Electric Analysis

This appendix presents details of the methods and models employed in PSE's electric resource analysis, and the data produced by that analysis.

1. Methods and Models

i. Overview

ii. Development of Monte Carlo Simulations for the Risk Variables

iii. Aurora for Dispatch of PSE Portfolio

iv. Portfolio Screening Model

2. Data

I. Key Inputs and Assumptions, I-14

A. Aurora Inputs

B. Production Tax Credit and Renewable Portfolio Standard

i. Production Tax Credit Assumptions

ii. Investment Tax Credit Assumptions

iii. Renewable Portfolio Standard

C. Generic Resource Costs and Characteristics

D. Generic Resource Capital Costs Escalation Profiles

E. Wind Capacity Credit

F. Diagram of Transmission Zones

G. Planning Standards

II. Output, I-25

A. Avoided Costs/Aurora Electric Prices

B. Electric Demand-side Screening Results

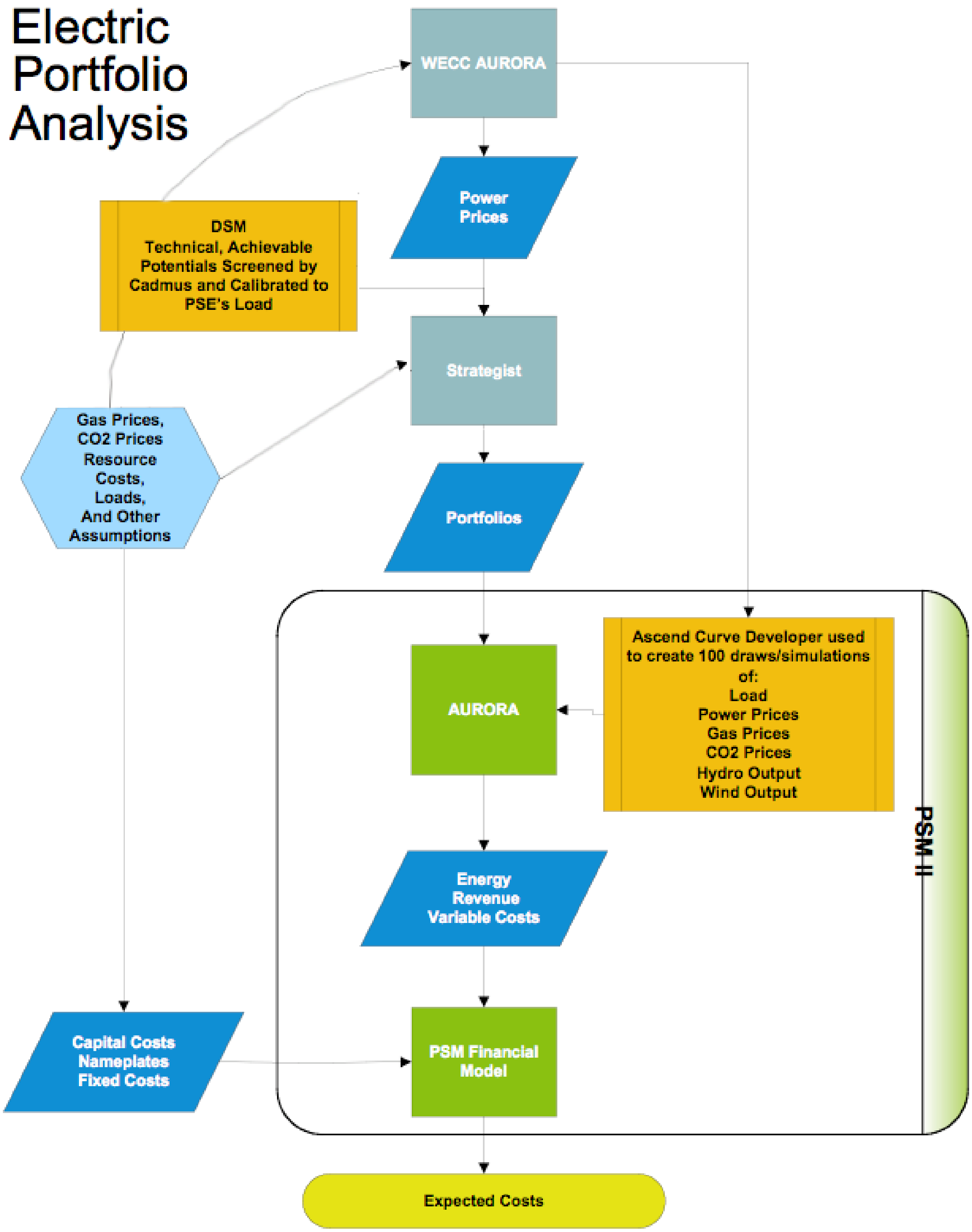
C. Electric Integrated Portfolio Results

1. Methods and Models

I. Methods

A. Diagram of Process for 2009 IRP

PSE uses three models for integrated resource planning: AURORAxmp, Strategist and the Portfolio Screening Model II (PSM II). AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions, as described in Chapter 3. Strategist creates optimal long-term electric supply and demand portfolios for each of the potential futures as described in Chapter 3. PSM II tests these portfolios to evaluate PSE’s long-term revenue requirements for the incremental portfolio and risk of each portfolio. The following diagram shows the methods used to quantitatively evaluate the lowest reasonable cost portfolio.


Electric
Portfolio
Analysis
WECC AURORA
Power
Prices
DSM
Technical, Achievable
Potentials Screened by
Cadmus and Calibrated to
PSE's Load
Strategist
Gas Prices,
CO2 Prices
Resource
Costs,
Loads,
And Other
Assumptions
Portfolios
Ascend Curve Developer used
to create 100 draws/simulations
of:
Load
Power Prices
Gas Prices
CO2 Prices
Hydro Output
Wind Output
AURORA
PSM II
Energy
Revenue
Variable Costs
Capital Costs
Nameplates
Fixed Costs
PSM Financial
Model
Expected Costs

B. Risk Analysis

i. Scenarios

A description of the nine scenarios can be found in Chapter 3, section 1, *Electric Analysis Components*. The monthly price output from these scenarios can be found in section 2 of this appendix.

ii. Portfolios

An optimal portfolio was found for each scenario and sensitivity described in Chapter 3 for a total of 16 portfolios. The optimal portfolio for each scenario is the lowest cost combination of supply and demand side resources that meets our needs. More details on these portfolios can be found in section 2 of this appendix. Two additional portfolios were created as extreme situations, one all peaker and one all base load CCCT portfolios.

iii. Probabilistic Analysis of Risk Factors

In addition to using scenarios to assess risk, this 2009 IRP continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling in AURORAxmp. It relies on Monte Carlo simulations of six uncertainty factors: market prices for natural gas, market prices for power, CO2 prices, weather variability for load, wind generation variability, and hydroelectric generation availability. The simulations are based on assumptions about correlations and volatilities between the risk variables and also across time, based on the Ascend Analytics Curve Developer model. This model and its assumptions are further described later in this appendix.

iv. Risk Measures

The results of the Monte Carlo simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10% of outcomes (called TailVar90). This risk measure is the same as the risk measure used by NWPCC in its Fifth Power Plan. Additionally, we looked at annual volatility by measuring year to year changes in revenue requirements. Then we calculated the standard deviation of those year to year changes. The final measure of volatility is the average of the standard deviation across the simulations. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed cost recovery for existing assets.

II. Models

A. The AURORA Dispatch Model

i. Overview

PSE uses the AURORA model to estimate the market price of power used to serve our core customer load. The model is described below in general terms to explain how it operates, with further discussion of significant inputs and assumptions.

The following text was provided by EPIS, Inc. and edited by PSE.

> AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources, regional demand for power, and transmission, which drive the electric energy market. AURORA models the competitive electric market, using the following modeling logic and approach to simulate the markets: prices are determined from the clearing price of marginal resources. Marginal resources are determined by “dispatching” all of the resources in the system to meet loads in a least cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.
>
> AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum-run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

ii. Long Run Optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, unless reserve margin targets are selected; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

iii. Use of Reserve Margin Targets

During the summer of 2006, EPIS, Inc. released a new version of AURORAxmp, along with an input database that included the necessary inputs to perform long-term studies using planning reserve margin targets. The model builds resources to meet target reserve margins and estimates the "capacity price payments necessary to support the marginal entrants supplying capacity to the system."[1]

PSE uses reserve margin targets at the pool level, which consists of the Northwest Power Pool territory. The overall pool reserve margin target is 15%. PSE tested capacity pool reserve margins at 0%, 5%, and 15%. A pool reserve margin of 15% best mitigated summer price spreads without increasing average prices unreasonably. Many U.S. regions plan for at least a 15% reserve margin.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

[1] EPIS, Inc., "Long-Term Studies Using Reserve Margins," from AURORAxmp electronic documentation, December 2005.

B. Strategist

The following text was provided by Ventyx:

i. Overview

Strategist, a computer software system developed by Ventyx, supports electric utility decision analysis and corporate strategic planning. The system combines quality planning software, a proven track record, Ventyx's commitment to ongoing maintenance and support, comprehensive user documentation (online help), and fast response to client needs. Strategist is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist consists of the following application modules:

- Load Forecast Adjustment (LFA)
- Generation and Fuel (GAF)
- PROVIEW (PRV)
- Capital Expenditure and Recovery (CER)
- Differential Cost Effectiveness COST (DCE)
- Dynamic Marketing Program Design (DPD)
- Financial Reporting and Analysis (FIR)
- Class Revenue (CRM)
- Holding Company (HCM)

ii. General Description

Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. Financial analyses are accurate and thorough. Rate-level determinations reflect each utility's customer class definition and cost-of-service allocation factors. The system employs dynamic programming to develop optimal portfolios of resources. Sophisticated screening methodologies are available to develop and refine strategic marketing initiatives, identify market potential, and build portfolios of initiatives. In Strategist, integrated resource screening and optimization is accomplished within a single system that handles strategic marketing programs, production costing, environmental reporting, capital budgeting and financial, tax, and revenue forecasts on a rate class basis. Using a single, integrated software system for demand- and supply-side analysis of all resource types makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results. With Strategist, utility management can examine many more options in a shorter period of time. The system has been designed to streamline the many steps in a comprehensive integrated planning effort and to handle the mechanics. This minimizes human error, inconsistencies, and repetitive data entry. For instance, if a combustion turbine's in-service date is delayed in the optimization program, the new in-service date is automatically specified to the production costing module as well as the capital budgeting and financial modules. The module also performs year-by-year "round robin" processing in order to appropriately address price elasticity. Strategist provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics.

