Electric Analysis

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More than a million customers in Washington state depend on PSE for safe, reliable, and affordable electric services. The IRP analysis described in this chapter enables PSE to develop valuable foresight about how resource decisions may unfold over the next 20 years in conditions that depict a wide range of possible futures.

1. Resource Need

For PSE, resource need has three dimensions. The first is physical: Can we provide reliable service to our customers at peak demand hours and at all hours? The second is economic: Can we meet the needs of customers across all hours cost effectively? The third is policy-driven: Are there enough renewable resources in the portfolio to fulfill the state's renewable portfolio standard requirements? Each dimension is described below.

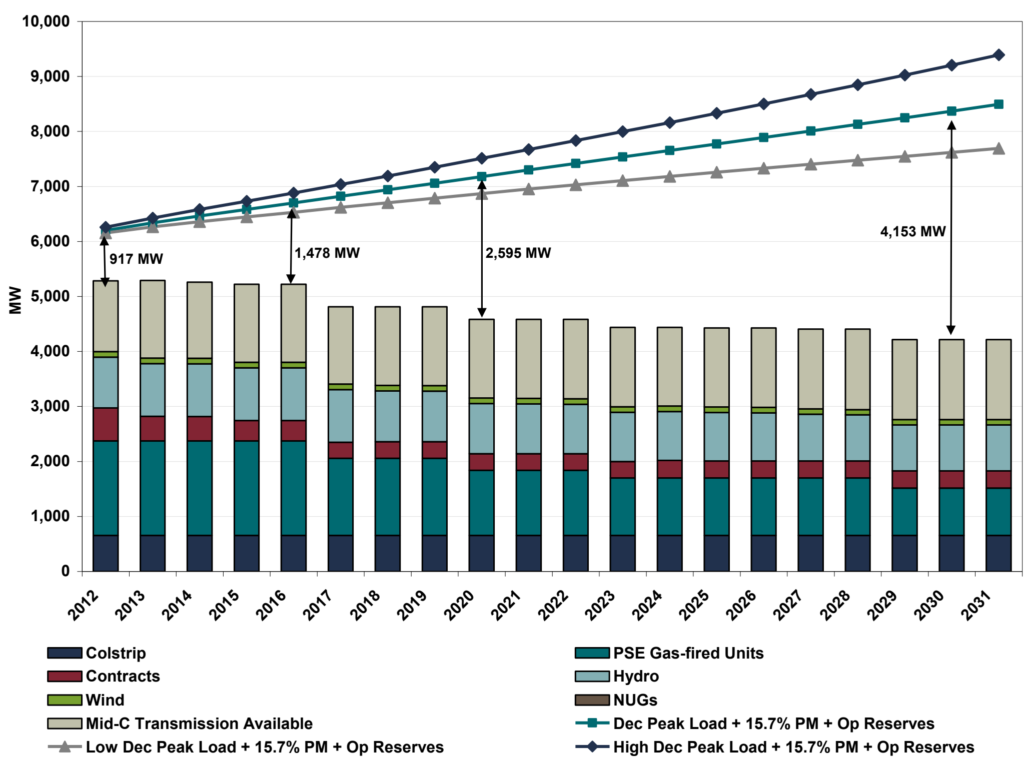
Physical Reliability Need

Physical reliability need refers to the resources required to ensure reliable operation of the system. This operational requirement has three components: customer demand, planning margins, and operational reserves. The word "load" – as in "PSE must meet load obligations" – specifically refers to the total of generated demand plus planning margins and operating reserve obligations. The reserves must be maintained in order to minimize interruption of service due to extreme weather or the unlikely event of equipment failure or transmission interruption.

Physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak-hour capacity metric through a loss of load probability analysis. That is, if PSE has sufficient resources modeled in the IRP to meet its normal peak hour demand plus a 15.7% planning margin and the operating reserves required to dispatch those resources, the company will be able to maintain an adequate level of reliability across all hours. We can simplify physical resource need in this way because PSE is much less hydro-dependant than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If we were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources/contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons

Figure 5-1 shows physical reliability need for the three demand scenarios modeled in this IRP. The components of this "peak need" are described more fully following the chart.

Figure 5-1
Electric Peak Need (Physical Reliability Need)
Comparison of projected peak hour need with existing resources



Demand. PSE uses national, regional, and local economic and population data to develop a range of demand forecasts for the 20-year IRP planning horizon.[1] These forecasts are incorporated into the scenarios modeled in the electric analysis. (See Chapter 4 and Appendix H for a complete description of the forecasting methodologies and inputs used in demand forecasting.)

PSE is a winter-peaking utility, meaning that we experience the highest end-use demand for electricity when the weather is coldest, so projecting peak energy demand begins with a forecast of how much power will be used at a temperature of 23 degrees Fahrenheit at SeaTac (a normal winter peak for PSE). We also experience sustained strong demand during the summer air-conditioning season, although these highs do not reach winter peaks.

Planning margin. PSE incorporates a 15.7% planning margin in its description of resource need in order to achieve a 5% loss of load probability (LOLP). The 5% LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.[2] The process has two steps. First, we perform an analysis on the likelihood that load will exceed resources on an hourly basis over the course of a full year. Included are uncertainties around temperature impacts, hydro conditions, wind, and forced outage rates (both their likelihood and duration). This analysis allows us to identify the amount of resources needed to achieve a 5% LOLP. In step two, the 5% LOLP is translated into the planning margin of 15.7%. The calculations used to determine the planning margin are described in Appendix I, Electric Analysis.

Operating reserves. North American Electric Reliability Council (NERC) standards require that utilities maintain a "reserve" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool, therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves.

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[1] *The demand forecasts developed for the IRP are necessarily a snapshot in time, since the full IRP analysis takes more than a year to complete and this input is required at the outset. Forecasts are updated continually during the business year, which is why those used in acquisitions planning or rate cases may differ from the IRP.*

[2] *See* http://www.nwcouncil.org/library/2008/2008-07.htm

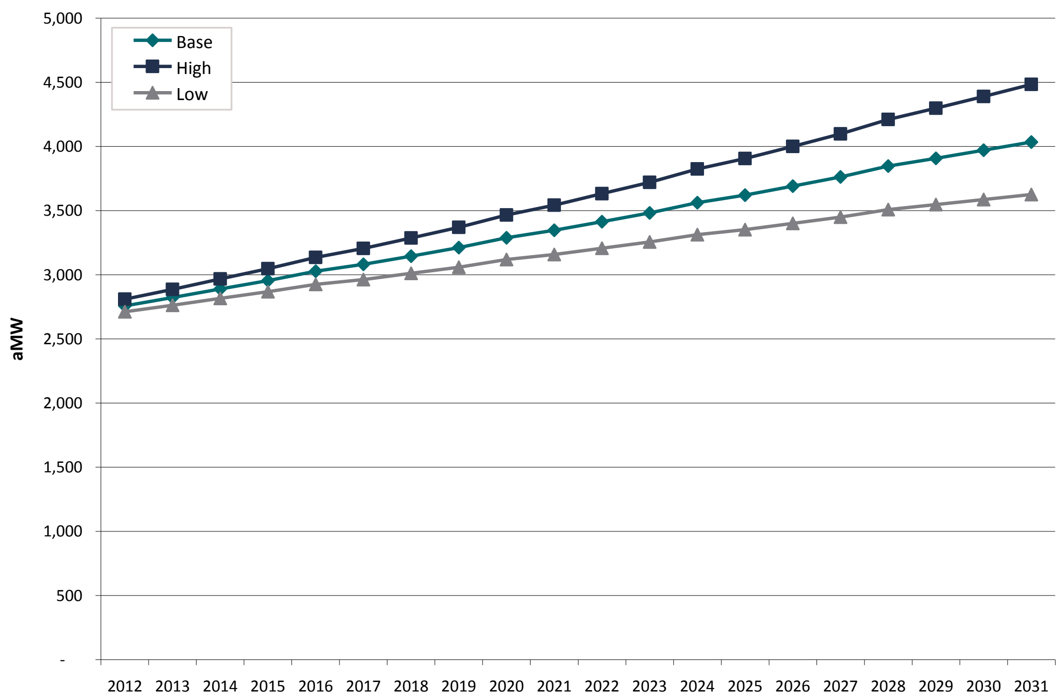
Contingency reserves. Contingency reserves are intended to bolster short-term reliability in the event of forced outages. Under the Northwest Power Pool's contingency reserve sharing agreement, generators must reserve an additional 5% of hydro or wind resources and 7% of thermal resources, when such units are dispatched to meet firm sales obligations. This capacity must be available within 10 minutes, and 50% of it must be spinning. For example, if a 100 MW thermal generator is dispatched to meet firm sales, the utility must have an additional 7 MW of resources available to meet the contingency reserve sharing obligation. Each member of the power pool maintains such reserves. If any member's generator experiences a forced outage, the contingency reserve sharing agreement is activated. Reserves from other members come online to make up for the lost generation. This is a very short-term arrangement. Contingency reserve sharing covers such forced outages for up to one hour. After that, the utility must balance its load (firm sales plus operating reserves) by either purchasing resources on the market or, if necessary, shedding load.

Regulating reserves. Utilities must also have sufficient reserves available to maintain a constant frequency on the system; in other words, they must be able to ramp up and down as loads and resources fluctuate instantaneously. For PSE, this amount is 35 MW. Regulating reserves do not provide the same kind of short-term, forced-outage reliability benefits as contingency reserves; they include frequency support, load forecast error, and actual load and generation changes.

Energy Need

Meeting customers' "energy need" is more of a financial concept that involves minimizing cost rather than a physical planning constraint for PSE. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically. We do not have to constrain (or force) the model to dispatch resources that are not economical; if it is cheaper to buy power than dispatch a generator, the model will choose to buy. Similarly, if a zero (or negative) marginal cost resource like wind is available, the model will displace higher-cost market purchases and use the wind to meet the "energy need." Figure 5-2, below, illustrates the company's energy need into the future, based on the energy load forecasts presented in Chapter 4.

Figure 5-2
Annual Energy Need



Renewable Resources

Washington state's renewable portfolio standard (RPS) requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. The main provisions of the statute (RCW 19.285) are summarized below.

Washington State RPS Targets

- 3% of supply-side resources by 2012
- 9% of supply-side resources by 2016
- 15% of supply-side resources by 2020

For all practical purposes, wind remains the main resource available to fulfill RPS requirements for PSE. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances, and other renewable technologies are not yet capable of producing power on a large enough scale to make substantial contributions to meeting the targets.

Renewable resources influence supply-side resource decisions.

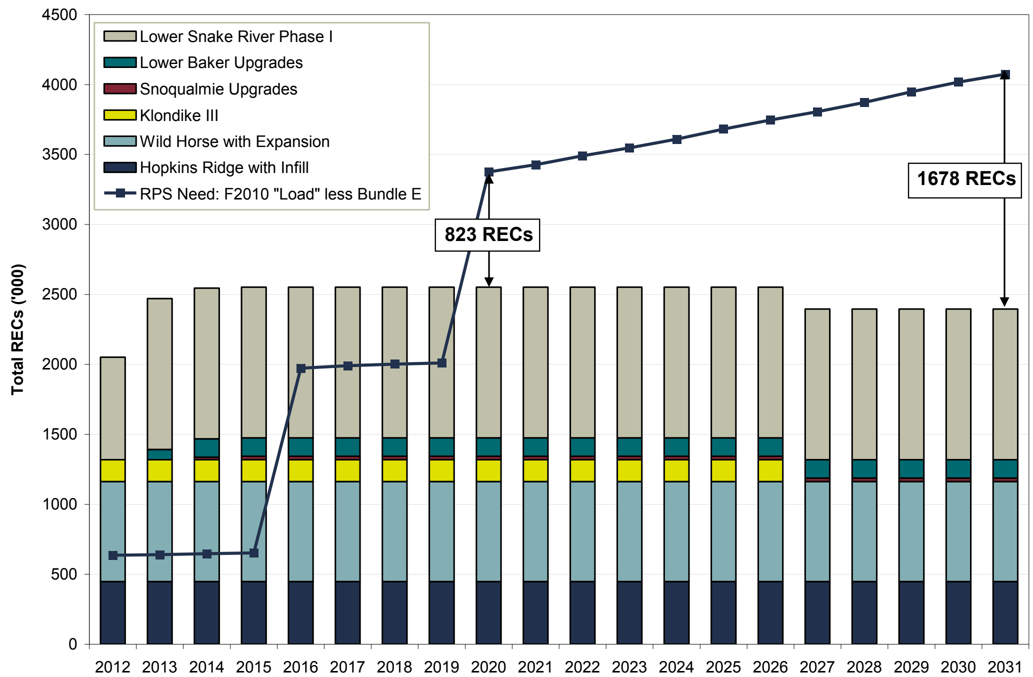
Adding wind to the portfolio increases the need for stand-by back-up generation that can be turned on and off or adjusted up or down quickly. The amount of electricity supplied to the system by wind drops off when the wind stops, but customer need does not. As the amount of wind in the portfolio increases, so does the need for reliable back-up generation. Appendix G discusses PSE wind integration challenges in more detail.

