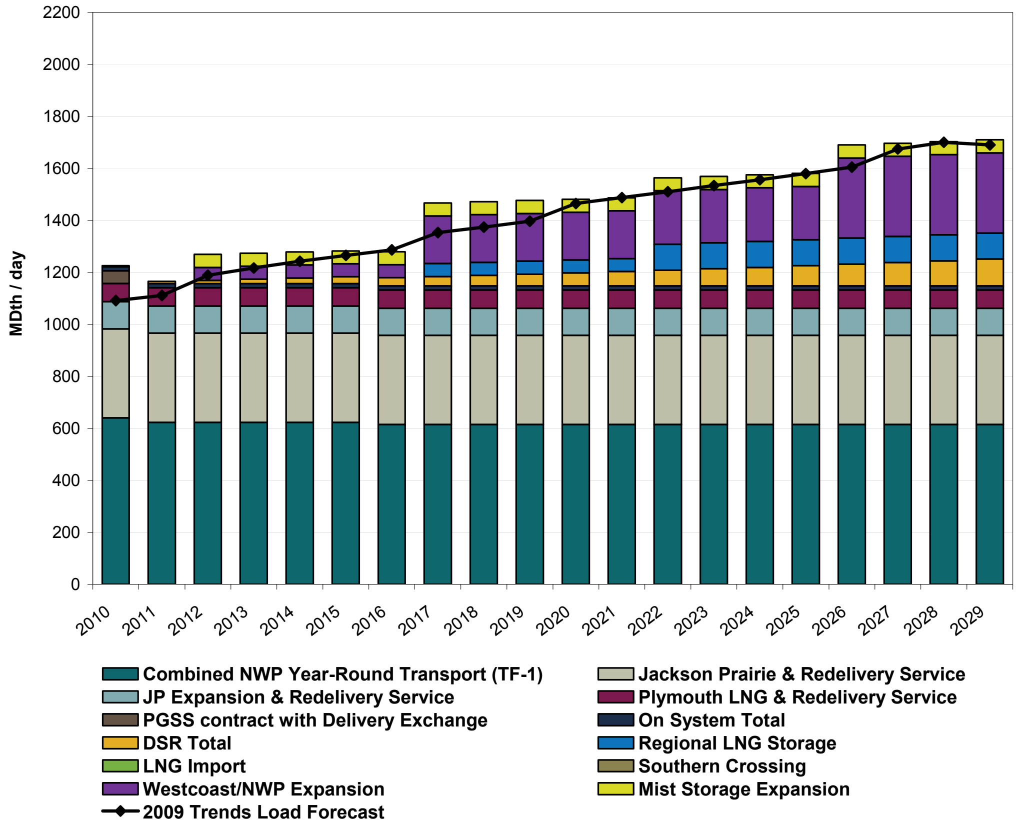


Figure 1-9

Combined Sales and Generation Fuel Resource Plan

	Additions in MDth/day				
	Regional LNG Storage	Westcoast/NWP	Mist Storage & Pipeline	DSR	Total Annual Additions
2012		50	50	14	114
2017	50	129		26	205
2022	50	20		26	96
2026		111		20	131
2029				14	14
Total Additions	100	310	50	100	560

At this point, the plan prescribes pipeline capacity additions from northern British Columbia, which meets total gas resource need at the lowest reasonable cost identified during this analysis, but which does not address the risks of increasing the reliance on a single supply basin for a crucial resource. Reliability and price exposure are the two major risks.

Concern about supply diversity will increase as PSE's reliance on natural gas increases in coming years. Currently, both the gas sales and electric generation fuel portfolios rely heavily on gas sourced from the Western Canadian Sedimentary Basin (WCSB), especially British Columbia.

- 65% of the gas sales portfolio comes from the WCSB, mostly from British Columbia, and
- 86% of the fuel for the generation portfolio comes from the WCSB, all of which comes from British Columbia. Further, the generation portfolio will become 100% reliant on British Columbia supplies in June 2011, when existing contracts for Rocky Mountain basin supplies expire.

Such a high concentration of natural gas supply from one source leaves PSE vulnerable to supply shortfalls should WCSB supply development not expand as projected, should supplies be diverted to Alberta markets, or should interruptions occur due to well freeze-offs, forced outages at processing plants, or pipeline disruptions. It also exposes PSE to WCSB price volatility and limits the company's ability to take advantage of cost differentials across different supply basins.