C. Portfolio Screening Model II – Risk Analysis Model

i. Overview

The new risk model used for this IRP combines the strengths of the short term risk model (Ascend Analytic's Curve Developer) in generating the Monte Carlo draws for the risk variables with the dispatch algorithm in AuroraXMP, plus the financial modeling detail of the portfolio screening model. Given each draw from the Curve Developer, Aurora model generates the variable costs of dispatched generation from a given PSE portfolio that includes existing/new resources and market purchases/sales. These outputs are then used as inputs into the Portfolio Screening Model which combines other data to generate the revenue requirements. Below is a description of the various models. The Figure below shows the major components of this new risk model.

ii. Development of Monte Carlo Draws for the Risk Variables

PSE utilized Ascend Analytic's Curve Developer to develop the draws for the risk variables. The heart of the simulation engine is a Monte Carlo simulation of physical elements and market prices. This engine produces Monte Carlo simulations of weather, load, market prices, and hydropower and wind generation through a state-space modeling approach.

State-space modeling in its simplest form is regression analysis with uncertainty. The uncertainty associated with regression analysis can be used to explain how weather relates to load, or yesterday's forward price relates to today's forward price. Simple regression analysis seeks to maximize the predictive capabilities of the explanatory variables on the dependent variable.

The regression line provides the best fit between the individual explanatory values and maximizes the predictive value of each explanatory variable to the dependent variable. However, there exist several components of uncertainty in a regression equation, including: i) uncertainty in the coefficient estimate, ii) uncertainty in the residual error term, and iii) the covariate relationship between the uncertainty in the coefficients and the residual error. State-space modeling captures these elements of uncertainty.

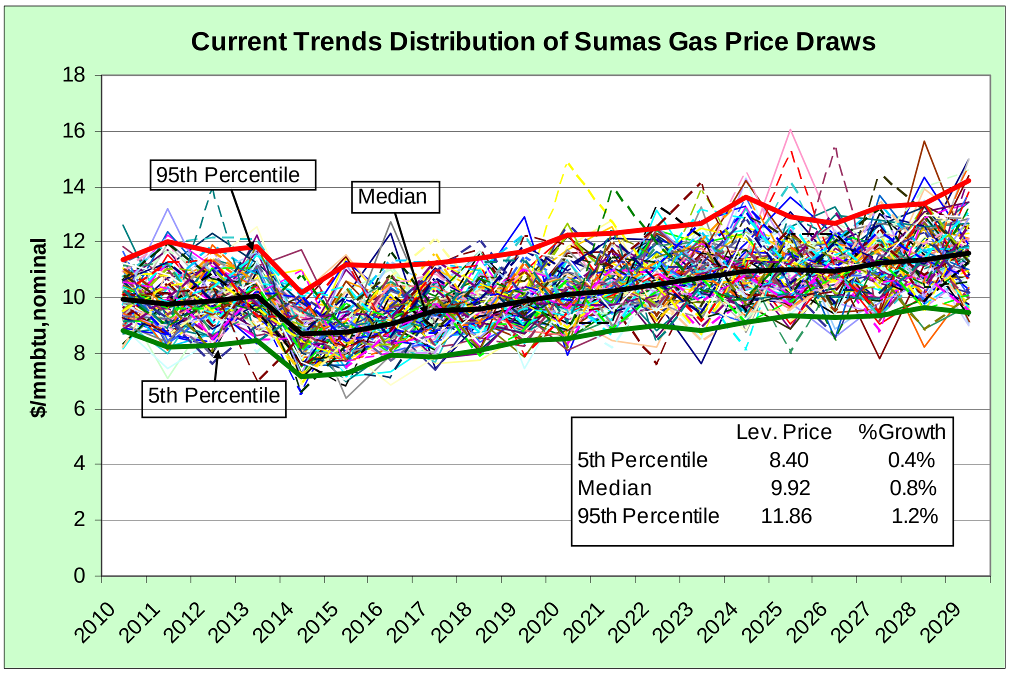
By preserving the covariate relationships between the coefficients and the residual error, we are able to maintain the relationship of the original data structure as we propagate results through time. For a system of equations, correlation effects between equations are captured through the residual error term.

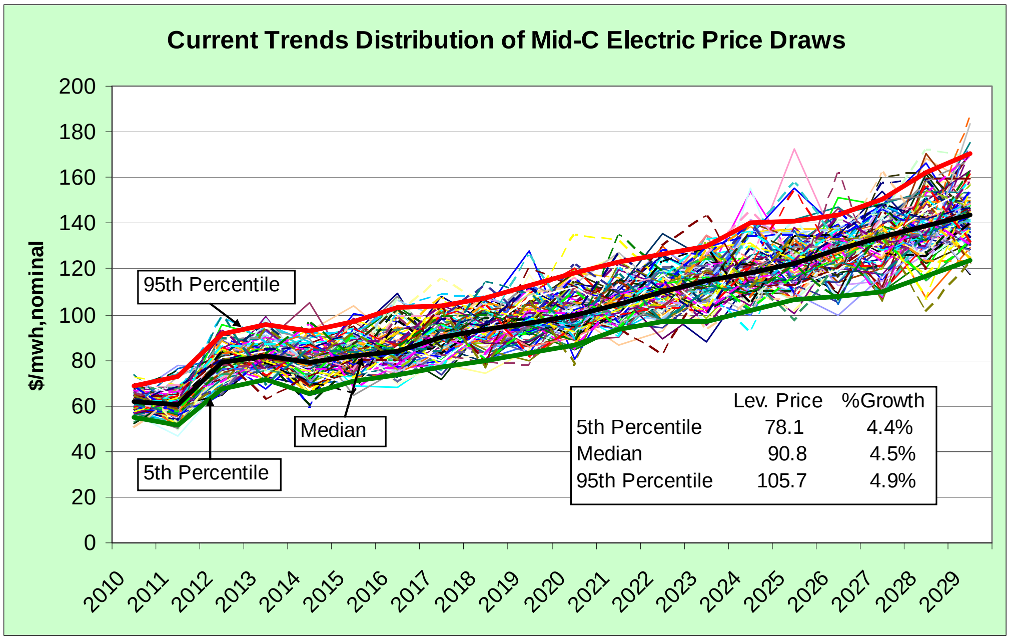
The logic of the linked physical and market relationships needs to be supported with solid benchmark results demonstrating the statistical match of the input values to the simulated data.

It is important to compare this approach with what was done in previous IRPs. Previous IRPs have only assumed a distribution of the risk variables with a given correlation between electric and gas prices. There were no linked relationships between weather and load or hydro/wind generation, for example. Draws were made independent of the links, hence, it was possible to obtain results which were less realistic.

This approach is used to generate 100 simulations of the following risk variables: PSE's load forecasts which depend on temperatures, hydroelectric generation for Mid Columbia projects and PSE-owned hydroelectric projects in Western Washington, wind outputs from Wild Horse and Hopkins Ridge, Mid Columbia electric prices, Sumas gas prices, and CO2 emission prices. The correlation between electric and gas prices is assumed to be 0.85.

Examples of the simulation of Sumas gas prices and Mid Columbia electric prices for Current Trends scenario are shown in the two charts below. The chart shows the 100 draws, median, 5th and 95th percentiles over time, including a comparison of their levels and growth rates.




Current Trends Distribution of Mid-C Electric Price Draws
$/mwh,nominal
200
180
160
140
120
100
80
60
40
20
0
95th Percentile
Median
5th Percentile
Lev. Price
%Growth
5th Percentile
78.1
4.4%
Median
90.8
4.5%
95th Percentile
105.7
4.9%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029

iii. Aurora Risk Modeling of PSE Portfolios

The advanced risk modeling capabilities of Aurora are utilized to generate the variable costs of any given portfolio. The main advantage of using Aurora is its fast hourly dispatch algorithm for 20 years that is already well known by the majority of Northwest utilities. It also calculates market sales and purchases automatically, and produces other reports such as fuel usage and generation by plant for any time slice. Instead of defining the distributions of the risk variables, however, the set of 100 draws for all of the risk variables (power prices, gas prices, CO2 prices, PSE loads, hydroelectric generation and wind generation) are fed into the model. Given each of these input draws, Aurora then dispatches a given PSE portfolio to market price and computes the implied market sales and purchases each hour. The results of each draw are then saved and passed on to the portfolio screening model, where expected revenue requirements and risk metrics are computed. Expected costs and risk metrics can then be computed for each set of portfolio generated by Strategist.

iv. Portfolio Screening Model

The Portfolio Screening Model (PSM) is a Microsoft Excel-based revenue requirement model the company developed to evaluate incremental cost and risk for a wide variety of resource alternatives and portfolio strategies. The PSM calculates the incremental portfolio costs of resources required to serve load. Incremental cost includes: (i) the variable fuel cost and emissions for PSE’s existing fleet, (ii) the variable cost of fuel emissions and operations and maintenance for new resources, (iii) the fixed depreciation and capital cost of investments in new resources, (iv) the book cost and offsetting market benefit remaining at the end of the 20-year model horizon, and (v) the market purchases or sales in hours when resources are deficient or surplus to PSE’s need.

PSM is a modeling tool that can

(i) quickly evaluate and compare results for a wide range and large number of alternative resource strategies;

(ii) calculate variable costs for all resources, including existing and new resources, as well as fixed costs for new resources (AURORA does not address fixed costs for new resources added to a utility’s portfolio).

The primary input assumptions to the PSM are

(i) PSE's existing portfolio,

(ii) variable cost, total energy and revenue from AURORAxmp,

(iii) costs of generic resources,

(iv) financial assumptions such as cost of capital and escalation rates,

(v) a generic resource mix.

2. Data

I. Key Inputs and Assumptions

A. Aurora Inputs

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. In reality, the continental United States is divided into three regions, and electricity is not traded between these regions. The western-most region, called the Western Electricity Coordinating Council (WECC), includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado, and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy is traded and transported to and from these foreign areas, but is not traded with Texas, for example.

For modeling purposes, the WECC is divided into 30 areas primarily by state and province, except for California which has eight areas, Nevada which has two areas, and Oregon and Washington which are combined. These areas approximate the actual economic areas in terms of market activity and transmission. The databases are organized by these areas and the economics of each area is determined uniquely.

Load forecasts are created for each area. These forecasts include the base year load forecast and an annual average growth rate. Since the demand for electricity changes over the year and during the day, monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: for example, the monthly load shape would show that California has a summer peak demand and the Northwest has a winter peak. For the 2009 IRP, load forecasts for Oregon, Washington, Montana and Idaho were based on the Pacific Northwest Utilities Conference Committee's (PNUCC) 2007 Northwest Regional Forecasts. All generating resources are included in the resource database, along with characteristics of each resource, such as its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). The resource database assumptions are based on EPIS's 2008-1 version produced in February 2008.

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically an RPS states that a specific percentage of energy consumed must be from renewable resources by a certain date (e.g., 10% by 2015). While these states have demonstrated clear intent for policy to support renewable energy development, they also provide pathways to avoid such strict requirements. Further details of these assumptions are discussed in Section B below.

Coal prices were adopted from Global Insight's winter 2007-2008 US Energy Outlook price forecasts.