Demand-side achievements affect renewable amounts.

Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of the supply-side resources used to meet load; therefore, if the amount of supply-side resources decreases, so does the amount of renewables we need to plan for. Achieving demand-side resources (DSR) has precisely this effect: DSR decreases the amount of supply-side resources needed, and therefore the amount of renewables needed.

Figure 5-3 illustrates the need for renewable energy after accounting for the savings from demand-side resources that were found cost effective for the 2011 IRP.

Figure 5-3
RPS Need Based on Achievement of All Cost-effective DSR



2. Resource Alternatives

Resources are divided into two categories, depending on where they originate. Supply-side resources originate on the company side of the meter, while demand-side resources (DSR) generally originate on the customer side of the meter.

With supply-side resources, power is generated by means of water, natural gas, coal, wind, etc., and then transmitted (or "supplied") to customers.

Demand-side resources include energy efficiency measures, demand-response, and other techniques that reduce the amount of power customers need (or "demand") in order to operate their homes and businesses.

In order to test if current conditions make it economical, this IRP also models transmission combined with short-term market power purchases as a resource.

Power Purchase Agreements (PPAs)
PPAs are contracts of varying lengths for purchasing electricity in the market. The IRP did not evaluate PPAs as a resource alternative because costs and commitment terms are market-driven and known only at the time of the offer, so they are not possible to model over a 20-year period. However, when actual acquisitions are made and terms and conditions *can* be known, they will certainly be considered and evaluated as alternatives.

Thermal resources

Coal. The coal resources that are part of PSE's existing portfolio provide a low-cost, stable fuel source and resource diversity. However, additional coal resources were not modeled because of the emissions restrictions set forth in Washington state law RCW 80.80. The IRP does, however, consider one scenario in which our existing coal resource – the Colstrip generating plant in Montana – is no longer available to us.

Natural gas. Additional long-term coal-fired generation is not a resource alternative. RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal. New large-scale hydro projects would not practical to develop today. Therefore, natural gas generation is extensively modeled in this IRP analysis due to the following characteristics.

- Proximity. Gas-fired generators can often be located within or adjacent to PSE's service area, thereby avoiding costly transmission investments required for long-distance resources like coal or wind.
- Timeliness. Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind and run-of-the-river hydropower.
- Versatility. Gas-fired generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.
- Environmental burden. Natural gas resources produce significantly lower emissions than coal resources (approximately half the CO_2).

Three types of gas-fired generators are modeled in this analysis, because each brings particular strengths into the overall portfolio.

Combined-cycle combustion turbines (cccts). In CCCTs, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than simple-cycle turbines. CCCT plants currently entering service can convert about 50% of the chemical energy of natural gas into electricity. Because of their high thermal efficiency and reliability, relatively low initial cost, and low emissions, CCCTs have been the resource of choice for power generation for well over a decade.

Simple-cycle combustion turbines (peaker). Simple-cycle combustion turbines are better at serving peak need than CCCTs because they can be brought online more quickly. They also have lower capital costs. However, simple-cycles are less efficient and have higher heat rates, which make them more expensive to run.

> **"Peaker"** is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need.

Reciprocating engines (peaker). Like simple-cycle combustion turbines, they can be brought online quickly to serve peak loads. Unlike gas turbines, reciprocating engines demonstrate consistent heat rate and output during all temperature conditions. Generally these units are small and are constructed in power blocks with multiple units. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. The small size of the units allows a better match with peak loads thus increasing operating flexibility relative to the simple-cycle combustion turbine.

Thermal resources not modeled: nuclear. Development and construction costs for nuclear power plants are so much higher than the next highest baseload option as to be prohibitive to all but a handful of the largest capitalized utilities. In addition, permitting, public perception, and waste disposal pose substantial risks.

Transmission

In this IRP, PSE modeled additional transmission capacity plus market power purchases. We wanted to test whether adding additional transmission and purchasing market power at times of peak need would result in lower portfolio costs than adding other resources. We modeled the addition of 500 MW of transmission capacity. PSE currently relies on approximately 1,200 MW of transmission to acquire electric energy and capacity from the market; during the planning period, this increases to over 1,400 MW.

Renewable Resources

Hydroelectric. Hydroelectric resources are valuable because of their ability to follow load, and because they cost less relative to other resources. Although water is a renewable resource, existing hydroelectric may not be counted toward fulfilling Washington's RPS requirement unless it is an efficiency upgrade to an existing project; this IRP does reflect upgrades in Snoqualmie and Lower Baker that qualify under RPS rules. For new hydroelectric to qualify, it must be a low-impact, run-of-the-river project.

Wind. Wind energy is the primary renewable resource that qualifies to meet RPS requirements in our region due to wind's technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions, and large "utility" scale compared to other technologies. However, it also poses challenges. Because of its variability, wind's daily and hourly power generation patterns don't necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes it challenging to integrate into transmission systems.

Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already crowded and strained.

Biomass. Biomass fuels, fuels sources, and generation technologies vary widely. Fuels range from wood and agricultural field residues, to municipal solid waste and animal manure, to landfill and wastewater treatment plant gas. Most existing biomass in the Northwest is tied to steam hosts, typically in the timber, pulp, and paper industries, and use direct combustion or gasification technology. PSE has received several biomass proposals through its RFP process.

Renewable technologies not modeled for this IRP include solar, geothermal, tidal, long-haul wind, and unbundled REC contracts. At this time, these technologies are not capable of producing power on a scale and at a cost that would make sense for PSE customers. We completed the Wild Horse Solar Facility in 2008, a demonstration project that uses photovoltaic technology to produce electricity, and we continue to collect data from the facility to evaluate equipment performance and fit with our resource portfolio. We continue to monitor technology developments in geothermal as well, and entertain proposals for geothermal power projects. PSE has also supported two Northwest ocean energy studies, one tidal assessment and one wave demonstration project. Long-haul wind outside the Pacific Northwest was not modeled in this IRP. Analysis in the 2009 IRP demonstrated that the additional transmission costs for such resources rendered them uncompetitive with wind resources in Pacific Northwest; this finding was reinforced by analysis on actual resource/contract bids in the 2010 RFP process. Finally, unbundled REC contracts were not analyzed. Unbundled RECs are a form of a contract similar to PPAs. Just like other alternatives, if the acquisition process found unbundled REC contracts to be more cost effective and lower risk than self-building resources to comply with RCW 19.285, the company would pursue those alternatives. Our experience in the 2010 RFP process found very limited quantities of unbundled RECs available, but the Company will continue to consider such offers in the future acquisition processes.

Demand-side Resources

Energy efficiency measures. This label is used for a wide variety of measures that result in a smaller amount of energy doing the same work as a larger amount of energy. Among them are codes and standards that make new construction more energy efficient, retrofitting programs, appliance upgrades, and HVAC and lighting changes.

Demand-response. Demand-response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

Distributed generation. Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

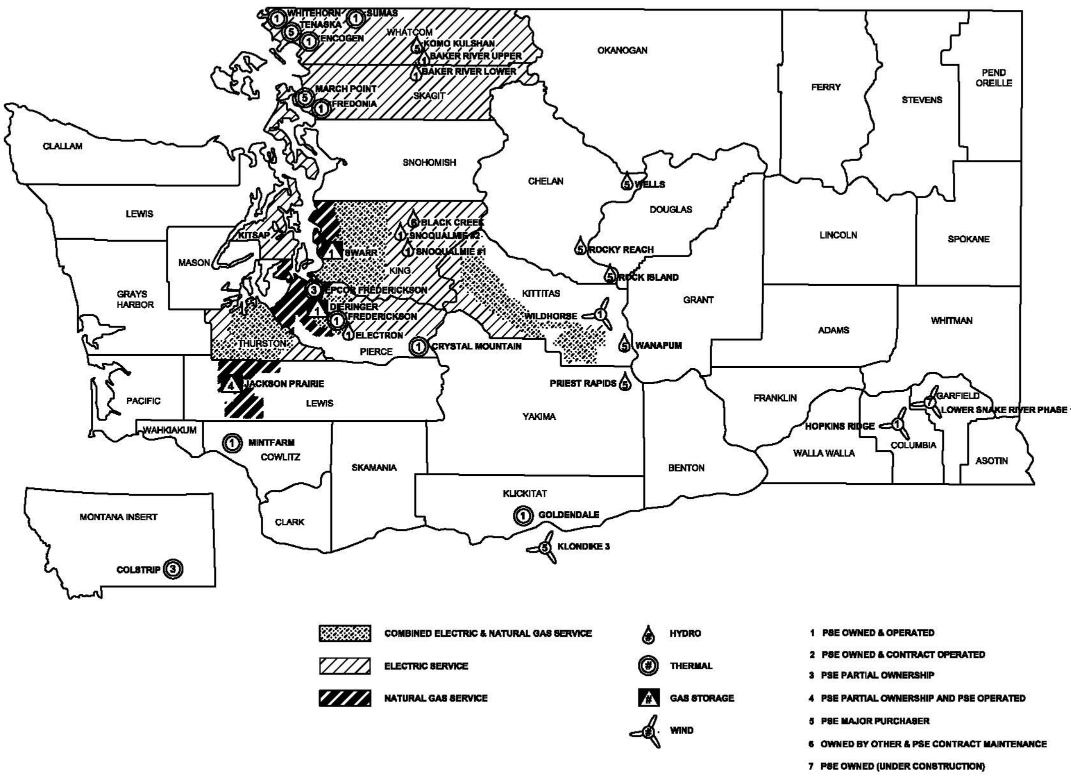
Distribution efficiency. This involves voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow losses that can reduce energy loss.

Summary of Existing Resources

Existing supply-side resources. To build the portfolios for the IRP analysis, we begin with a snapshot of PSE's existing resources. The map and tables that follow summarize PSE's existing resources and their expiration dates as of January 2011. The location of PSE's existing supply-side generation resources is pictured in Figure 5-4.

Figure 5-4

Location of Supply-side Resources



PSE's supply-side resources are diversified geographically and by fuel type. Most of the company's gas-fueled resources are in western Washington. The major hydroelectric contracted resources are in central Washington, outside PSE's service area. Wind facilities are located in central and eastern Washington. Coal-fired generation is located in eastern Montana.