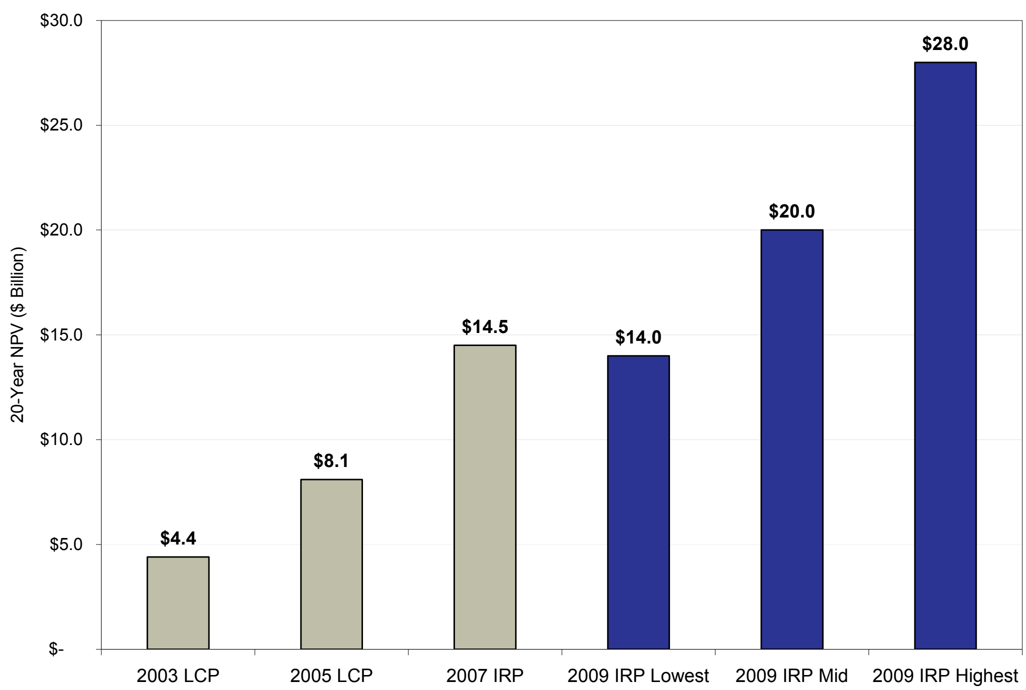
Increasing access to the Rocky Mountain basin may reduce these risks and increase the company's ability to take advantage of short-term price volatility, but the current analyses estimated that doing so at this time would increase costs. PSE will continue to investigate this issue. If the company is able to demonstrate that the benefits are greater than the costs, we will update resource strategies accordingly.

Energy Costs and Carbon Emissions

Electric Portfolio Costs—Higher and More Uncertain

Future estimates of incremental portfolio costs have increased in each resource plan since 2003. ("Incremental portfolio cost" refers to the variable cost of existing resources and the fixed and variable cost of new resources.) The range of portfolio costs projected in this IRP is extremely wide, as can be seen in Figure 1-10. Assumptions in the "highest cost" scenario produced portfolio costs that are fully twice those produced by the assumptions in the "lowest cost." Uncertainty about the future of natural gas prices accounts for approximately 60% of this difference. Uncertainty about the impact that cap and trade carbon regulation will have on energy costs and market prices accounts for most of the remainder. However, new regulation may also create carbon cost offsets; these potential offsets are not reflected in the costs shown below.