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydropower generation is based on the average stream flows for the 50 historical years of 1929 to 1978. While there is also much hydropower produced in California and the Southwest (e.g., Hoover Dam), it does not drive the prices in those areas as it does in the Northwest. In those areas, the normal expected rainfall and hence, the average power production is assumed for the model. For sensitivity analysis, PSE can vary the hydropower availability, or combine a past year's water flow to a future year's needs.

Electric power is transported between areas on high voltage transmission lines. When the price in one area is higher than it is in another, electricity will flow from the low priced market to the high priced market (up to the maximum capacity of the transmission system), which will move the prices closer together. The model takes into account two important factors that contribute to the price: first, there is a cost to transport energy from one area to another, which limits how much energy is moved; and second, there are physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas. EPIS updates the model to include known upgrades (e.g., Path 15 in California) but the model does not add new transmission "as needed."

B. Production Tax Credit and Renewable Portfolio Standard

i. Production Tax Credit Assumptions

The Production Tax Credit (PTC) is one of many federal subsidies related to production of nuclear, oil, gas and alternative energy. The present PTC amounts to approximately $21 (in 2010 dollars) per MWh for ten years of production, and is indexed for inflation. As of September 2008, the PTC was scheduled to expire at the end of 2009. The reference assumption is that PTCs remain at the current rate through 2013. PTCs are still assumed to be given to a project for 10 years after it is placed into service. As of 2014, this reference assumes no further PTCs are available to new resource development.

ii. Investment Tax Credit Assumptions

The Investment Tax Credit (ITC) is one of many federal subsidies related to production of renewable energy. The present ITC amounts to approximately 30% of the capital cost for solar resources and 10% of the capital cost for biomass and geothermal resources. Currently the ITC is scheduled to expire at the end of 2016. This scenario assumes ITCs remain at the current rate through 2016, then drop to 10% for solar and remain the same for biomass and geothermal for the remainder of the time horizon.

iii. Renewable Portfolio Standard

Renewable portfolio standards (RPSs) exist in 29 states and the District of Columbia, including most of the states in the WECC. Each state defines renewable energy sources differently, has different timetables for implementation, and has different requirements for the percentage of load that must be supplied by renewable resources. To model these varying laws, we first identified the load forecast for each state in the model. Then we identified the benchmarks of each RPS (e.g. 3% in 2015, then 15% in 2020) and applied them to the load forecast for that state. No retirement of existing WECC renewable resources was provided for, which perhaps underestimates the number of new resources that need to be constructed. After existing and expected renewable energy resources were accounted for, new renewable energy resources were matched to the load to meet the RPS. With internal and external review for reasonableness, these resources are created in the AURORA database. The renewable energy technologies included wind, solar, biomass and geothermal. Estimates of potential production by states in the "Renewable Energy Atlas of the West" served to guide the creation of RPS resources. These vary considerably. For example, Arizona has little wind potential but great solar potential. For this IRP, RPS targets were updated for Oregon, California, Colorado, New Mexico and British Columbia.

The Table below includes a brief overview of the RPS for each state in the WECC that has one. The “Standard” column offers a summary of the law, as provided by the Lawrence Berkeley National Laboratory (LBNL), and the “Notes for AURORA Modeling” column includes a description of the new renewable resources created to meet the law.

State	Standard (LBNL)	Notes for AURORA Modeling
Arizona	New Proposed RPS: 1.25% in 2006, increasing by 0.25% each year to 2% in 2009, then increasing by 0.5% a year to 5% in 2015, and increasing 1% a year to 14% in 2024, and 15% thereafter. Of that, 5% must come from distributed renewables in 2006, increasing by 5% each year to 30% by 2011 and thereafter. Half of distributed solar requirement must be from residential application; the other half from non-residential non-utility applications. No more than 10% can come from RECs, derived from non-utility generators that sell wholesale power to a utility.	Very little potential wind generation is available. Most of the requirement is met with central solar plants. The distributed solar (30%) is accounted for by assuming central renewable energy.
British Columbia	Clean renewable energy sources will continue to account for at least 90% of generation. 50% of new resource needs through 2020 will be met by conservation.	The assumption is that a majority of this need will be met by hydropower and wind.
California	IOUs must increase their renewable supplies by at least 1% per year starting January 1, 2003, until renewables make up 20% of their supply portfolios. The target now is to meet 20% level by 2010, with potential goal of 33% by 2020. IOUs do not need to make annual RPS purchases until they are creditworthy. CPUC can order transmission additions for meeting RPS under certain conditions.	The California Energy Commission created an outline of the necessary new resources by technology that could meet the 20% by 2010 goal. Technologies include wind, biomass, solar and geothermal in different areas of the state The renewable energy resources identified in the outline were incorporated into the model.
Colorado	HB 1281 -Expands the definition of "qualifying retail utility" to include providers of retail electric services, other than municipally owned utilities, that serve 40,000 customers or less. Raises the renewable energy standard for electrical generation by qualifying retail utilities other than cooperative electric associations and municipally owned utilities that serve more than 40,000 customers to 5% by 2008, 10% by 2011, 15% by 2015, and 20% by 2020. Establishes a renewable energy standard	The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only.

	for cooperative electric associations and municipally owned utilities that serve more than 40,000 customers of 1% by 2008, 3% by 2011, 6% by 2015, and 10% by 2020. Defines "eligible energy resources" to include recycled energy and renewable energy resources.	
Montana	5% of sales (net of line losses) to retail customers in 2008 and 2009; 10% from 2010 to 2014; and 15% in 2015 and thereafter. At least 50 MW must come from community renewable energy projects during 2010 to 2014, increasing to 75 MW from 2015 onward. Utilities are to conduct RFPs for renewable energy or RECs and after contracts of at least 10 years in length, unless the utility can prove to the PSC the shorter-term contracts will provide lower RPS compliance costs over the long-term. Preference is to be given to projects that offer in-state employees or wages.	The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW.
Nevada	6% in 2005 and 2006 and increasing to 9% by 2007 and 2008, 12% by 2009 and 2010, 15% by 2011 and 2012, 18% by 2013 and 2012, ending at 20% in 2015 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane) and not more than 25% of the required standard can be based on energy efficiency measures.	The Renewable Energy Atlas shows that considerable geothermal energy and solar energy potential exists. For modeling the resources are located in the northern and southern part of the state respectively, with the remainder made up with wind.
New Mexico	Senate Bill 418 was signed into law in March 2007 and added new requirements to the state's Renewable Portfolio Standard, which formerly required utilities to get 10% of their electricity needs by 2011 from renewables. Under the new law, regulated electric utilities must have renewables meet 15% of their electricity needs by 2015 and 20% by 2020. Rural electric cooperatives must have renewable energy for 5$ of their electricity needs by 2015, increasing to 10% by 2020. Renewable energy can come from new hydropower facilities, from fuel cells that are not fossil-fueled, and from biomass, solar, wind, and geothermal resources.	New Mexico has a relatively large amount of wind generation currently for its small population. New resources are not required until 2015, at which time they are brought in as wind generation.
Oregon	Large utility targets: 5% in 2011, 15% in 2015, 20% in 2020 and 25% in 2025. Large utility sales represented 73% of total sales in 2002. Medium utilities 10% by 2025 Small utilities 5% by 2025.	

Washington	Washington state RPS: 3% by 2012, 9% by 2016, 15% by 2020. Eligible resources include wind, solar, geothermal, biomass, tidal. Oregon officials have been discussing the need for an RPS, and the governor has proposed 25% by 2025.	

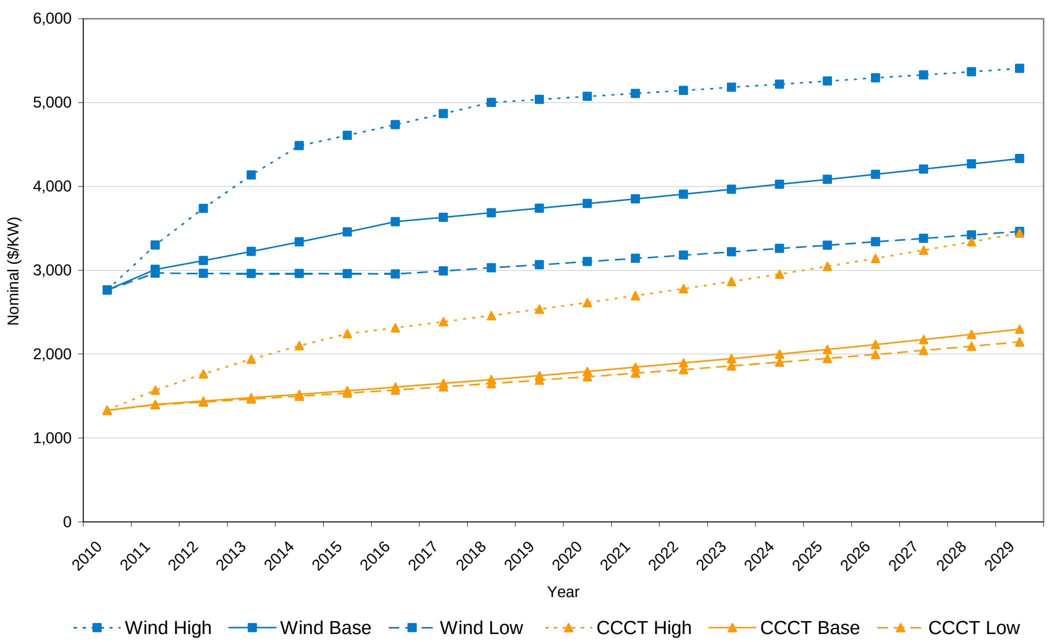
C. Generic Resource Costs and Characteristics

Generic Resource Costs (2008$)	Units	CCCT	CCCTwCCS	Peaker	Coal SCPC	IGCC	IGCCwCCS	Wind	Long Haul Wind	Solar CST	Biomass	Geothermal
Capacity	*MW*	275	250	160	250	250	250	100	100	50	20	25
Capital Cost	*$/KW*	$1,257	$2,470	$1,240	$4,079	$4,527	$5,960	$2,433	$3,753	$4,950	$2,704	$3,449
O&M - Fixed	*$/kW-yr*	$22.00	$35.07	$23.92	$48.52	$68.14	$80.19	$40.00	$40.00	$63.00	$80.00	$132.00
O&M - Variable	*$/MWh*	$3.00	$4.27	$1.40	$6.67	$4.24	$6.45	$2.00	$2.00	$0.00	$3.00	$1.80
Availability	*%*	95%	95%	98%	90%	85%	85%	30%	36%	28%	85%	95%
Capacity Credit	*%*	93%	93%	93%	93%	93%	93%	5%	5%	5%	93%	93%
Heat Rate - GT	*Btu/kWh*	7,038	8,424	8,600	8,998	8,573	10,544				14,000	
Heat Rate - Duct Firing	*Btu/kWh*	8,800										
Fixed Gas Transportation	*$/Dth per day*	$0.50	$0.50	$0.18								
Fixed Gas Transportation	*$/kW-yr*	$30.83	$36.90	$4.52								
Fuel Basis Differential	*$/MWh*	$4.32	$5.18	$5.28								
Electric Transmission - Fixed	*$/kW-yr*	$3.63	$3.63	$3.63	$86.48	$86.48	$86.48	$56.80	$125.23	$20.94	$3.63	$23.12
Electric Transmission - Variable	*$/MWh*	$0.00	$0.00	$0.00	$4.53	$4.53	$4.53	$8.32	$16.96	$2.02	$0.00	$2.23
Emissions:												
CO_2	*lbs/MMBtu*	117	0	117	212.67	212.67	0					
SO_2	*lbs/MMBtu*	0.01	0.01	0.01	0.07	0.07	0.06					
NOX	*lbs/MMBtu*	0	0	0	0.12	0.03	0.03					
Hg	*lbs/MMBtu*											
Location		*PSE Control*	*PSE Control*	*PSE Control*	*MT/WY/Alberta*	*MT/WY/Alberta*	*MT/WY/Alberta*	*WA/OR*	*MT/WY/Alberta/BC*	*SE OR*	*PSE Control*	*OR/ID*
First year Available		*2010*	*2025*	*2012*	*2018*	*2020*	*2025*	*2010*	*2018*	*2014*	*2012*	*2018*