Figure 5-5

Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NAMEPLATE CAPACITY (MW)[1]	EXPIRATION DATE
Upper Baker River	PSE	100	105	Not within study
Lower Baker River[2]	PSE	100	85	Not within study
Snoqualmie Falls[3]	PSE	100	49	Not within study
Electron	PSE	100	16	12/31/26
Total PSE-Owned			**255**	
Wells	Douglas Co. PUD	29.89	231	3/31/18
Rocky Reach	Chelan Co. PUD	25.0[4]	320	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0[5]	156	10/31/31
Wanapum	Grant Co. PUD	.64[6]	6	04/04/52
Priest Rapids	Grant Co. PUD	.64[6]	6	04/04/52
Mid-Columbia Total			**720**[7]	
Total Hydro			**975**	

Notes

1) *Nameplate capacity reflects PSE share only.*
2) *Lower Baker Unit 4 will be completed in March 2013, adding 30 MW of nameplate capacity to this project.*
3) *Snoqualmie Falls is offline until March 2013 for repairs. The new capacity will be 49 MW.*
4) *Rocky Reach share is 38.9% through October 2011 and 25% thereafter.*
5) *Rock Island I & II share is 50% through June 7, 2012, and then 25% beginning July 1, 2012.*
6) *Based on Grant Co. PUD current load forecast for 2010; our share will be reduced to this level in 2012.*
7) *As indicated in the above notes, several of the expiring Mid-C contracts have been renegotiated. Figure 5-5 reflects PSE's share, capacity and the expiration dates that will take effect between publication of this IRP and mid-2012 as a result of the new contracts. Individual resource and Mid-Columbia totals are rounded to the nearest megawatt.*

Figure 5-6
Coal, CCCT, and Wind Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)[1]	ASSUMED RETIREMENT DATE
Coal	Colstrip 1 & 2	50%	330	Not within study period
Coal	Colstrip 3 & 4	25%	386	Not within study period
Total Coal			**716**	
CCCT	Encogen	100%	159	Dec 2028
CCCT	Frederickson 1[2]	49.85%	129	Not within study period
CCCT	Goldendale	100%	261	Not within study period
CCCT	Mint Farm	100%	305	Not within study period
CCCT	Sumas	100%	121	Jul 2023
Total CCCT			**975**	
Wind	Hopkins Ridge	100%	157	Not within study period
Wind	Lower Snake River, Phase 1[3]	100%	343	Not within study period
Wind	Wild Horse[4]	100%	273	Not within study period
Wind	Klondike 3 PPA	0%	50	Nov 2026
Total Wind			**823**	

Notes

1) *Nameplate capacity reflects PSE share only. Ratings are at the following ISO conditions: ambient temperature 59˚ F, altitude 0 feet, atmospheric pressure 14.7 psia, relative humidity 60%, fueled by natural gas, 1000 BTU/SCF (HHV), and 900 BTU/SCF (LHV).*
2) *Frederickson 1 CCCT unit is co-owned with Capital Power Corporation - USA.*
3) *PSE began construction of Lower Snake River Phase I in spring 2010. Located in Garfield County, Wash., the 343 MW wind project is scheduled to be completed in the first or second quarter of 2012.*
4) *Wild Horse includes the original 229 MW wind project and a 44 MW expansion.*

Figure 5-7
Simple-cycle Combustion Turbines

NAME	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)[1]	ASSUMED RETIREMENT DATE
Fredonia 1 & 2	100%	208	Dec 2019
Fredonia 3 & 4	100%	108	Not within study period
Whitehorn 2 & 3	100%	149	Dec 2016
Frederickson 1 & 2	100%	149	Dec 2016
Total		**614**	

[1] Nameplate capacity reflects PSE share only. Ratings are at the following ISO conditions: ambient temperature 59˚ F, altitude 0 feet, atmospheric pressure 14.7 psia, relative humidity 60%, fueled by natural gas, 1000 BTU/SCF (HHV) and 900 BTU/SCF (LHV).

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydro, gas, waste products, and system deliveries without a designated supply resource. These contracts are summarized below. Short-term contracts negotiated by PSE's energy trading group are not included in this listing.

Figure 5-8
Long-term Contracts for Electric Power Generation

TYPE	NAME	POWER TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)[1]
NUG	Tenaska	Thermal	12/31/2011	245
NUG	March Point I	Thermal	12/31/2011	80
NUG	March Point II	Thermal	12/31/2011	62
Total NUG				**387**
Other Contracts	BPA- WNP-3 Exchange	System	6/30/2017	82
Other Contracts	Powerex/Pt. Roberts	System	9/30/2014	8
Other Contracts	BPA Baker Replacement	Hydro	10/1/2029	7
Other Contracts	PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Other Contracts	Canadian EA	Hydro	09/15/2024	-58
Other Contracts	Powerex	System	02/29/2012	150
Other Contracts	Shell Energy	System	03/31/2013	50
Other Contracts	RBS Sempra Commodities	System	03/31/2013	75
Other Contracts	Barclays Bank	System	02/28/2015	75
Total Other				**689**
Independent Producers	Twin Falls	Hydro	3/8/2025	20
Independent Producers	Koma Kulshan	Hydro	3/31/2037	14

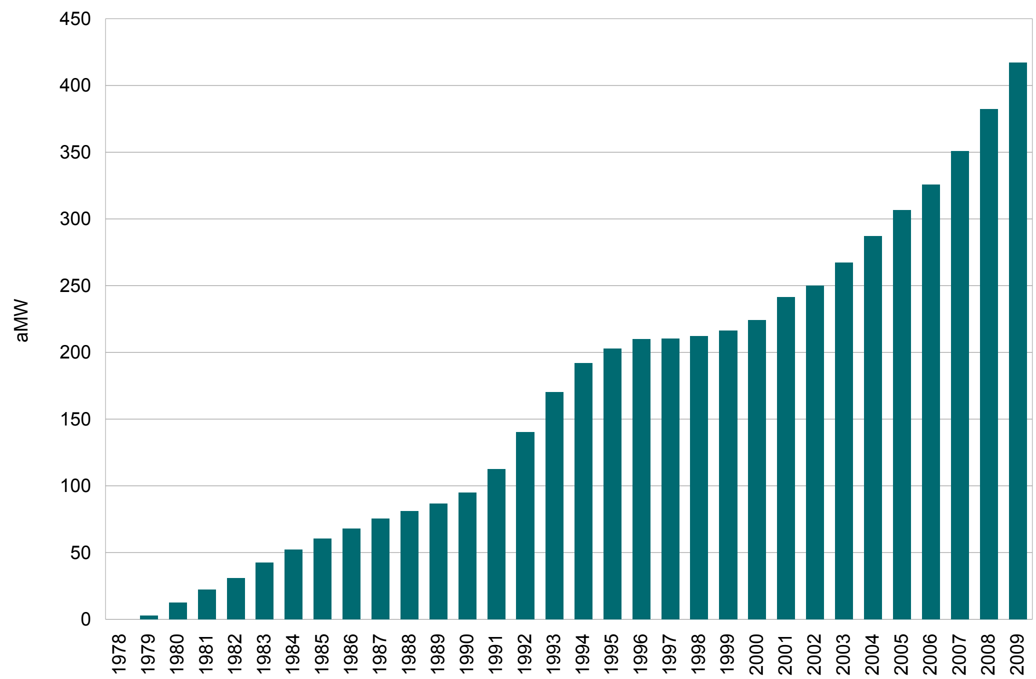
TYPE	NAME	POWER TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)[1]
Independent Producers	North Wasco	Hydro	12/31/2012	5
Independent Producers	Nooksack Hydro	Hydro-QF	01/01/2014	2.5
Independent Producers	Weeks Falls	Hydro	12/1/2022	4.6
Independent Producers	Hutchison Creek	Hydro-QF	9/30/2016	1
Independent Producers	Cascade Clean Energy-Sygitowicz	Hydro-QF	2/22/2014	<1
Independent Producers	Port Townsend Paper	Hydro-QF	06/30/09	<1
Independent Producers	VanderHaak Dairy	Biomass	12/31/2019	<1
Independent Producers	Qualco Dairy	Biomass	12/11/2013	<1
Independent Producers	Farm Power Lynden	Biomass	1/31/2019	<1
Independent Producers	Farm Power Rexville	Biomass	1/31/2019	<1
Total Independent				**49**

[1] *Nameplate capacity reflects PSE share only.*

Existing demand-side resources.

Demand-side resources are generally generated or saved on the customer side of the meter. While they include demand-response, fuel conversion, distributed generation, and distribution efficiency, energy efficiency measures are by far the most substantial contributor to resource need. During the 2008-2009 tariff period, the 66.4 aMW contributed by these programs amounted to enough energy to power approximately 50,000 homes. Between 1978 and 2009, gains of 363 aMW have accumulated on an investment of $650 million – more than the annual output from our share of Colstrip 1 & 2 and equivalent to the electricity used by about 270,000 homes for a year. As with supply-side resources, PSE evaluates energy efficiency programs for cost-effectiveness and suitability within a lowest reasonable cost strategy.

Figure 5-9
Cumulative Electric Energy Savings from DSR, 1978 to 2009



Our energy efficiency programs serve all types of customers—residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2008-2009 biennial program period concluded at the end of 2009; current programs operate January 1, 2010 through December 31, 2011. The majority of electric energy efficiency programs are funded using electric "rider" funds collected from all customers.

For the 2010-2011 period, a two-year target of approximately 71 aMW in energy savings was adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

Current electric energy efficiency programs.

The two largest programs offered by PSE to customers are the Commercial and Industrial Retrofit Program and the residential Energy Efficient Lighting Programs.

The Commercial and Industrial Retrofit Program offers expert assistance and grants to help existing commercial and industrial customers use electricity and natural gas more efficiently via cost-effective and energy efficient equipment, designs, and operations. This program gave out grants totaling more than $22 million to over 1,000 business customers in 2010 to achieve a savings of over 80,000 MWh.

The Energy Efficient Lighting Programs offer instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program provided incentives totaling more than $5 million, which resulted in the installation of over 2.2 million CFL lamps and fixtures in 2010 to achieve savings of over 56,000 MWh.

Figure 5-10
Annual Energy Efficiency Program Summary, 2008-2010
(Dollars in millions, except MWh)

Program	2008 - 2009 Actual	’08-’09 2-Year Budget./Goal	‘08/’09 Actual vs. ‘08/’09 % Total	2010 Actual	’10-’11 2-Year Budget./Goal	’10 vs. ‘11/’09 % Total
Electric Program Costs	$ 123,000,000	$ 130,000,000	95.0%	$ 75,000,000	$ 167,000,000	45%
Megawatt Hour Savings	581,000	513,000	113%	295,000	622,000	47.5%

Figure 5-10 shows program performance compared to two-year budget and savings goals for the biennial 2008-2009 electric energy efficiency programs, and records 2010 progress against 2010-2011 budget and savings goals.

During 2008-2009, electric energy efficiency programs saved a total of 66.4 aMW of electricity at a cost of $123 million. The company surpassed two-year savings goals while operating at a cost that was under budget. In 2010, these programs saved 32 aMW of electricity at a cost of $75 million. The average cost for acquiring energy efficiency in 2008-09 was approximately $210 per MWh, compared to a budgeted cost of approximately $270 per MWh in the 2010-2011 program cycle.