Figure 1-10
Rising and Uncertain Incremental Power Portfolio Costs

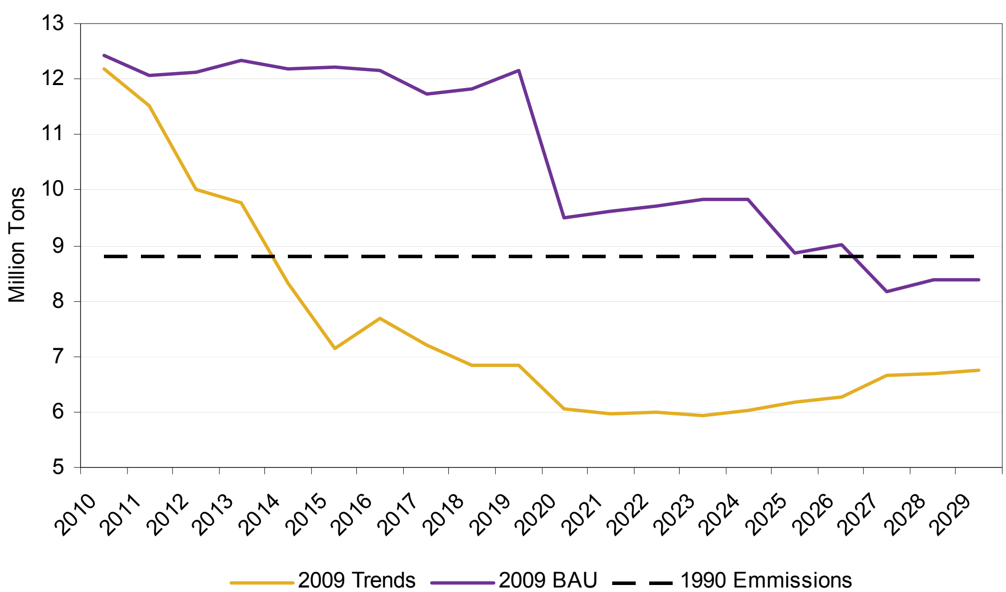


Electric Portfolio Projected Carbon Emissions

Carbon dioxide emissions are expected to fall in the future. Emissions from all portfolios fall below 1990 levels of 8.8 million tons per year by the end of the study period except for portfolios tested with no additional demand-side resources. While the imposition of carbon costs accelerates the reduction of carbon emissions, this is primarily a result of the assumed retirement of Colstrip units 1 and 2 in 2020. Figure 1-11 compares a portfolio that includes CO_2 costs of $37 per ton in 2012 rising to $130 per ton by 2029 (2009 Trends) with a portfolio that includes a negligible $0.32 per ton (2009 Business As Usual). In the 2009 Trends scenario, CO_2 emissions fall off much more quickly as carbon costs reduce the economic dispatch of PSE's Colstrip units significantly—with capacity factors in the range of 20%. Such carbon prices would reduce emissions, but how would it affect costs, as low cost generating resources are replaced by higher cost resources? How or whether carbon allowances are distributed will have a significant impact on carbon prices and the total costs to customers. Each iteration of proposed carbon regulation brings with it a different, complex allocation process. If regulation that imposes carbon costs is ultimately enacted, this allocation process will be very important to costs that utility customers will bear.

Figure 1-11

Falling Carbon Emissions



Summary of Action Plans

The following is a summary of the Action Plans that are summarized in Chapter 9, Action Plans.

Electric Resource Action Plan

- Assessment of Resource Need: Continue to refine analysis of resource need, including further refinements in the capacity planning standard with regard to operating reserves. Also, PSE will consider alternatives to address its long-term reliance on short-term markets for firm capacity needs.
- Demand-Side Resources: Issue RFPs and work with external stakeholders in the CRAG process to develop program goals, targets, and tariff filings that enable PSE to continue to increase energy efficiency and other demand-side resource programs.
- Renewable Resources: Continue to work toward meeting renewable energy obligations. This will include using the formal RFP process, looking for market opportunities, and continuing to evaluate the strategy of moving deeper into the development process for renewables to maximize the cost effectiveness of renewable resource acquisitions for our customers.
- Thermal Resources: As with renewable resources, PSE will use the formal RFP process, look for market opportunities, and consider self-build alternatives for base load and peaking resources to maximize cost effectiveness of thermal resource acquisitions for our customers, and to ensure reliable and stable operation of the electric system.

Natural Gas Resource Action Plan

- Diversity of Supply and Pipeline Capacity Expansions: Continue to refine the assessment of benefits and costs of maintaining access to both Canadian and Rocky Mountain supply basins.
- Demand-Side Resources: Issue RFPs and work with external stakeholders in the CRAG process to develop program goals, targets, and tariff filings that enable PSE to continue to increase gas energy efficiency programs.
- LNG and Underground Storage Resources: Consider regional market opportunities and self-build alternatives for both LNG storage and underground storage, to maximize cost effectiveness of such storage resource acquisitions for our customers.