D. Generic Resource Capital Costs Escalation Profiles

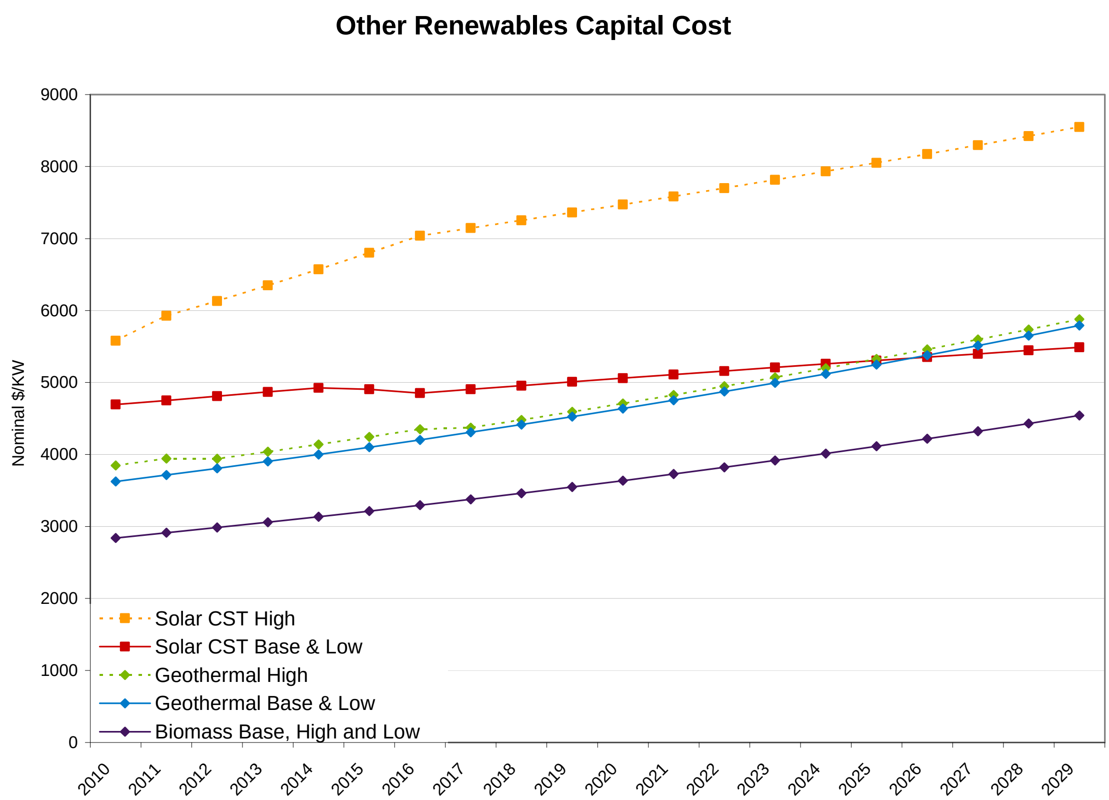
The estimated cost of generic resources is based on bids received in response to our formal 2007 Request for Proposals (RFP), along with information obtained during 2008 as part of the PSE's ongoing market activity. Bid prices received were not firm and were occasionally revised upward. The cost of each resource is escalated at varying rates over the 20-year time horizon. PSE hired ION Consulting to develop potential range of cost escalation rates for gas combined cycle plants and wind plants. We used those studies as a starting point to develop the cost escalation rates, as shown below. PSE also used the Energy Information Administration's "Annual Energy Outlook 2008" escalation for solar capital costs. The conventional coal and IGCC escalation costs were based on the Producer's Price Index (PPI) and the cost of resources. Biomass and Geothermal were kept constant in real terms; in other words, the nominal cost rises at the same rate as inflation (a 2.5% annual inflation rate was assumed in this analysis).

Wind and CCCT Capital Cost



The larger range in cost escalations for wind versus combined cycle plants is based on the relative importance of supply chain shortages in the wind development chain. For example, increased world-wide gear manufacturing for wind plants may reduce costs in the future, or lack of such increase could increase wind plant costs as demand for wind generators continues to grow. The ION studies illustrate cost uncertainty with combined cycle plant costs including things like turbines, but the gas combined cycle supply chain appears to have fewer such critical factors in short supply relative to the wind plant supply chain. The high resource cost assumptions for wind and CCCT were adjusted in the first five years. The capital cost assumptions were taken from the last three IRPs and then trended from 2010-2015. The same cost escalation of wind was applied to the Long Haul Wind resource and likewise, the same cost escalation of a CCCT was also applied to the Peaker and CCCTwCCS resources.

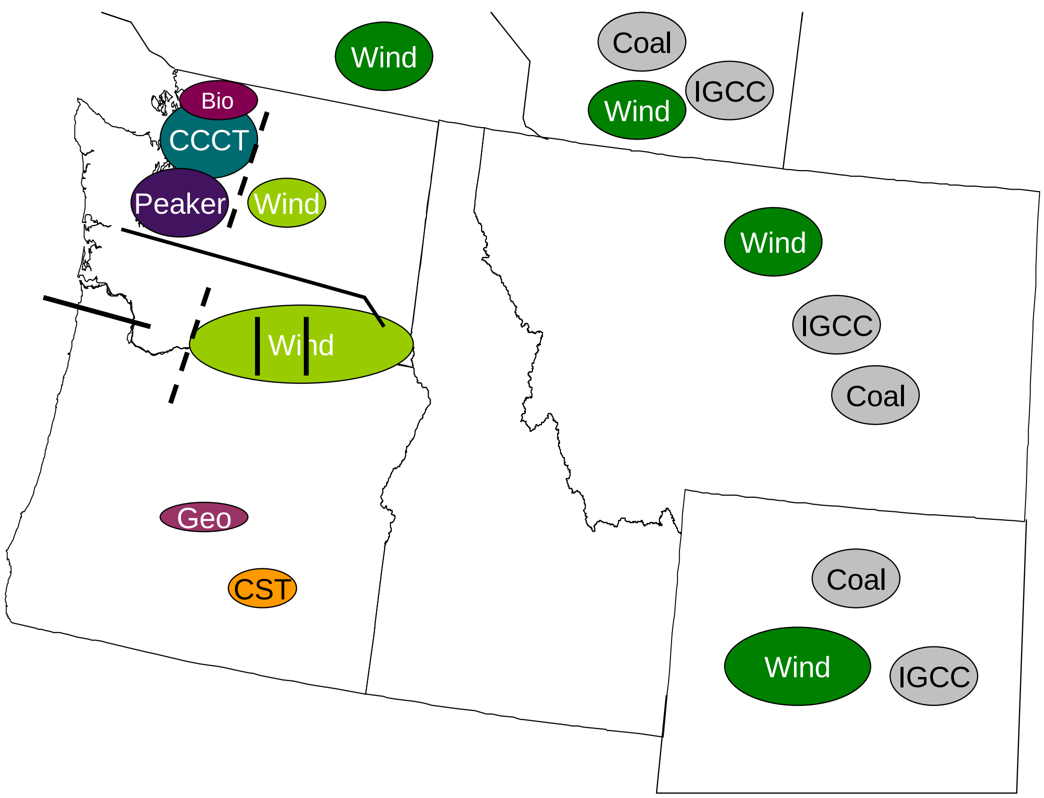
The chart below shows the capital cost escalation assumptions for Solar CST, Geothermal and Biomass.



E. Wind Capacity Credit

For the 2009 IRP, PSE is using 5% of plant name plate capacity for wind capacity credit when evaluating wind resources. We adopted the current recommendation that is being evaluated by the Pacific Northwest Resource Adequacy Forum, which was presented to the NWPCC.

F. Diagram of Resource Locations



G. Updated Planning Standard

We have updated our planning standard to include a 15% planning reserve margin for capacity. The “B2 Energy Planning Standard” used for our last three resource plans represented a reasonable balance of cost and risk in 2003 when it was adopted, but much has changed since then (See Chapter 5). Resource alternatives are now quite different (coal was considered a low price-risk option in 2003 for instance), and regional approaches to assessing adequacy have developed substantive guidelines. In fact, PSE collaborated with the NW Regional Resource Adequacy Forum[2] on the adoption of a Loss of Load Probability approach to planning that is common in other parts of the country.

From 2003 through 2007, PSE used a planning standard that was based on meeting “energy” demand in the worst month of the year (December), in which a 13 ^{o} Fahrenheit one-hour peak load condition was used, unrelated to the loss of load probability. This approach could have resulted in lower planning reserve margins than is believed to be acceptable today.

The following summarizes how we derived the 15% planning reserve margin standard:

The primary objective of our capacity planning standard analysis was to determine the appropriate level of planning reserve margin for PSE. Planning reserve margin for capacity is, in general, defined as the appropriate level of generation resource capacity reserves required to provide for a minimum acceptable level of system generation reliability. This is one of the key constraints in any capacity expansion planning model because it is important to maintain a uniform reliability standard throughout the planning period to obtain comparable capacity expansion plans. This planning reserve margin is measured as:

Reserve Margin = (Generation Capacity – Normal Peak Loads)/Normal Peak Loads

The appropriate level of planning reserve margin is typically identified in terms of its relationship with the loss of load probability (LOLP). LOLP is further defined as the probability of system loads greater than resource capability in any given hour, or

LOLP = Probability [-(Generation Capacity-Loads)>0].

Thus, as the reserve margin increases, one would expect that the loss of load probability decreases also. Because of uncertainties in loads due to extreme temperature events and resource capabilities due to outages and operating reserves, it is necessary to examine the probabilities using a Monte Carlo analysis.