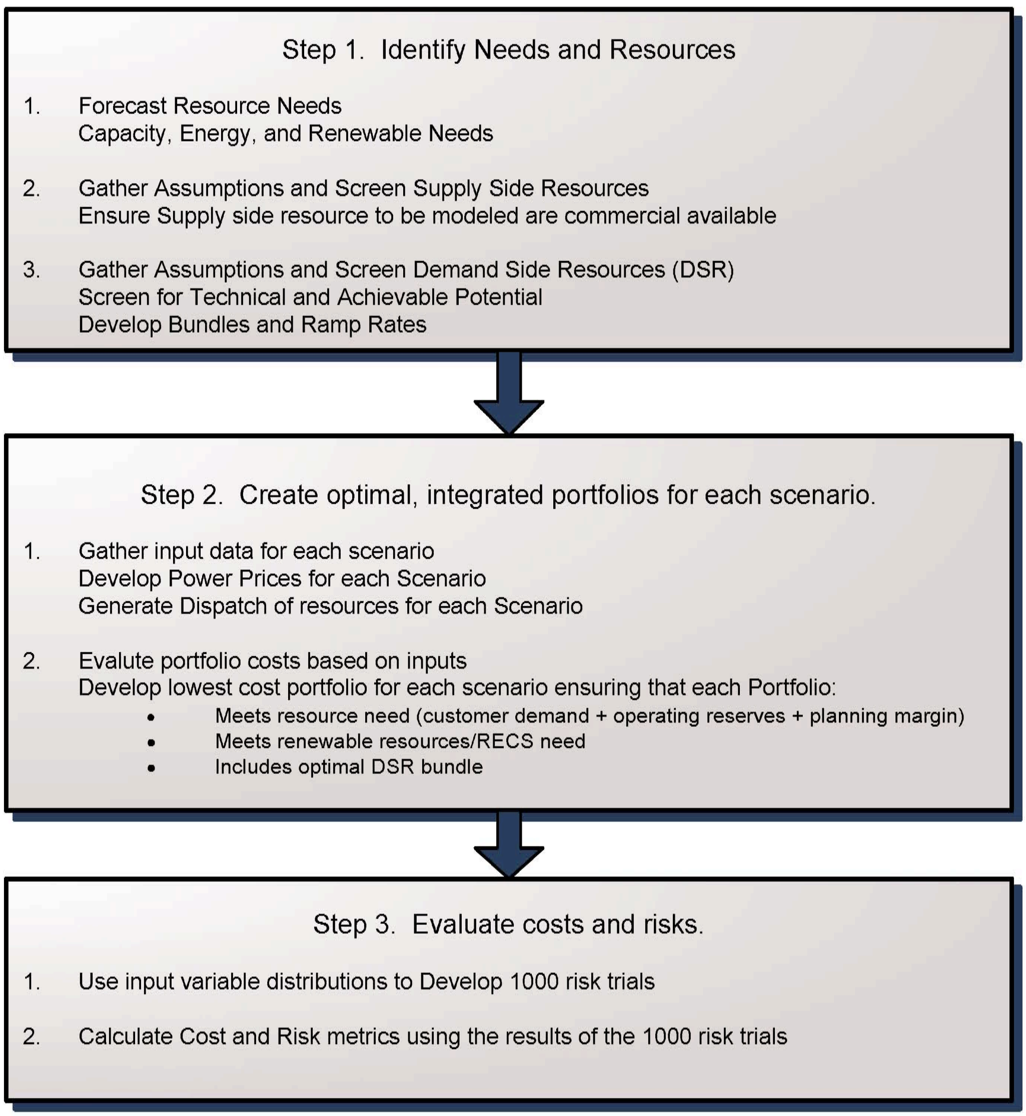
3. Analytic Methodology

This section describes the quantitative analysis of electric demand- and supply-side alternatives. It explains how portfolios were created in response to a variety of key economic assumptions expressed as scenarios, and how these portfolios were evaluated for cost and risk. The resulting analysis allowed the company to quantify how sensitive portfolios were to the planning assumptions, and provided insight into how adding different types of generation would affect PSE ratepayers' costs. Among the critical questions posed were the following.

- How might economic conditions and load growth affect resource decisions?
- What is the cost-effective level of energy efficiency?
- How sensitive are the demand-side portfolios to different levels of avoided costs?
- What are the key decision points and most important uncertainties in the long-term planning horizon, and when should we make those decisions?
- What impact might very different levels of natural gas prices have on resource decisions?
- How might future carbon regulation affect the relative value of resource alternatives?
- What carbon emissions are produced by portfolios under different scenarios?
- How do changes in financial incentive assumptions affect resource decisions?

Electric analytic methodology followed the three basic steps illustrated in Figure 5-11. (For a detailed technical discussion of models and methods, see Appendix I, Electric Analysis).

Figure 5-11
Methodology Used to Create and Evaluate Portfolios



Step 1: Identify needs and resources.

The analysis begins by using the most recently available forecast of customer demand. We use this load forecast to develop resource need assumptions.
Next, all resources that are available to fill unmet need are identified.

Supply-side resources included natural gas-fired generation, wind, and biomass.

Demand-side resource selection followed the three-step process illustrated in Figure 5-12.

- First, each demand-side measure was screened for technical potential.
- Second, a screen eliminated any resources not considered achievable.
- Finally, the remaining measures were combined into bundles based on levelized cost for inclusion in the optimization analysis.

Screening for technical potential assumed that all opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, load impacts, and markets could be surveyed.

To gauge achievability, we relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed economic electric energy efficiency potentials of 85% in existing buildings and 65% in new construction.

This methodology is consistent with the methodology used by the Northwest Power and Conservation Council. A comparison of the two can be found in Appendix B.

For a more detailed discussion of demand-side resource evaluation and the development of DSR bundles, see Appendix K, Demand-side Resource Analysis.

Figure 5-12

General Methodology for Assessing Demand-side Resource Potential

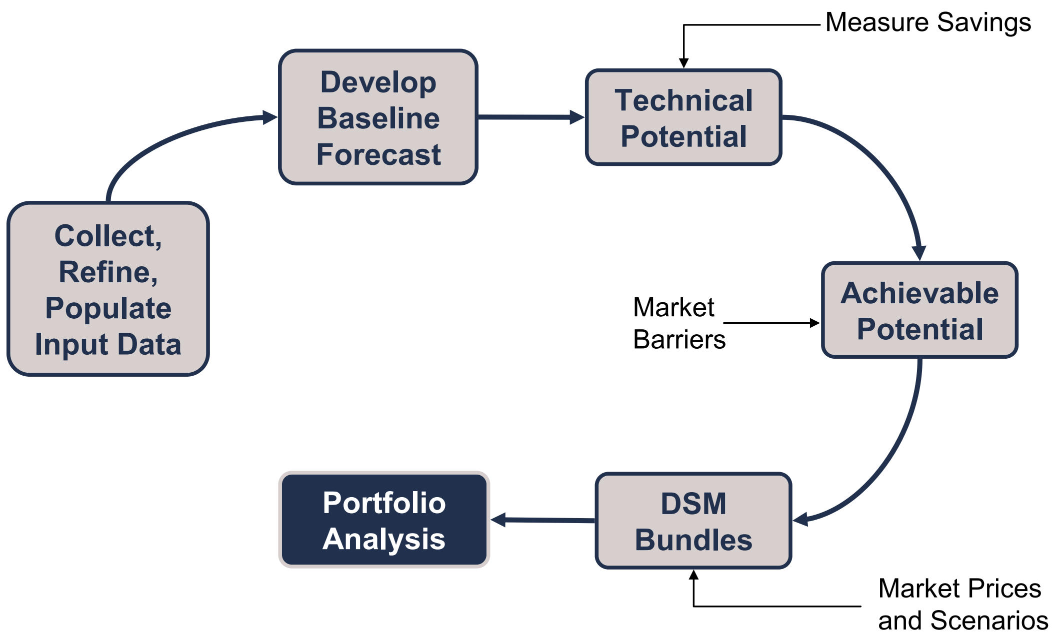
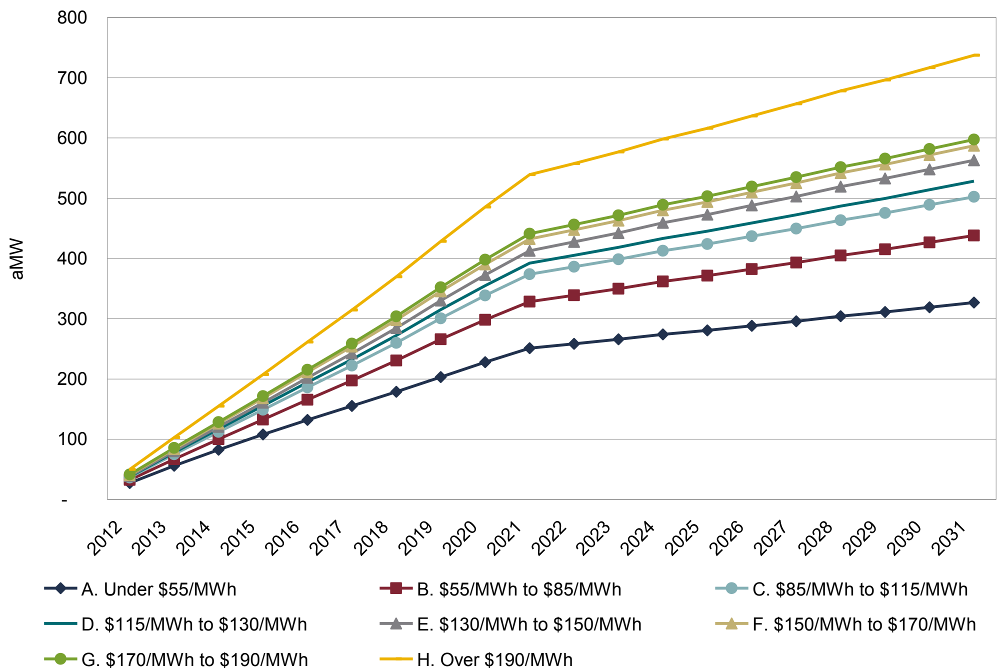


Figure 5-13 shows the achievable potential of all DSR bundles tested in the IRP. The effect of these bundles is to reduce load, so the costs of achieving the savings are added to the cost of the electric portfolios.

Figure 5-13

Achievable Technical Potential by Demand-side Cost Bundles (aMW)



Step 2: Create optimal, integrated portfolios for each scenario.

An optimal, integrated portfolio for each scenario and sensitivity was created using the portfolio optimization model PSM III to combine supply-side resources with the demand-side bundles. The optimization model used the inputs provided to identify the lowest cost portfolio that:

- Meets capacity need
- Meets renewable resources/RECS need
- Includes as much conservation as is cost effective

PSE models lowest cost from the customer perspective, so it is measured in as the lowest net present value (NPV) revenue requirement of a portfolio. To arrive at this calculation the company aligns three analytical efforts:

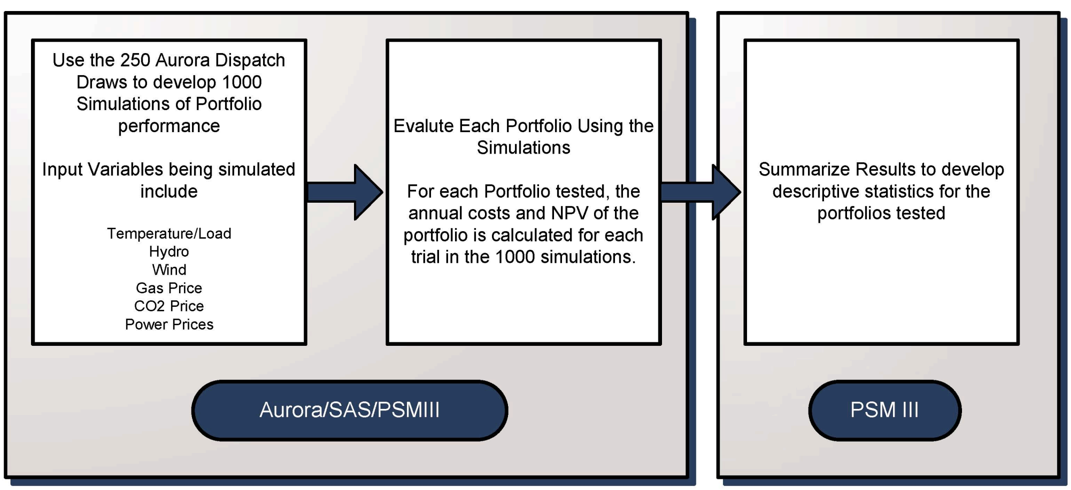
- An economic dispatch model that can provide a reasonable forecast of variable costs and wholesale market revenue from operating plants, given market assumptions. For this process, PSE uses Aurora.
- A revenue requirement model, to incorporate the costs of capital investments and other fixed costs the way customers will experience them in rates; the IRP uses the same financial model the general rate case uses for calculating revenue requirements.
- An optimization model, to develop and test different portfolios to find the lowest cost combination of resources; PSM III uses a linear optimization model.

Step 3: Evaluate costs and risks.

Once the optimal portfolio for each scenario was identified, PSE conducted risk analysis on select portfolios. The PSM III process illustrated in Figure 5-14 was used to calculate risk measures for each.

A Stochastic model was used to create 250 simulations of input variables for the Base Case scenario. The average, or expected, output from the 250 draws was used to find an optimal portfolio. We then fed the 250 draws into PSM III and used that tool to simulate 1,000 trials for the optimal portfolio. These trials allowed us to fully understand risks associated with differing gas prices, power prices, and weather conditions that affect loads, hydropower, and wind generation levels. For each trial, PSE could extract annual dispatch, costs, and loads for all the portfolios tested. (A full discussion of PSE's risk modeling approach appears in the "Stochastic Model" section of Appendix I, Electric Analysis).

Figure 5-14
Risk Analysis Process



4. Results

Figure 5-15 displays the MW additions for the optimal portfolios in 2016, 2020, and 2031. See Appendix I, Electric Analysis, for more detailed information.

Figure 5-15 below shows resource builds for the different scenarios. Note that with the exception of Green World all the portfolios end up looking very similar. The differences are described in the last section of this chapter.

Figure 5-15
Resource Builds by Scenario
Cumulative additions by nameplate

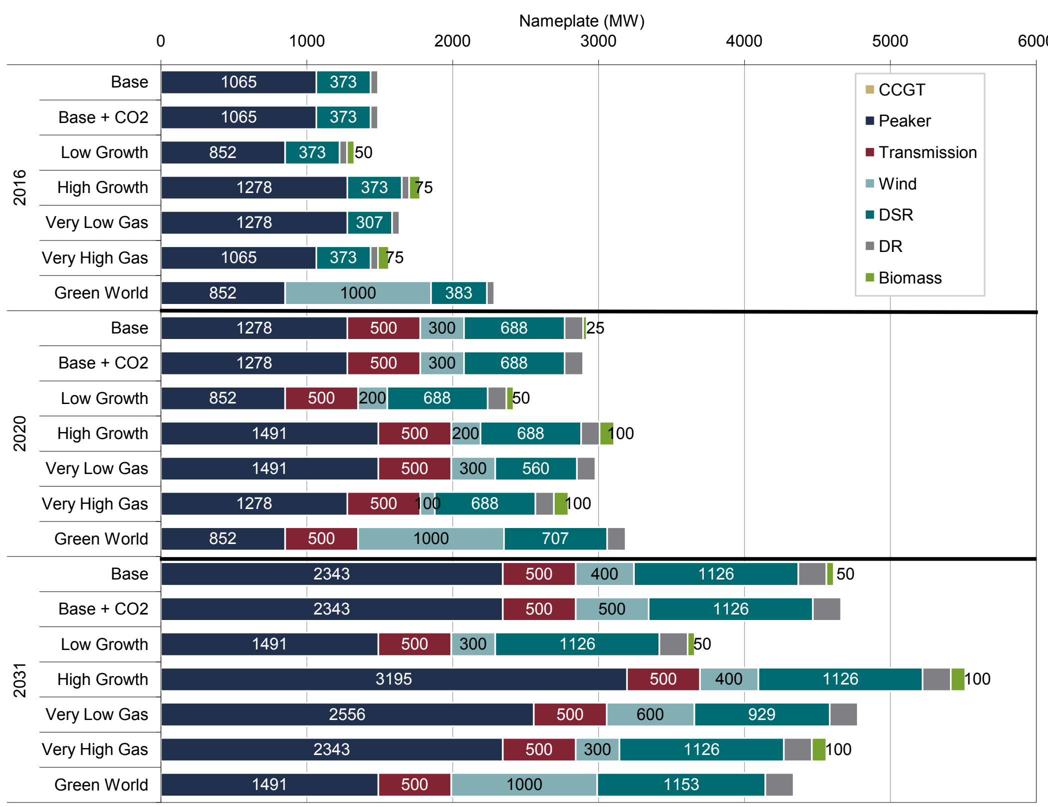


Figure 5-16 shows the 20-year net present value of costs for each of the portfolios.

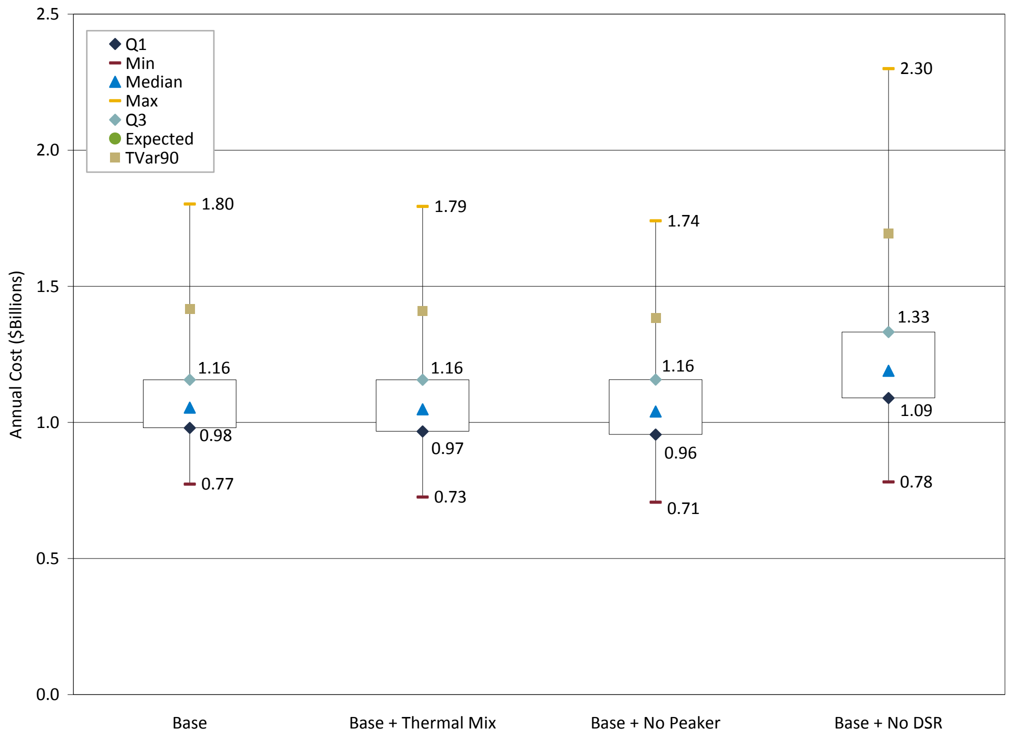
Figure 5-16
Net Present Value Expected Portfolio Cost

Scenarios	20-year NPV Expected Cost (Incremental Rev Req $Billions)
Base	$13.36
Base + CO2	$15.93
Low Growth	$9.83
High Growth	$18.58
Very Low Gas Prices	$10.87
Very High Gas Prices	$16.45
Green World	$21.06

NPV of costs shown above in Figure 5-16 represent the expected value of the least cost portfolio based on a comprehensive set of stochastic analyses. Results of the stochastic analysis can also be examined. Figure 5-17 represents the variability and the range of the portfolio costs of a few different portfolio sensitivities in the Base Case scenario. The different portfolios were designed to test cost versus risk trade-offs of demand-side resources and substituting combined cycle plants for some or all of the peakers (the peaker/CCCT portfolios are described in more detail below in the Key Findings and Insights section.) Figure 5-17 demonstrates that going from the No DSR portfolio to the Base portfolio—or any other portfolio—reduces both costs as well risk measured by Tail Var 90. However, there is no clear trade off between the cost and risk profiles of the Base, Thermal Mix, and No Peaker portfolios.

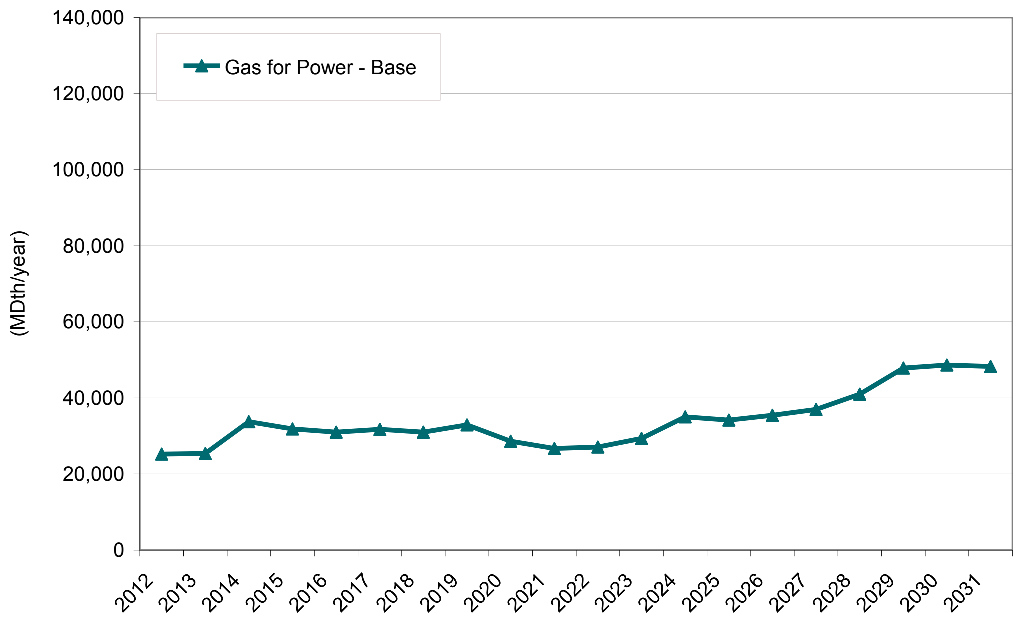
Figure 5-17

Variability and Range of Portfolio Costs in Base Case Scenario



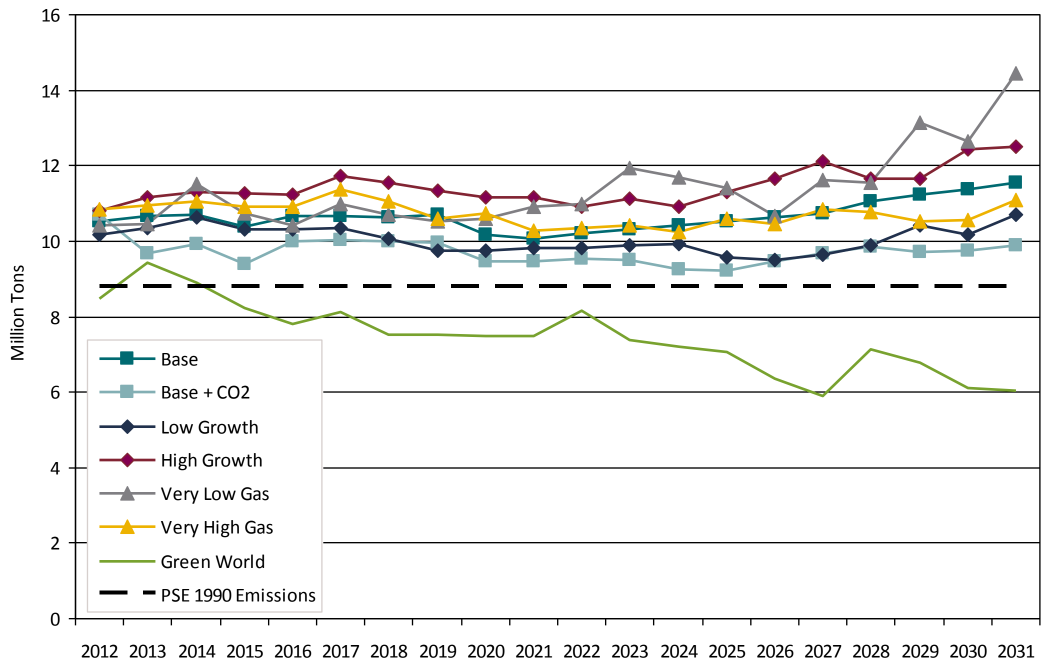
Generation fuel requirements are shown in the following chart. A discussion on how the optimal portfolio affects gas planning can be found in Chapter 6, Gas Analysis.