[2] A description of the NW Regional Resource Adequacy Forum and the standards adopted can be found at: http://www.nwcouncil.org/energy/resource/Default.asp

The starting point for the Monte Carlo simulation analysis is the short-term winter peaking analysis completed every summer for the subsequent winter. The analysis identifies various resources available to meet the 13^{o} F, one-hour, predicted peak load, given available transmission capability. Historical data tells us that December is when the peak load condition is typically experienced. The resources included are Colstrip, Mid Columbia and western Washington hydroelectric resources, several gas plants (simple- and combined-cycle units), purchased power contracts, and market purchases up to the available transmission capability. The following sources of variation were considered:

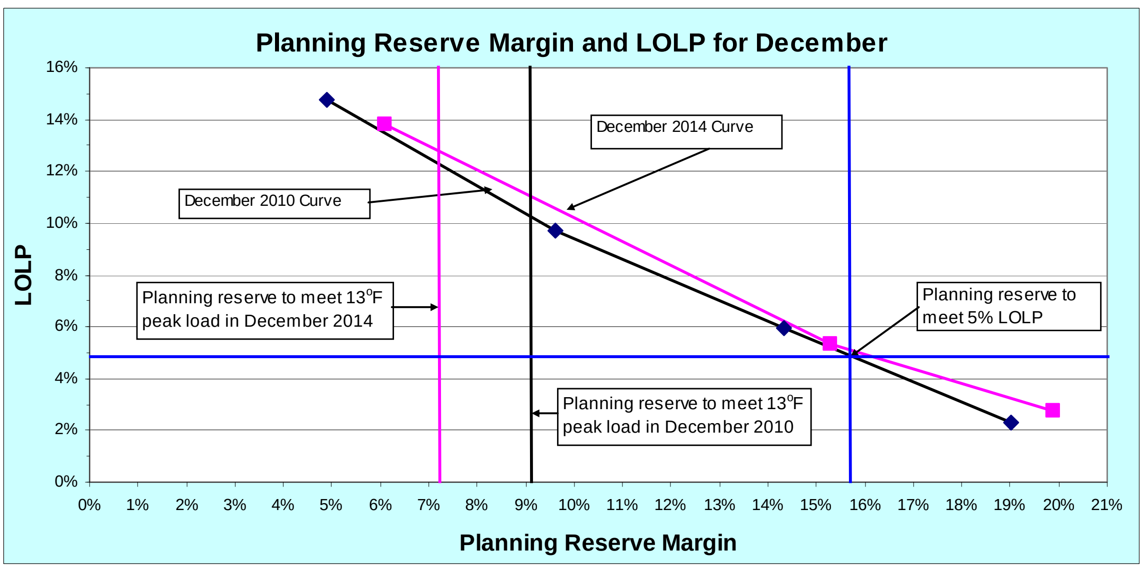
1. Forced Outage Rate for Thermal Units - modeled as a combination of an outage event and duration of an outage event (skewed beta distribution with fixed endpoints), subject to minimum up and down time conditions and total outage rate equal to GRC reported outage rate;
2. Hourly System Loads – modeled as an econometric function of hourly temperature for the month, and using the hourly temperature data in the last 100 years to preserve its chronological order;
3. Mid Columbia and Baker Hydropower – modeled as a binomial distribution with the critical hydro water year at 1/70th probability;
4. Market Purchases – modeled as 50% from hydropower with same variability as Mid Columbia resources; 50% from thermal with same variability as a combined cycle unit since it is difficult to determine the exact source of market purchases;
5. Load Forecast Error – modeled as a discrete distribution so that load error is +/- 1% for 60% of the trials, with a range of +/-3.5%.

As mentioned above, loss of load probability is defined as the number of trials where we observed a loss of load over the total number of trials. 3,000 trials were conducted. Such a large number was chosen because at this level the resulting loss of load frequency becomes very stable. The simulation is also done for all hours in 2010 and all hours in 2014. This allows us to capture the effects of increasing loads and the expiration of some Mid Columbia hydropower contracts, as well as non utility generator (NUG) contracts and other short-term purchase contracts.

The goal of the simulation analysis for any hour is to run the simulation for the existing resource and load conditions, which imply an existing reserve margin. Loss of load probability associated with this reserve margin is then computed based on the 3,000 Monte Carlo draws of the risk variables. Generating capacity is then incremented using a combined-cycle plant as the “typical” plant added which results in a higher reserve margins. Again, the loss of load probability associated with this higher reserve margin is computed based on the Monte Carlo simulation of the risk variables. The process is repeated until the loss of load probability is reduced to an industry standard level.

The results of these simulations are shown in Figure 5-3. The figure illustrates that the planning reserve margin implied by a 5% LOLP is around 15.8% for both years. The figure also demonstrates that the loss of load probability implied by meeting the 13^o Fahrenheit peak loads from the B2 Energy Planning Standard is much higher (10% for December 2010 and 13% for December 2014) if no additional resources are added. The 5% LOLP is chosen to be consistent with the regionally adopted loss of load for resource adequacy standards. Similar LOLP analyses were performed for every month, primarily to reflect seasonal hydropower availability. We focused discussion on December because we found that if we have resources adequate to meet the 5% LOLP in December, we will have resources sufficient to meet that reliability threshold during the rest of the year.

Figure 5-3
Planning Reserve and LOLP



II. Output

A. Aurora Electric Prices and Avoided Costs

Below is a series of tables with the AURORA price forecasts for the different scenarios. Consistent with WAC 480-107-055, this schedule of estimated Mid Columbia power prices is intended to provide only general information to potential bidders about the avoided costs of power supply. It does not provide a guaranteed contract price for electricity.

Monthly Flat Mid-C Prices
(Nominal $/MWH)

2007 Trends

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	69.19	73.22	65.48	54.78	49.40	51.20	59.72	62.54	61.60	59.56	68.19	67.10	61.83
2011	66.28	69.85	62.48	52.48	49.81	51.84	60.74	63.25	62.32	59.99	67.67	66.05	61.06
2012	82.31	85.90	81.17	73.01	71.86	72.40	78.34	80.24	79.84	79.48	84.57	81.09	79.18
2013	84.60	88.53	84.11	76.36	74.05	75.02	81.26	83.48	83.19	81.97	86.53	85.06	82.01
2014	82.76	84.93	80.16	78.92	71.68	70.83	76.57	81.42	76.83	78.53	80.95	84.92	79.04
2015	85.98	87.81	83.13	81.74	75.75	75.79	80.59	84.84	80.22	81.82	84.50	89.25	82.62
2016	89.15	92.04	87.27	84.03	76.91	77.05	82.10	86.75	81.91	83.65	88.79	94.51	85.35
2017	95.70	97.68	92.86	89.07	81.44	81.08	86.88	90.87	85.58	87.92	92.99	98.54	90.05
2018	98.98	101.48	97.23	93.32	86.25	85.87	90.95	95.35	90.49	91.36	95.83	100.97	94.01
2019	101.74	104.10	100.13	97.32	91.08	90.24	94.98	98.82	94.95	95.14	99.15	104.37	97.67
2020	105.28	106.87	103.30	100.36	94.00	93.82	98.17	102.25	98.79	99.02	103.16	107.77	101.07
2021	109.97	111.54	108.38	105.21	97.61	97.55	101.40	106.42	102.78	103.39	107.94	111.74	105.33
2022	115.21	116.84	113.71	109.71	102.20	102.16	105.81	111.59	107.36	108.31	112.47	116.28	110.14
2023	119.42	120.49	116.82	113.24	106.70	106.64	110.31	116.29	111.91	113.10	117.14	120.35	114.37
2024	127.45	129.24	125.77	116.83	109.56	109.25	113.77	119.77	115.96	116.46	124.65	127.98	119.72
2025	130.42	132.82	128.43	120.26	113.18	112.49	117.76	123.04	120.53	121.07	127.50	130.62	123.18
2026	134.52	134.88	131.48	125.05	117.99	116.75	121.40	128.08	125.97	126.57	132.64	134.43	127.48
2027	139.32	140.92	137.21	129.95	123.00	121.64	126.53	132.87	131.36	132.13	140.39	140.43	132.98
2028	146.61	148.05	142.66	135.56	128.55	127.53	132.68	138.74	136.92	138.13	147.84	146.95	139.18
2029	153.46	154.67	149.20	141.82	133.09	131.09	137.93	144.26	142.81	142.55	152.90	154.25	144.84

2007 Business As Usual (BAU)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	68.96	73.65	65.84	54.12	49.43	51.28	59.76	62.52	61.47	59.49	68.54	66.94	61.83
2011	66.82	69.87	62.13	52.68	49.54	51.41	60.16	63.00	61.79	59.78	67.24	65.82	60.85
2012	66.53	68.93	61.84	53.76	51.70	52.12	61.76	63.86	61.76	60.83	67.97	65.96	61.42
2013	67.82	70.90	63.72	55.39	52.58	52.47	63.23	66.01	64.44	62.52	68.65	69.40	63.09
2014	63.62	65.32	57.73	56.34	48.85	47.06	57.03	62.03	56.59	57.89	61.44	67.03	58.41
2015	64.65	65.70	58.44	57.70	49.94	48.97	57.95	63.31	57.68	59.04	63.42	69.45	59.69
2016	66.36	68.43	59.85	57.71	49.18	48.04	56.85	63.57	57.92	58.50	66.23	72.98	60.47
2017	70.49	71.57	62.43	59.27	51.18	49.79	59.04	65.70	59.61	61.15	68.15	74.54	62.74
2018	72.08	73.20	65.38	62.05	53.73	51.40	60.66	68.23	62.80	63.25	69.02	75.73	64.79
2019	73.38	74.42	66.16	63.88	55.84	53.46	62.67	70.09	65.19	65.06	70.72	77.10	66.50
2020	73.90	74.63	66.19	63.89	55.07	53.54	62.61	69.63	65.50	64.78	71.99	78.44	66.68
2021	76.45	77.76	68.97	66.21	57.04	55.72	64.38	71.76	67.15	66.84	74.51	80.55	68.95
2022	78.72	79.72	70.97	67.77	59.89	58.56	66.76	74.34	69.54	69.85	76.45	81.25	71.15
2023	79.94	80.26	71.41	68.70	61.89	60.23	68.66	76.67	71.17	72.06	78.00	81.97	72.58
2024	84.89	85.64	76.83	70.36	63.47	60.83	69.75	77.43	72.17	72.60	82.09	87.14	75.27
2025	85.72	86.11	77.37	71.13	63.69	61.43	70.04	77.38	72.67	73.29	82.21	86.67	75.64
2026	85.93	85.83	77.33	72.37	65.44	63.77	71.81	78.63	74.69	75.37	83.51	86.93	76.80
2027	86.75	87.16	79.34	74.07	67.26	65.67	72.91	79.89	75.88	76.88	86.12	89.28	78.43
2028	89.15	89.51	81.87	75.76	69.89	68.14	75.12	82.11	77.72	79.73	88.50	91.06	80.71
2029	91.26	91.81	85.08	78.75	71.73	68.98	76.76	83.78	79.26	81.13	89.21	92.98	82.56

Green World (GW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	81.41	84.31	78.38	69.66	61.89	60.23	73.92	78.83	77.75	72.22	88.28	89.54	76.37
2011	84.40	85.26	76.03	68.66	60.86	59.82	72.31	79.76	73.19	68.29	82.51	85.21	74.69
2012	105.87	109.53	104.54	97.41	91.27	89.66	97.53	102.52	97.46	96.16	104.19	104.14	100.02
2013	107.86	110.55	105.88	101.05	94.81	93.97	100.76	106.23	100.77	100.15	103.49	105.28	102.57
2014	114.39	118.26	114.15	111.28	105.40	104.80	111.08	115.93	109.99	110.24	113.48	116.22	112.10
2015	120.43	123.84	119.34	116.58	110.37	111.31	117.74	121.45	115.10	115.49	119.40	122.96	117.83
2016	128.35	133.77	128.88	124.21	116.53	117.55	124.82	128.92	122.48	122.59	128.68	132.43	125.77
2017	136.93	141.48	136.43	130.22	123.37	123.73	130.67	135.66	129.24	129.69	135.69	138.74	132.66
2018	148.21	151.41	147.72	141.23	134.10	133.01	140.00	146.53	141.91	140.32	147.03	150.00	143.45
2019	153.34	156.54	153.19	146.22	138.45	138.10	145.42	151.87	148.14	145.75	152.90	155.38	148.78
2020	152.37	156.07	153.22	145.51	137.49	136.82	146.22	152.57	148.45	146.37	153.49	156.49	148.76
2021	157.61	161.19	157.58	149.12	140.40	141.15	149.35	156.78	151.70	150.02	158.24	160.37	152.79
2022	161.91	165.54	161.76	152.67	146.23	145.85	154.14	161.72	155.89	154.92	162.17	163.60	157.20
2023	164.98	168.50	165.23	156.58	149.64	150.82	158.29	165.72	159.77	158.57	166.21	166.93	160.94
2024	169.43	174.25	169.23	156.92	149.56	148.84	159.04	166.48	159.96	157.55	169.13	170.82	162.60
2025	171.95	176.41	171.41	159.09	151.33	149.52	160.89	167.82	162.26	160.24	171.83	172.86	164.63
2026	175.54	178.35	173.97	161.68	153.79	153.27	163.56	170.09	165.93	163.52	175.56	176.08	167.61
2027	173.28	177.66	172.65	161.34	154.18	154.05	163.03	170.19	165.06	163.92	175.10	175.68	167.18
2028	178.20	182.14	177.45	164.36	158.15	158.76	167.50	174.59	168.05	168.27	179.94	179.92	171.44
2029	182.76	187.23	182.02	169.34	160.82	160.56	171.02	177.82	172.28	170.84	183.26	183.79	175.14

Low Growth (LG)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	58.91	59.92	55.52	47.33	37.19	36.43	41.21	44.20	47.42	47.07	57.81	61.85	49.57
2011	60.39	60.32	53.02	47.04	36.33	35.69	39.96	44.61	43.28	44.13	52.45	57.97	47.93
2012	58.41	58.55	51.55	46.16	36.30	35.08	39.05	42.73	41.53	43.54	49.62	54.36	46.41
2013	54.35	52.91	46.28	44.68	36.08	34.62	39.54	43.98	41.75	43.83	45.81	50.89	44.56
2014	51.05	51.76	44.86	45.14	36.63	35.65	40.90	45.38	42.48	45.40	47.34	53.52	45.01
2015	51.86	51.91	45.85	46.47	38.01	37.51	42.39	46.70	43.76	46.90	48.99	55.87	46.35
2016	52.84	54.21	47.46	46.00	36.78	36.03	41.25	46.38	43.43	45.95	50.82	58.38	46.63
2017	56.90	56.76	49.64	47.51	37.94	37.14	42.37	47.80	44.75	47.91	52.50	59.99	48.44
2018	57.93	58.06	51.42	49.52	40.02	38.68	43.84	49.65	47.13	49.76	53.32	60.91	50.02
2019	58.68	58.55	52.21	50.90	41.69	40.06	44.76	50.45	48.82	50.91	54.14	61.36	51.04
2020	58.50	58.69	51.92	50.84	40.95	39.94	44.47	50.04	49.06	50.61	54.69	62.07	50.98
2021	60.16	60.69	53.97	52.27	42.51	41.54	45.60	51.39	50.27	52.19	56.43	63.43	52.54
2022	62.05	61.74	55.32	53.68	44.67	43.71	47.40	53.31	52.06	54.59	57.82	63.76	54.18
2023	62.61	61.63	55.09	54.22	46.14	44.65	48.58	54.93	53.20	56.22	58.62	64.00	54.99
2024	67.16	66.45	58.87	55.68	46.86	45.24	49.36	55.26	53.59	56.44	62.13	68.27	57.11
2025	67.27	66.14	59.01	56.40	47.77	46.26	50.01	55.93	54.64	57.23	62.15	67.83	57.55
2026	67.18	65.84	59.12	57.49	49.49	48.35	51.79	57.23	56.15	58.71	63.06	67.75	58.51
2027	67.37	66.49	60.30	58.41	50.74	49.58	52.46	58.16	57.17	59.78	64.81	69.33	59.55
2028	69.10	67.87	61.80	59.75	52.98	51.54	54.09	59.65	58.44	61.82	66.35	70.45	61.15
2029	70.55	69.41	63.75	61.98	54.33	52.18	54.90	60.93	59.76	63.10	67.03	72.24	62.51

High Growth (HG)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	83.23	85.64	79.77	71.10	63.79	61.25	75.26	79.96	78.73	74.06	89.33	90.87	77.75
2011	88.07	88.51	79.14	71.95	63.64	61.00	74.57	81.65	75.64	71.55	84.91	88.20	77.40
2012	100.42	102.98	96.40	89.48	83.03	80.81	90.70	95.70	89.20	88.09	96.61	97.35	92.57
2013	95.28	96.85	90.98	86.97	81.18	79.36	88.08	94.40	87.92	87.42	90.82	92.40	89.30
2014	94.18	97.27	91.98	89.17	84.00	82.52	91.81	97.78	90.93	90.75	94.47	97.31	91.85
2015	97.15	100.37	95.44	93.17	87.40	86.60	95.51	100.97	94.01	94.00	98.20	101.92	95.39
2016	101.17	104.95	99.94	95.41	89.38	88.45	97.44	103.47	95.81	96.19	102.62	107.15	98.50
2017	107.18	110.39	104.98	99.61	93.69	92.70	101.40	107.76	99.50	100.54	106.92	110.75	102.95
2018	111.59	114.62	110.43	104.67	98.79	96.95	105.85	112.74	105.00	104.64	110.51	114.58	107.53
2019	115.27	118.50	114.79	109.39	103.51	102.03	110.50	117.13	110.08	108.79	114.96	118.63	111.96
2020	119.04	121.93	118.06	112.66	106.66	105.94	114.24	120.40	113.48	112.53	118.93	123.06	115.58
2021	124.47	128.22	123.61	116.92	111.19	110.68	118.55	125.10	117.67	117.05	124.77	127.95	120.52
2022	129.81	133.18	128.70	121.77	117.19	116.75	124.17	130.35	123.13	122.56	129.90	132.15	125.81
2023	135.92	138.09	133.23	126.84	123.43	122.71	130.67	136.81	129.11	128.59	135.85	137.56	131.57
2024	144.12	147.84	143.52	133.42	129.21	128.14	136.39	141.88	134.20	132.70	143.83	146.26	138.46
2025	148.96	151.85	147.14	137.86	133.48	131.62	140.54	145.68	138.26	137.20	146.78	150.25	142.47
2026	154.08	156.20	152.01	143.18	137.62	137.25	145.19	151.21	143.59	142.89	152.81	154.61	147.55
2027	160.11	162.94	159.54	149.36	143.40	143.18	150.65	157.33	149.96	149.34	160.17	162.29	154.02
2028	167.04	170.99	166.56	154.88	150.06	150.09	157.32	163.36	155.98	155.66	168.23	168.93	160.76
2029	174.28	179.83	174.64	162.32	156.16	155.16	163.09	169.92	163.70	162.56	174.07	176.35	167.67

Very High Gas (VHGas)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	82.89	84.90	79.00	70.44	62.85	61.05	74.78	79.41	78.15	72.65	89.19	90.07	77.11
2011	85.53	86.44	76.30	69.72	62.03	60.27	73.61	80.60	74.44	69.45	83.84	86.73	75.75
2012	98.32	101.37	94.62	88.15	81.82	80.17	89.96	94.73	88.49	87.11	96.09	96.40	91.44
2013	107.78	109.95	102.07	98.45	91.29	89.44	102.42	109.25	100.68	99.35	104.33	106.21	101.77
2014	106.42	110.56	103.03	100.76	94.16	93.35	106.06	112.71	104.19	102.96	108.22	111.11	104.46
2015	109.21	112.85	106.48	103.64	97.15	97.76	109.78	115.19	107.63	106.51	111.96	115.30	107.79
2016	113.44	118.57	111.40	106.08	99.84	99.83	111.72	118.52	109.60	108.34	117.34	121.24	111.33
2017	120.47	123.79	116.57	110.73	105.06	104.47	116.51	123.25	113.64	113.90	122.14	124.95	116.29
2018	124.53	128.70	122.54	116.56	110.18	108.53	120.69	128.47	119.79	118.31	125.87	129.37	121.13
2019	128.81	132.88	126.84	121.28	115.94	113.71	125.97	133.26	125.24	123.46	129.92	133.31	125.89
2020	133.00	136.52	130.27	125.22	118.29	117.82	129.44	136.21	129.53	126.98	134.37	137.76	129.62
2021	138.40	142.51	136.45	129.97	123.50	123.48	133.93	141.37	133.78	131.27	140.58	143.15	134.87
2022	144.35	148.45	142.44	135.23	129.89	129.43	139.46	147.30	139.09	137.07	145.83	147.37	140.49
2023	149.37	152.62	146.39	139.40	136.18	134.55	144.25	152.73	143.80	142.76	151.58	151.31	145.41
2024	158.24	162.25	156.32	145.23	139.88	138.25	148.75	157.37	148.73	146.58	158.62	160.67	151.74
2025	163.58	166.34	160.51	149.50	144.38	143.65	153.63	160.37	152.72	150.64	162.52	164.41	156.02
2026	168.28	171.74	166.51	156.08	151.10	151.26	161.95	167.49	159.20	157.19	168.87	169.90	162.46
2027	173.12	177.69	172.50	162.10	157.37	157.90	167.43	174.16	165.03	163.33	176.03	176.36	168.58
2028	181.39	185.24	180.19	168.75	164.96	165.59	175.54	181.21	171.82	170.73	183.92	183.99	176.11
2029	189.67	194.03	188.68	177.79	171.49	171.20	181.65	188.03	179.59	178.08	189.05	192.19	183.45