Figure 5-18
Generation Fuel Requirements



CO_2 emissions for each of the scenarios is shown in Figure 5-19

Figure 5-19
Emissions by Portfolio



5. Key Findings and Insights

The quantitative results produced by this extensive analytical and statistical evaluation led to several key findings that guided the long-term resource strategy presented in this IRP.

1. Portfolio builds are similar across most scenarios.

Resource alternatives are so limited that the portfolio builds for all scenarios look very similar. For all but Green World, the optimal portfolio uses new transmission and peakers to meet physical reliability need, conservation and market power purchases to meet annual energy needs, and wind to meet RPS requirements. Small variations occur due to load variations and "right sizing" (building a small bio-mass unit rather than adding an entire peaker or wind farm, for example), but the similarities are striking.

Green World is the only exception. In this scenario, high gas, CO_2 and market power costs create a situation where wind power is cheaper than market power. Left unconstrained, Green World would have chosen an unlimited amount of wind. Because it is unrealistic for a load-serving utility to take such a speculative position, we constrained the amount of wind allowed to be developed in this scenario.

Figure 5-20
Relative Portfolio Builds and Costs by 2031
Energy in total MW, dollars in billions

	Base	LG	HG	GW	VLG	VHG
Demand-side Resources	1319	1319	1319	1345	1121	1319
Wind	400	300	400	1000	600	300
Biomass	50	50	100	0	0	100
Peaker	2343	1419	3195	1419	2556	2343
New Transmission	500	500	500	500	500	500
Costs	$13.36	$9.83	$18.58	$21.06	$10.87	$16.54

2. Peakers are lower cost than CCCT plants.

Peakers proved to be a lower cost resource alternative than CCCT plants across all planning scenarios. Figure 5-21 below compares the net revenue requirement of peakers and combined-cycle plants across selected scenarios. Net revenue requirements were calculated by taking all capital and fixed costs of a plant and then subtracting the margin (variable costs less market revenue). This calculation lets one quickly compare how these resources are evaluated by the model. PSE also performed a study that burdened the peaking units with the higher-priced, fixed fuel transportation costs that CCCTs are burdened with, but even under these conditions peakers resulted in a lower net cost than CCCTs.

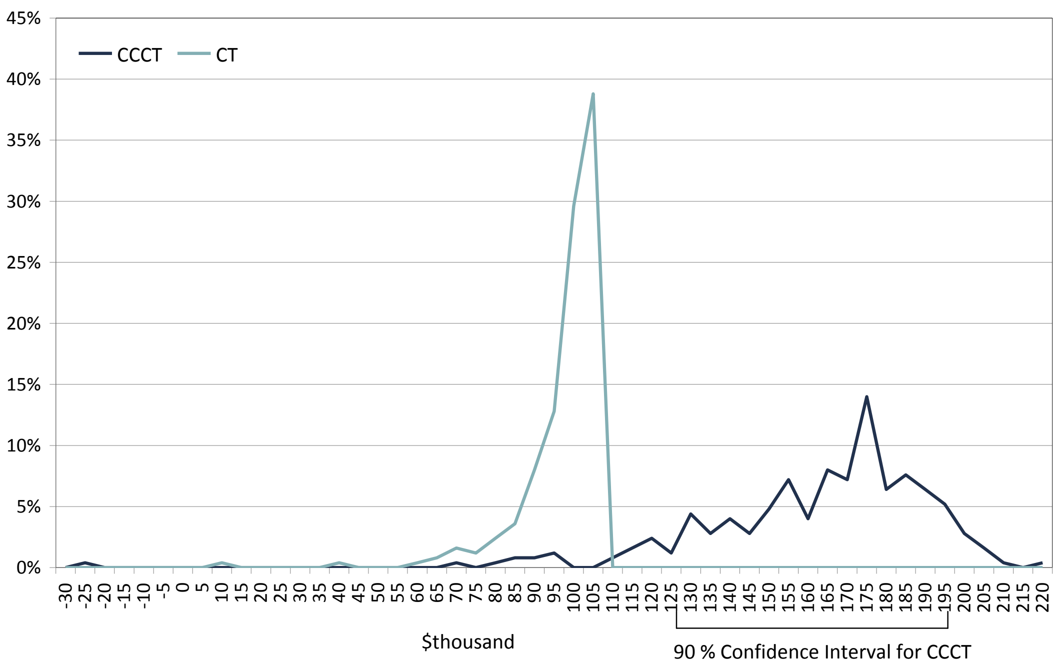
Figure 5-21
Peaker and CCCT Net Thermal Costs Compared

	Base	Base + CO2	Base No Coal	LG	GW
Peaker Rev Requirement (Capital + Fixed)	$242,369	$242,369	$242,369	$242,369	$242,369
Margin	$14,541	$61,876	$83,151	$37,812	$55,266
Net Cost of a Peaker	$227,828	$180,493	$159,218	$204,557	$187,103
$/MW	$1359	$1036	$1136	$1250	$1167

	Base	Base + CO2	Base No Coal	LG	GW
CCCT Rev Requirement (Capital + Fixed)	$812,971	$812,971	$812,971	$812,971	$812,971
Margin	$272,446	$335,292	$325,895	$228,492	$468,812
Net Cost of a CCCT	$540,525	$477,679	$487,076	$584,480	$344,160
$/MW	$1792	$1632	$1604	$1924	$1204

The net cost of a CCCT plant is significantly affected by the margin it generates, and that margin varies as market conditions change. Figure 5-21 illustrates that in the Base Case, the CCCT margin is about one-third of the capital and fixed costs; as market conditions change, so does the margin. Figure 5-22 illustrates the impact of margin on the net cost per MW of a peaker and CCCT plant in the Base Case scenario. This Figure uses a 250-draw Monte Carlo analysis for a single year (2016) to illustrate how the net cost per MW of peakers and CCCT plants are distributed under different market conditions. The cost distribution for peakers is very tight, because peakers do not dispatch or create much margin in many draws. On the other hand, the margin on CCCT plants is widely dispersed, which drives a more wide-spread distribution. That broader CCCT distribution is significantly higher than the distribution on the peaker. The distribution of the peaker lies entirely below the 90% confidence interval for the CCCT plant. This demonstrates that while CCCT plants are expected to operate more and generate margins from those operations, such margins are not expected to be large enough to offset the higher fixed cost of the CCCT.

Figure 5-22 Comparison of Net Cost Distribution: CCCT and Peakers



3. CCCTs do not reduce portfolio risk cost effectively.

Because the all-peaker result differed from past IRP analyses, PSE decided to test whether there were risk reduction benefits to building CCCTs instead, or to building a portfolio that blended CCCTs and peaking units. To do this, we developed two additional sensitivities using the Base Case scenario: The "Thermal Mix" sensitivity forced the optimization model to build enough CCCTs to ensure that the total dollar value of net market power purchases did not exceed 40% of total power cost in any year. The "No

Peakers" sensitivity forced the optimization model to create a lowest-cost portfolio without any peaking plants, with the result that all peakers were replaced with CCCT plants and a minor amount of biomass. Figure 5-23 through 5-26 below show the results of the analysis.

As figure 5-17 shows, adding CCCTs to the portfolio increased costs but did not significantly reduce risk. The two sensitivities observably reduced the portfolio's exposure to market power prices, but at the same time they increased exposure to market gas prices. Adding CCCT generation did not reduce the company's overall exposure.

Figure 5-23 below shows the resource builds by sensitivity. Note that the only measurable differences between the portfolios are the types of gas-fired plants being added. Additionally, the No Peakers sensitivity adds marginally more DSR.

Figure 5-23
CCCT Sensitivities, Builds vs. Base Case Build

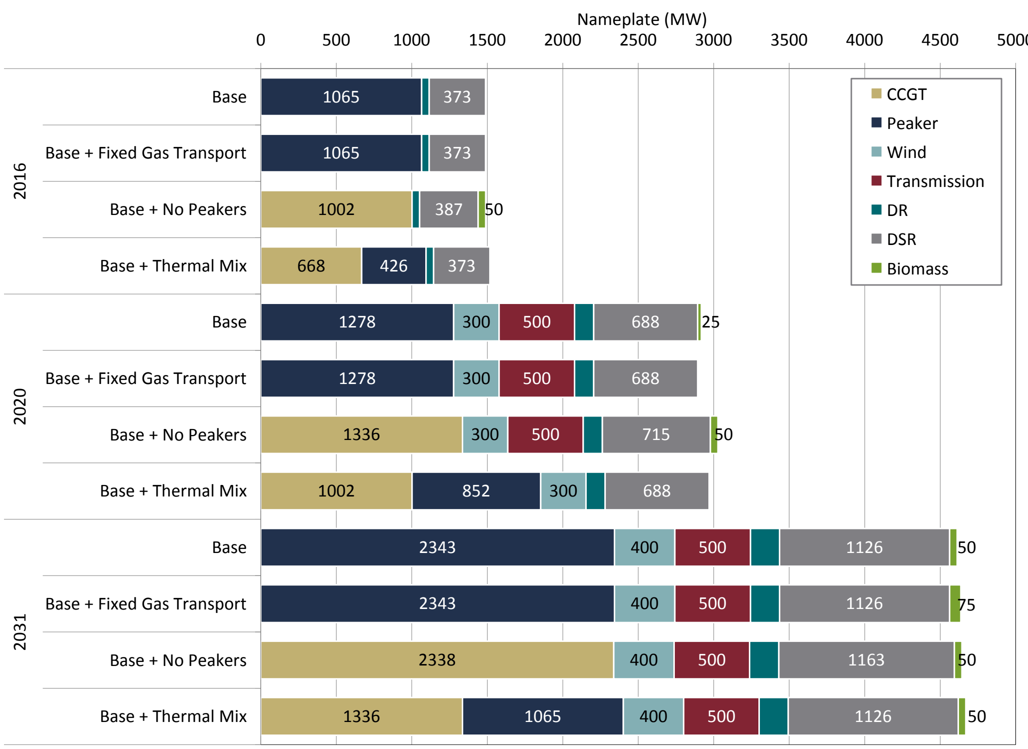


Figure 5-24 shows the costs of the various sensitivities.

Figure 5-24

CCCT Sensitivities, NPV Portfolio Cost Comparisons

Scenario	20-year NPV Expected Cost (Incremental Rev Req $Billiions)
Base	$13.36
Base + Peaker Fixed Gas Transport Cost	$14.10
Base + No Peaker	$14.54
Base + Thermal Mix	$14.26

Figure 5-25

Power Market Exposure

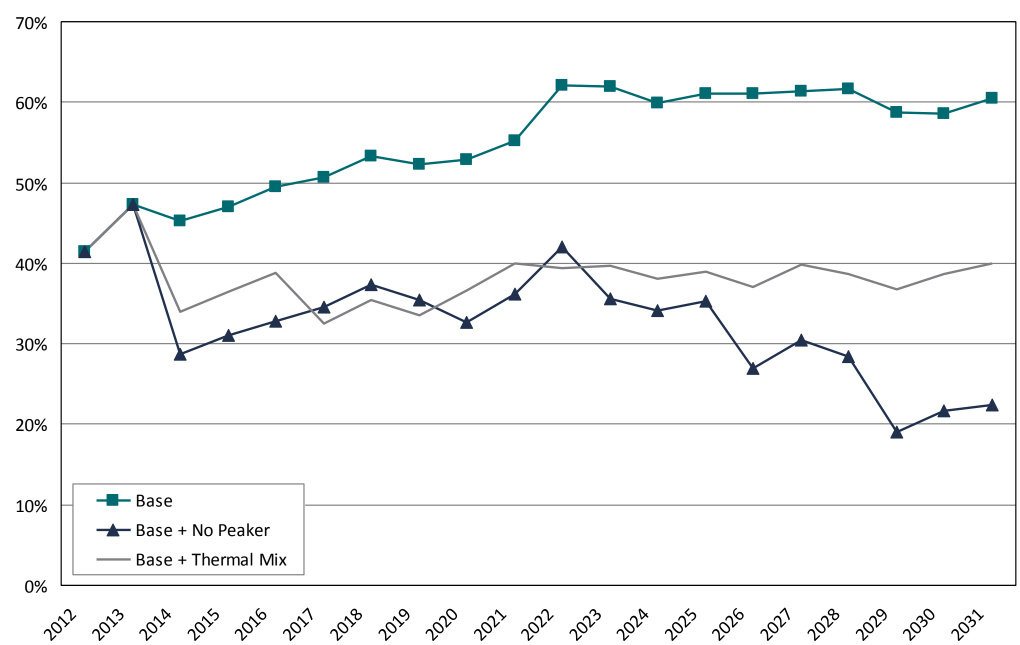
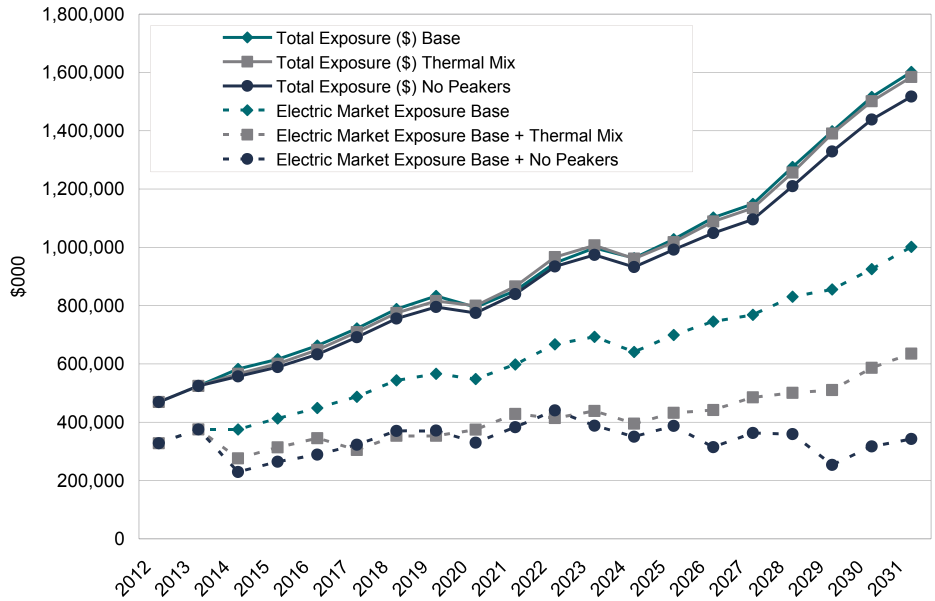


Figure 5-25, above, shows the power market exposure for the different sensitivities. Market exposure is calculated by dividing the dollar amount of net market purchases by the total variable costs of the portfolio. If power market exposure were the only consideration, adding CCCTs to the portfolio would appear to reduce the portfolio's exposure to risk. However, when gas market exposure is considered in addition to power market exposure, adding CCCTs does not reduce risk exposure, as Figure 5-26 illustrates.

Figure 5-26
Total Market Exposure



CCCT plants do reduce variable cost risk relative to peakers but at too high a price to be reasonable. The first part of the table in Figure 5-27 illustrates that the Tail Var 90[3] of variable costs for the portfolio with all CCCT plants instead of peakers is a little over $0.5 billion lower than the Base portfolio with all peakers. The second part of the table illustrates the CCCT portfolio's revenue requirement is $1.18 billion more than the Base Portfolio, which reflects the higher fixed costs of the CCCT plants. This is clearly not a reasonable cost/risk trade-off. The "insurance premium" of the CCCT portfolio costs twice as much as the risk being avoided.

Figure 5-27
Trade Off Table ($Billions) 20-Year NPV

Variable Costs				
	Base Portfolio	Fixed Gas Transport	Peaker/CCCT Blend	No Peaker
Tail Var 90 Variable Costs	$13.15	$13.14	$12.82	$12.60
Relative to Base		-0.01	-0.33	-0.55
Incremental Revenue Requirement[4]				
	Base Portfolio	Fixed Gas Transport	Peaker/CCCT Blend	No Peaker
Expected Incremental Rev Req	$13.36	$14.10	14.26	14.54
Relative to Base		+0.74	+.09	+1.18

[3] *Tail Var 90 is a risk measure, calculated as the mean of the worst 10% of possible outcomes.*
[4] *Incremental Revenue Requirement includes fixed and variable costs for new resources and variable costs for existing resources.*

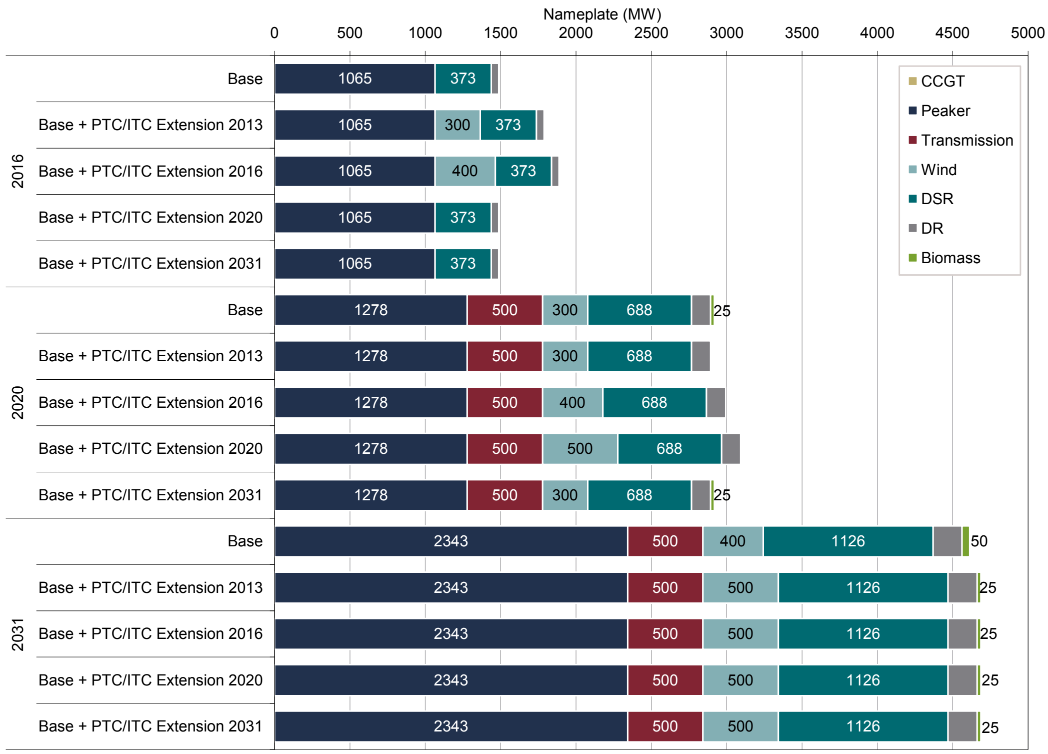
4. RPS requirements drive renewable builds.

The amount of renewable resources included in portfolios is driven by RPS requirements. Figures 5-28 and 5-29 show results of portfolio comparisons performed to test how changes in CO_2 costs, load growth, demand-side resources, and financial incentives such as the cash grant or production tax credit (PTC) extensions, would affect wind additions to the portfolios. As explained in Chapter 4, this analysis assumed treasury grants were the financial incentive being used. Green World is the only scenario that increases wind more than required by the RPS.

Figure 5-28
The Effect of Variables on Wind Additions in 2029

Variable	Portfolio's to Compare	Effects of Change
CO_2 Cost Changes	Base Case Base + CO_2	The Base Case builds 400 MW of wind and 50 MW of biomass. Increased CO_2 costs in Base +CO_2 resulted in 500 MW of wind and no biomass.
Load Changes	Low Growth Base High Growth	At the low end of the spectrum, Low Growth adds 300 MW of wind and 50 MW of biomass. At the high end, High Growth adds 400 MW of wind and 100 MW of biomass.
DSR Changes	Base No DSR vs. Base	Adding the optimal amount of DSR in the Base Case reduced the amount of wind built.
Financial Incentive Changes	Financial Incentive extensions	Renewable additions coincide with the expiration of financial incentives. Extending the incentives farther out into the future results in similar pushing renewables into the future.

Figure 5-29
Financial Incentive Extension Comparison



The chart above shows how portfolios are optimized using different assumptions for financial incentive extensions. In the Base Case, PSE assumes no extension of financial incentives and that all wind additions coincide with filling REC need. The other portfolios extend financial incentives until 2013, 2016, 2020, and 2031. With the exception of the 2031 portfolio (which assumes such incentives are available during the entire planning period), renewable additions are accelerated to take advantage of the expiring incentives.

5. Limiting emissions will be difficult.

PSE examined how different carbon mitigation strategies will affect portfolio builds, costs, and emissions. Figure 5-30 illustrates that only two of the three carbon mitigation strategies modeled achieve emissions below 1990 levels – Green World and No Northwest Coal. However, both would lead to significant future costs; Figure 5-31 shows the annual revenue requirements for these portfolios. By 2021, No Northwest Coal increases the company's revenue requirement by about $196 million over the Base Case; Green World increases the revenue requirement by about $ 787 million. While both strategies achieve 1990 emissions levels, the costs are considerable.

It is important to consider the limitations of this analysis when considering the scenario in which all Northwest coal plants are forced to retire, as PSE used some simplifying assumptions to complete the IRP analysis in a timely manner. In reality, as these resources are forced to expire the region will be required to build additional CCCT plants to replace the lost energy and capacity of the coal plants. In the IRP analysis, Aurora assumed that "the region" would build them; then the optimization model took advantage of their "existence" and so did not recommend adding CCCT to PSE's portfolio. If the region were to retire all coal plants, PSE's options may indeed include the economic development of these plants. This highlights a need for the company to investigate updating our analytical frameworks to better address issues that may arise if regional coal plants are put out of service. .

Figure 5-30

Annual Emission Rates for Base, Base + CO2, No NW Coal and Green World Portfolios