Very Low Gas (VLGas)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	54.22	54.61	51.16	42.71	32.93	32.06	35.42	38.11	41.29	41.79	51.65	56.39	44.36
2011	50.15	49.84	46.67	37.77	29.81	28.70	31.25	33.91	36.83	37.57	46.66	50.77	39.99
2012	47.43	46.85	43.93	35.86	27.95	26.57	28.70	31.22	33.77	35.56	44.25	48.71	37.57
2013	48.92	48.35	45.30	36.69	28.14	26.67	29.16	31.71	34.59	35.69	44.11	50.24	38.30
2014	49.63	49.31	46.20	37.39	28.75	27.35	29.67	32.16	35.30	36.33	44.85	51.06	39.00
2015	50.43	50.10	47.14	38.83	29.30	28.17	30.18	32.61	35.86	37.20	45.79	51.61	39.77
2016	49.66	49.28	46.09	36.78	28.15	27.22	29.17	31.81	35.12	36.43	45.63	51.09	38.87
2017	50.68	50.06	46.82	37.56	28.89	27.85	29.82	32.30	35.50	37.12	46.29	51.74	39.55
2018	51.67	51.08	48.06	38.54	29.57	28.17	30.19	33.02	35.98	37.49	46.61	52.87	40.27
2019	52.80	52.02	48.60	39.49	30.15	28.65	30.66	33.40	36.55	38.06	47.04	53.88	40.94
2020	52.88	51.86	48.40	39.18	29.65	28.47	30.64	33.22	36.76	37.97	47.23	53.77	40.83
2021	53.72	52.93	49.66	40.04	30.59	29.45	31.25	33.97	37.43	38.62	48.34	54.79	41.73
2022	54.77	53.88	50.83	41.02	31.55	30.14	31.90	34.70	38.16	39.51	49.30	55.65	42.62
2023	55.82	54.55	51.51	41.33	32.00	30.56	32.31	35.15	38.31	40.00	49.88	56.30	43.14
2024	56.75	55.65	52.81	42.77	32.73	30.97	33.17	36.19	39.31	40.79	50.34	57.65	44.09
2025	57.35	56.37	53.88	43.83	33.25	31.28	33.52	36.70	40.15	41.61	50.98	58.49	44.78
2026	58.25	57.32	55.04	44.76	33.76	31.82	34.16	37.21	40.77	42.41	51.85	59.31	45.56
2027	59.26	58.27	56.10	45.35	34.32	32.25	34.45	37.57	41.37	43.06	52.77	60.30	46.26
2028	60.47	59.07	57.02	46.09	35.05	32.87	34.88	38.20	41.99	43.81	53.62	61.12	47.02
2029	61.68	60.19	58.37	47.11	35.64	33.19	35.42	38.95	42.68	44.28	54.11	62.22	47.82

2009 Trends

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	42.12	45.91	42.40	36.27	33.78	35.57	40.28	41.86	42.20	41.47	48.75	45.97	41.38
2011	46.42	49.85	45.46	37.57	35.59	37.34	42.49	44.39	44.53	43.45	50.07	46.38	43.63
2012	66.89	70.25	67.03	60.44	59.08	59.73	62.84	64.32	64.58	64.57	69.62	66.01	64.61
2013	69.70	73.13	69.93	63.44	61.80	62.29	65.53	67.52	67.62	66.56	71.50	69.03	67.34
2014	73.17	75.84	70.75	69.91	62.79	61.68	65.19	68.86	66.65	69.28	70.36	74.36	69.07
2015	76.98	77.82	73.21	73.43	64.54	64.23	67.05	71.41	68.82	72.26	73.58	78.99	71.86
2016	78.46	79.53	75.71	74.43	64.90	64.71	67.31	71.81	69.10	72.33	75.09	81.81	72.93
2017	83.75	83.98	79.98	78.21	68.30	67.44	70.56	74.88	72.43	75.43	78.72	85.20	76.57
2018	86.89	86.60	83.63	81.61	72.04	71.13	73.76	78.10	77.01	78.76	81.31	88.15	79.92
2019	89.42	89.71	86.32	84.39	74.98	73.92	76.33	80.83	80.51	82.07	84.00	90.46	82.75
2020	91.99	92.56	87.91	86.37	76.55	75.09	78.25	83.43	83.59	85.03	87.57	93.47	85.15
2021	95.97	96.63	92.83	89.85	80.32	77.83	80.82	87.46	87.60	88.76	91.71	97.28	88.92
2022	99.69	99.79	95.55	93.87	84.22	81.65	84.98	91.57	91.81	93.13	95.87	100.09	92.68
2023	103.36	103.12	98.27	97.25	87.93	85.45	88.52	95.49	95.27	97.59	99.39	103.28	96.24
2024	110.29	110.35	105.17	99.93	90.00	87.86	90.92	98.45	98.83	100.20	105.60	110.38	100.66
2025	113.92	113.77	108.05	102.57	92.87	89.95	93.66	101.44	101.81	103.24	108.26	113.71	103.60
2026	117.15	116.13	109.76	106.14	97.01	94.37	97.77	105.50	106.00	107.96	112.52	116.82	107.26
2027	120.34	119.97	113.79	109.79	100.83	98.06	101.45	109.19	109.31	111.95	118.20	121.97	111.24
2028	125.27	125.36	118.54	113.93	105.18	102.54	106.34	113.99	113.61	117.15	123.51	126.26	115.97
2029	130.30	130.62	123.29	119.60	109.03	106.82	110.92	118.16	118.81	121.12	127.09	131.16	120.58

2009 Business As Usual (BAU)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2010	53.70	54.13	50.73	42.51	32.66	31.82	35.30	38.06	41.05	41.67	51.38	55.78	44.07
2011	48.89	48.89	46.02	37.04	29.35	28.16	30.60	33.25	35.92	36.91	45.69	49.80	39.21
2012	46.46	46.45	43.62	35.34	27.79	26.50	28.59	30.90	33.51	35.19	43.46	47.91	37.14
2013	47.68	47.13	44.58	36.32	27.95	26.69	29.03	31.26	34.14	35.04	43.29	49.15	37.69
2014	48.73	48.17	45.52	37.00	28.74	27.34	29.46	31.68	34.87	35.70	43.96	50.11	38.44
2015	49.57	49.33	46.78	38.19	29.30	28.43	30.18	32.43	35.65	36.97	45.17	50.92	39.41
2016	48.67	48.42	45.40	36.48	28.19	27.38	29.48	31.91	34.93	36.20	44.94	50.20	38.52
2017	49.92	49.28	46.21	37.10	28.83	27.96	29.98	32.44	35.34	36.92	45.72	51.01	39.23
2018	50.94	50.33	47.38	38.25	29.27	28.20	30.40	33.01	35.98	37.39	45.95	52.14	39.94
2019	52.04	51.32	48.10	39.09	30.01	28.63	30.80	33.41	36.57	37.88	46.44	53.07	40.61
2020	51.95	50.92	47.44	38.61	29.16	28.07	30.51	33.10	36.51	37.58	46.47	52.94	40.27
2021	52.59	51.86	48.68	39.61	29.79	29.06	31.11	33.85	37.15	38.25	47.57	53.88	41.12
2022	53.90	52.98	50.06	40.53	30.94	29.67	31.79	34.51	37.86	39.23	48.64	54.69	42.07
2023	54.89	53.79	50.50	40.84	31.37	29.95	32.00	35.06	38.14	39.82	49.20	55.53	42.59
2024	55.92	54.84	51.89	42.31	32.21	30.42	32.81	35.79	39.02	40.47	49.80	56.82	43.52
2025	56.49	55.38	52.74	43.11	32.48	30.65	33.16	36.11	39.72	41.19	50.24	57.65	44.08
2026	57.32	56.40	54.07	44.04	33.18	31.33	33.77	36.55	40.31	41.69	50.94	58.54	44.84
2027	58.12	57.18	55.05	44.71	33.77	31.95	34.08	37.10	40.84	42.39	52.00	59.46	45.55
2028	59.21	58.10	55.81	45.10	34.59	32.36	34.49	37.57	41.40	43.20	52.68	59.91	46.20
2029	60.47	58.98	57.26	46.45	34.95	32.65	34.98	38.42	42.06	43.69	53.01	61.33	47.02

B. Electric Demand-Side Screening Results

The results in the following tables were part of the bundles provided by Cadmus Group. See Appendix L for a discussion of Cadmus' methodology and analysis.

Annual Energy Savings (aMW)

Bundles A through E includes Energy Efficiency, Fuel Conversion, Distributed Generation, and Distribution Efficiency

	Bundle A	Bundle B	Bundle C	Bundle D	Bundle E	EISA
2010	27.3	39.4	44.2	47.3	51.3	0.0
2011	55.4	79.7	89.2	95.5	103.4	0.0
2012	84.5	120.9	135.0	144.8	156.6	1.1
2013	109.3	156.4	174.7	187.7	203.4	5.7
2014	133.5	191.3	213.6	230.3	249.9	11.3
2015	158.7	227.0	253.3	273.6	297.1	16.9
2016	185.1	264.3	294.8	318.3	345.8	22.6
2017	210.9	300.5	334.9	361.5	392.9	28.3
2018	237.9	338.4	376.9	406.7	442.0	34.0
2019	265.5	376.9	419.5	452.4	491.7	39.7
2020	270.9	384.2	428.3	461.6	501.7	45.4
2021	274.7	389.2	434.3	468.0	508.6	51.1
2022	279.4	395.5	441.8	475.9	517.2	56.8
2023	284.2	401.9	449.4	483.8	525.9	62.4
2024	290.1	409.9	459.0	493.8	536.7	68.0
2025	294.2	415.2	465.3	500.1	543.6	73.7
2026	299.4	421.9	473.2	508.3	552.5	79.3
2027	304.5	428.4	481.0	515.9	560.8	84.8
2028	310.7	436.5	490.4	525.9	571.7	90.4
2029	315.0	442.1	497.1	532.8	579.2	95.9

Total December Peak Reduction (MW)

Coincidental Peak with System

Bundles A through E includes Energy Efficiency, Fuel Conversion, Distributed Generation, Distribution Efficiency, and Demand Response

	Bundle A	Bundle B	Bundle C	Bundle D	Bundle E	EISA
2010	38.6	57.3	63.1	68.5	75.8	0.0
2011	82.6	119.7	130.8	142.1	156.7	0.0
2012	135.3	190.8	207.8	224.4	245.4	1.0
2013	211.5	285.0	305.8	329.0	357.5	4.8
2014	305.4	396.7	422.9	451.2	486.9	9.8
2015	410.7	519.6	550.4	584.8	627.5	14.7
2016	485.5	612.1	650.9	688.9	739.4	19.3
2017	544.2	688.0	728.3	773.8	830.9	25.0
2018	587.3	748.3	792.1	839.5	903.7	30.1
2019	620.2	800.9	849.1	904.3	975.7	33.9
2020	633.6	813.7	864.2	921.0	993.6	39.4
2021	644.8	831.0	876.9	939.3	1013.6	44.2
2022	653.9	842.6	889.2	952.0	1027.4	48.4
2023	663.0	847.9	900.7	958.8	1035.0	55.2
2024	672.0	857.9	911.5	969.0	1046.2	58.1
2025	682.8	871.6	925.9	984.6	1063.0	63.9
2026	694.1	884.0	938.9	997.7	1077.3	68.7
2027	705.2	902.6	953.3	1017.3	1098.2	73.5
2028	714.7	907.7	964.0	1023.3	1105.0	79.9
2029	724.2	918.4	976.1	1034.6	1117.3	84.8