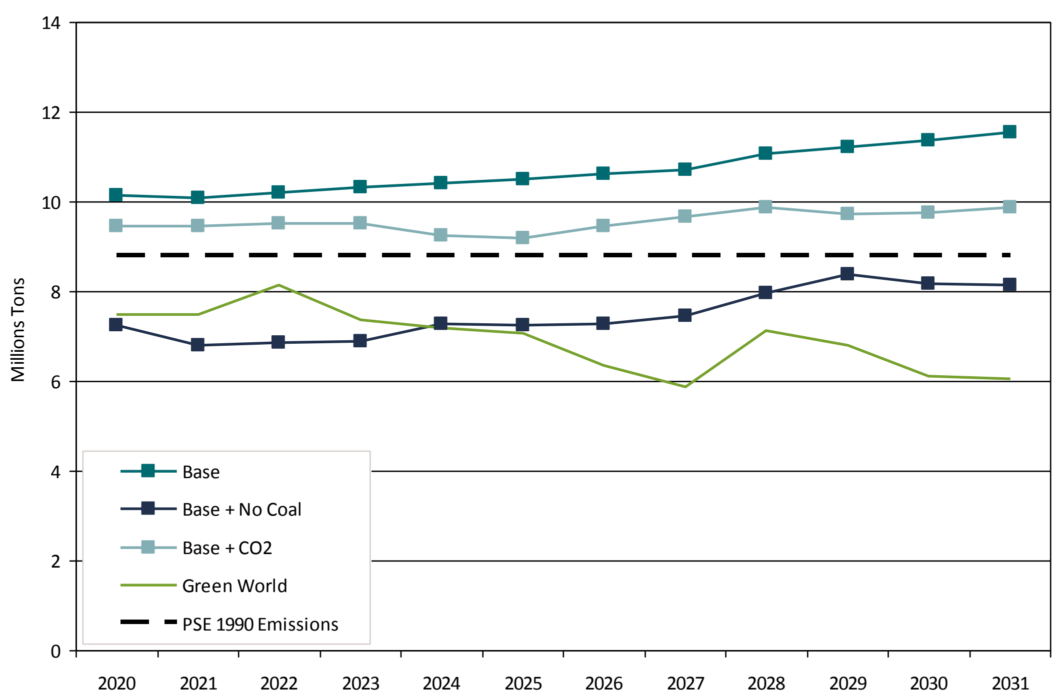
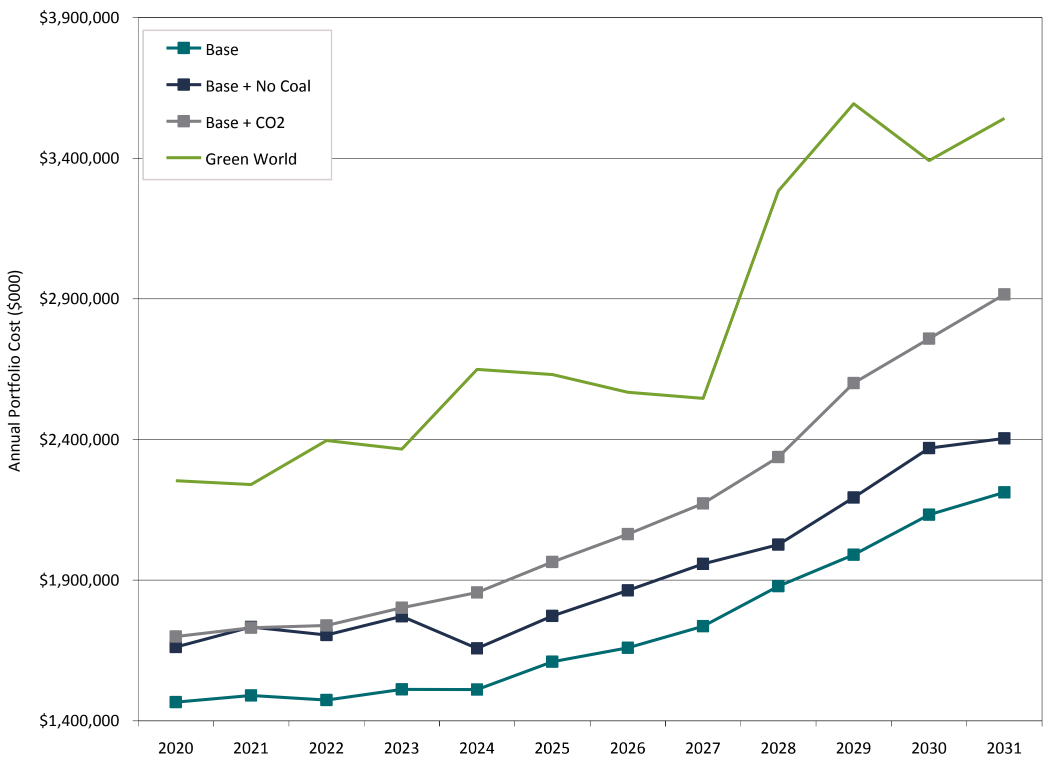


Figure 5-31
Annual Revenue Requirements for Base, Base + CO_2, No NW Coal, and Green World Portfolios



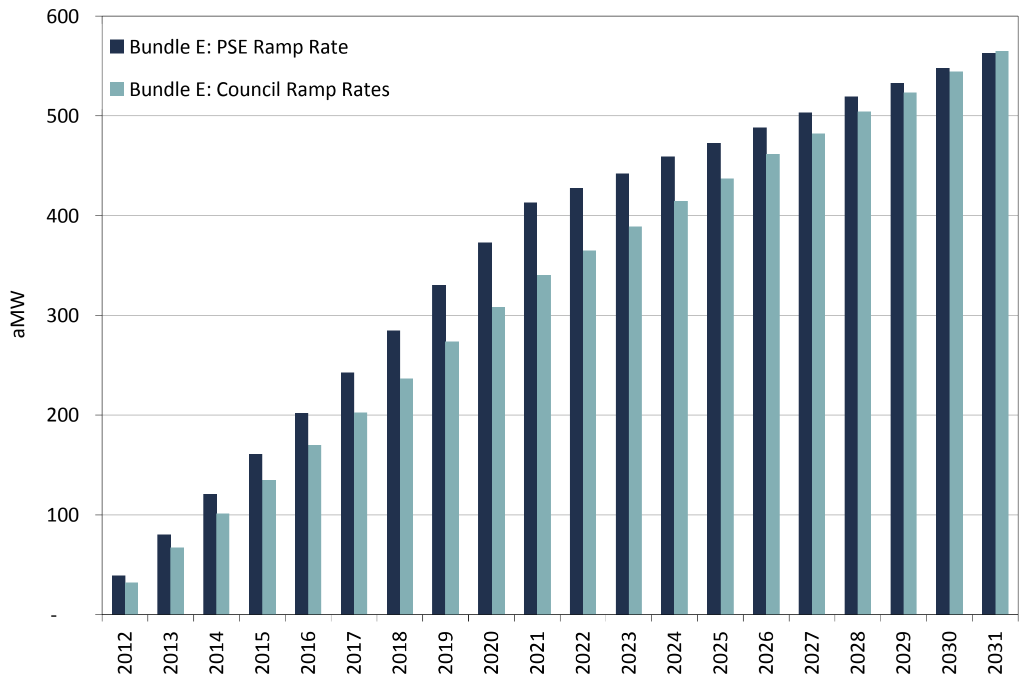
6. DSR is the only resource that reduces cost and risk – and the sooner it's acquired, the more cost-effective it is.

Demand-side resources are the only resources that reduce both cost and risk in portfolios. The amount of cost-effective conservation acquired is the same in all but one scenario (Green World). At minimum, all other scenarios identified DSR Bundle E to be cost effective. The cost-effective level of DSR remained fairly constant even though "avoided market costs" varied. We also found that a more rapid ramp rate for DSR improved the cost-effectiveness of these measures.

PSE's plan applies a 10-year ramp rate for DSR that is more aggressive than the rate applied in the NPCC's 6th Power Plan for similar measures. To compare the two, Cadmus developed a detailed, measure-by-measure assessment of the NPCC's ramp rates based on the customer mix and appliance/measure saturation for PSE's service territory.[5] Figure 5-33 uses Bundle E to compare the two. PSE's 10-year ramp rate acquires DSR more quickly than the NPCC's ramp rate, though by the end of the planning horizon the total amounts are the same.

Figure 5-33

DSR Sensitivity: NPCC's Ramp Rates from the 6th Power Plan applied to PSE's service territory



[5] *Note this was a more in-depth analysis than the NPCC's "calculator" which allocates conservation potential based on kWh sales.*

This IRP analysis also tested whether acquiring DSR more or less quickly affected the cost effectiveness of the measures. To test this, we first used portfolio optimization analysis to find the least-cost combination of demand-side and supply-side resources in the Base Case scenario. Then we applied the NPCC's ramp rate in one analysis and PSE's 10-year ramp rate in another. Figure 5-34 summarizes the result. Bundle E with the more aggressive, 10-year ramp rate proved more cost effective.

Figure 5-34
PSE's 10-year ramp rate is more cost effective than the ramp rate from the 6th Power Plan

Base Scenario	20-yr Expected Incr Rev Req ($Billions)	Bundle	DR
Base (PSE Ramp)	$13.36	E	Yes
Base + 6th Power Plan Ramp	$13.53	E	Yes

Demand-side resources are the only resources that reduce both cost and risk in portfolios. They must be cost effective to be included in the plan, so by definition they are also least cost resources. Figure 5-35 shows the expected power costs and risk ranges for a No DSR portfolio and the optimal Base Case portfolio, which includes 1,319 MW of DSR by 2031. Figure 5-36 compares their expected costs and cost ranges.

The amount of cost-effective conservation acquired is the same in all but one scenario. At a minimum, all scenarios identified DSR Bundle E to be cost effective; other bundles became cost effective only in Green World. Figure 5-37 shows the selected DSR bundle and the associated avoided market costs by scenario. It is interesting to note that the cost-effective level of DSR remains fairly constant even though "avoided market costs" vary. A full description of the bundles and the associated measures in each bundle can be found in Appendix K, Demand-side Resource Analysis.

Figure 5-35
Effect of DSR on Costs and Risk

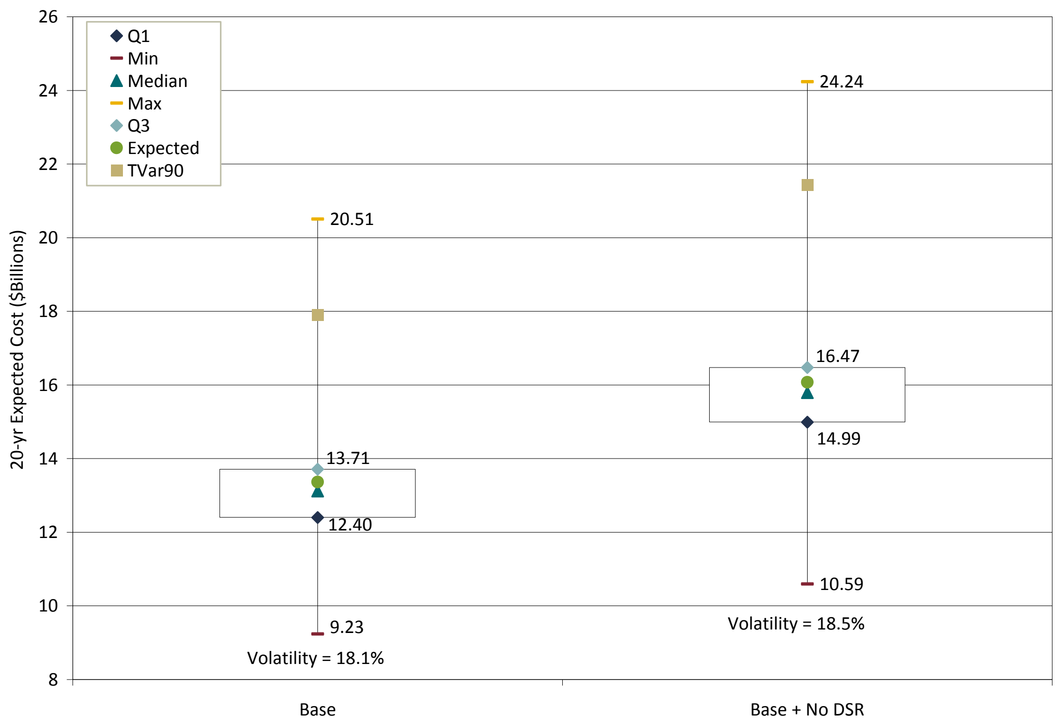


Figure 5-36
Comparison of Expected Costs and Cost Ranges for No-DSR and Base Case Portfolios
20-yr NPV Portfolio Cost (dollars in billions)

	Base	Base + No DSR	Difference
Expected Cost	13.36	16.07	2.71
TVar90	17.90	21.43	3.53

DSR reduces power cost risk relative to No DSR. Figure 5-36 illustrates that the Tail Var 90 of variable costs for the portfolio with No DSR would be a little over $3.53 billion higher than the Base portfolio with DSR. Figure 5-36 illustrates that the No DSR portfolio revenue requirement is $2.71 billion more than the Base Portfolio, which reflects the higher costs of adding peakers instead of DSR. This is clearly a reasonable cost/risk trade-off. Adding DSR to the portfolio reduces cost and significantly reduces risk at the same time.

Figure 5-37
Optimal DSR Bundles and Avoided Market Costs by Scenario

Scenarios	20-year Levelized Net Market Value	DSR Bundle
Base	$62.78	E
Base + CO2	$78.21	E
Low Growth	$49.35	E
High Growth	$90.94	E
Very Low Gas Prices	$45.48	B
Very High Gas Prices	$91.34	E
Green World	$127.57	G