Annual Costs (Thousands $)

Bundles A through E includes Energy Efficiency, Fuel Conversion, Distributed Generation, Distribution Efficiency, and Demand Response

	Bundle A	Bundle B	Bundle C	Bundle D	Bundle E	EISA
2010	$36,695	$95,345	$138,329	$165,537	$206,501	$0
2011	$37,904	$98,004	$140,744	$168,273	$209,523	$0
2012	$41,933	$102,354	$143,843	$172,653	$214,174	$0
2013	$41,816	$98,605	$136,971	$166,710	$208,592	$0
2014	$45,708	$103,320	$140,822	$173,207	$217,610	$0
2015	$57,505	$116,846	$154,308	$189,227	$234,256	$0
2016	$57,005	$118,377	$156,058	$192,319	$238,101	$0
2017	$57,461	$120,187	$156,673	$193,793	$239,357	$0
2018	$56,789	$117,568	$152,297	$190,133	$236,681	$0
2019	$58,972	$117,937	$151,748	$190,617	$243,539	$0
2020	$34,106	$51,248	$67,454	$94,809	$118,821	$0
2021	$34,729	$51,686	$66,876	$94,972	$119,082	$0
2022	$39,394	$56,722	$71,070	$99,572	$125,194	$0
2023	$39,091	$58,533	$71,503	$100,932	$125,691	$0
2024	$40,827	$76,843	$96,616	$130,124	$158,786	$0
2025	$40,480	$75,319	$93,142	$125,774	$154,189	$0
2026	$38,084	$67,215	$81,765	$112,845	$140,249	$0
2027	$36,218	$58,082	$69,345	$97,462	$118,989	$0
2028	$35,835	$52,007	$60,125	$86,850	$103,320	$0
2029	$32,230	$42,443	$46,497	$71,518	$79,830	$0

C. Electric Integrated Portfolio Results

This chart summarizes the expected costs of the different portfolios in different scenarios. Some portfolios were tested in more than one scenario. At the very least, each portfolio was tested in its “home” scenario. For example, high growth was tested only in the high growth scenario. For comparison purposes, 2007 Trends and 2007 Business as Usual (BAU) portfolios were tested in all scenarios.

Portfolio		Scenario											
	Expected Portfolio cost NPV (Millions $)	2007 Trends	2007 BAU	Green World	Low Growth	High Growth	Very High Gas	Very Low Gas	High Resource Cost	Low Resource Cost	Transport Load	2009 Trends	2009 BAU
	2007 Trends No DSR	$27,172											
	2007 Trends	$23,292	$18,455	$27,918	$15,348	$26,287	$26,895	$14,265				$20,222	
	2007 BAU	$23,424	$18,374	$28,159	$15,084	$26,264	$27,009	$13,985				$20,159	
	Green World			$28,913									
	Low Growth				$15,307								
	High Growth					$28,191							
	Very High Gas						$26,622						
	Very Low Gas							$14,051					
	High Resource Cost								$24,206				
	Low Resource Cost									$22,619			
	Transport Load										$24,263		
	High RPS	$23,689											
	Low RPS	$22,278											
	B2 Energy_2007	$23,672	$18,946									$20,060	
	2009 Trends	$23,513	$18,287									$20,186	
	2009 BAU												$13,292
	All Peaker											$19,661	
	All Baseload											$20,010	
	Proposed Plan	$24,005	$19,063									$20,665	$13,819

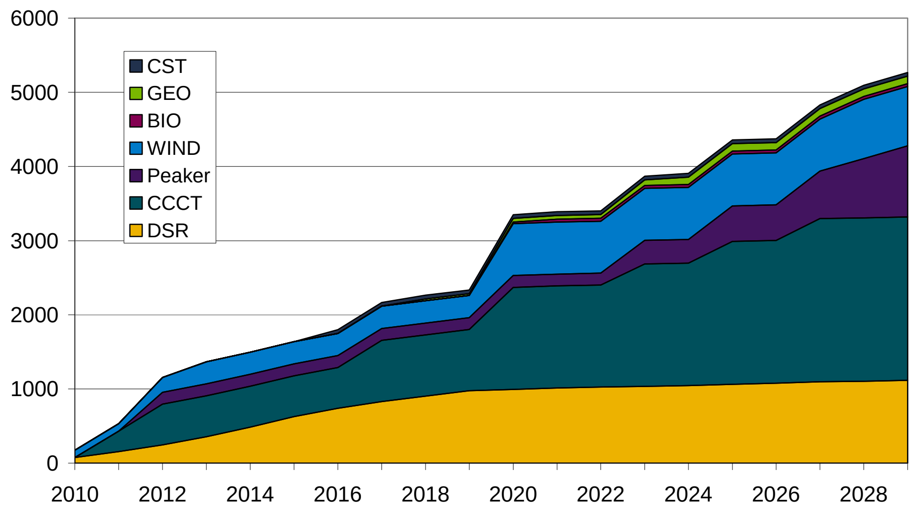
Risk Simulations

Portfolio: 2007 Trends
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	100	76	176
2011	-	-	275	-	-	-	81	356
2012	-	160	275	-	-	100	89	624
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	50	-	112	162
2017	-	-	275	-	-	-	92	367
2018	-	-	-	25	-	-	73	98
2019	-	-	-	-	-	-	72	72
2020	20	-	550	25	-	400	18	1,013
2021	20	-	-	-	-	-	20	40
2022	-	-	-	-	-	-	14	14
2023	-	160	275	25	-	-	8	468
2024	-	-	-	25	-	-	11	36
2025	-	160	275	-	-	-	17	452
2026	-	-	-	-	-	-	14	14
2027	-	160	275	-	-	-	21	456
2028	-	160	-	-	-	100	7	267
2029	-	160	-	-	-	-	12	172
Total Additions	40	960	2,200	100	50	800	1,117	5,267
Percent	1%	18%	42%	2%	1%	15%	21%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for Each Scenario

20-year NPV in Millions $	2007 Trends	2007 BAU	2009 Trends	Green World	Low Growth	High Growth	Very High Gas	Very Low Gas
Revenue from Power Sales	($211)	($151)	($478)	($141)	($1,017)	($125)	($108)	($1,098)
Cost of Power Purchase	$5,185	$4,174	$3,636	$8,945	$955	$8,160	$9,853	$610
Demand Side Resources	$1,369	$1,369	$1,369	$1,369	$1,369	$1,369	$1,369	$1,369
Generic Revenue Requirement	$9,599	$7,495	$8,936	$10,886	$7,190	$9,591	$9,543	$7,107
Variable Cost of Existing Fleet	$6,404	$4,178	$5,628	$5,870	$5,474	$6,452	$5,402	$4,782
End Effects Generic	$946	$1,390	$1,132	$990	$1,377	$841	$837	$1,495
Expected Cost	$23,292	$18,455	$20,222	$27,918	$15,348	$26,287	$26,895	$14,265
Expected Cost $/MWh	85.36	67.59	75.80	104.76	57.56	93.35	98.57	52.21

Expected Revenue Requirements with Input Simulations - 100 trials

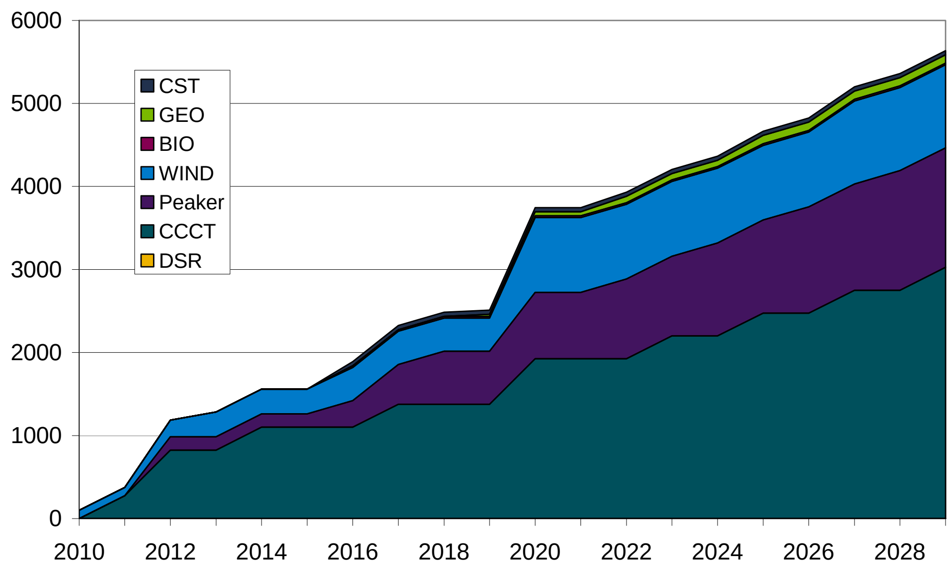
Mean	$22,979	$18,196
Average of 10 Worst	$23,852	$18,729
Annual Volatility	12%	9%

Portfolio: 2007 Trends No DSR
DSR Bundle: None

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	100	-	100
2011	-	-	275	-	-	-	-	275
2012	-	160	550	-	-	100	-	810
2013	20	-	-	-	-	100	-	120
2014	-	-	275	-	-	-	-	275
2015	-	-	-	-	-	-	-	-
2016	-	160	-	-	50	100	-	310
2017	-	160	275	-	-	-	-	435
2018	-	160	-	-	-	-	-	160
2019	20	-	-	25	-	-	-	45
2020	-	160	550	25	-	500	-	1,235
2021	20	-	-	-	-	-	-	20
2022	-	160	-	25	-	-	-	185
2023	-	-	275	-	-	-	-	275
2024	-	160	-	-	-	-	-	160
2025	-	-	275	25	-	-	-	300
2026	-	160	-	-	-	-	-	160
2027	-	-	275	-	-	100	-	375
2028	-	160	-	-	-	-	-	160
2029	-	-	275	-	-	-	-	275
Total Additions	60	1,440	3,025	100	50	1,000	-	5,675
Percent	1%	25%	53%	2%	1%	18%	0%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for Each Scenario

20-year NPV in Millions $	2007 Trends
Revenue from Power Sales	($113)
Cost of Power Purchase	$6,692
Demand Side Resources	$0
Generic Revenue Requirement	$12,917
Variable Cost of Existing Fleet	$6,405
End Effects Generic	$1,270
Expected Cost	$27,172
Expected Cost $/MWh	99.46

Expected Revenue Requirements with Input Simulations - 100 trials

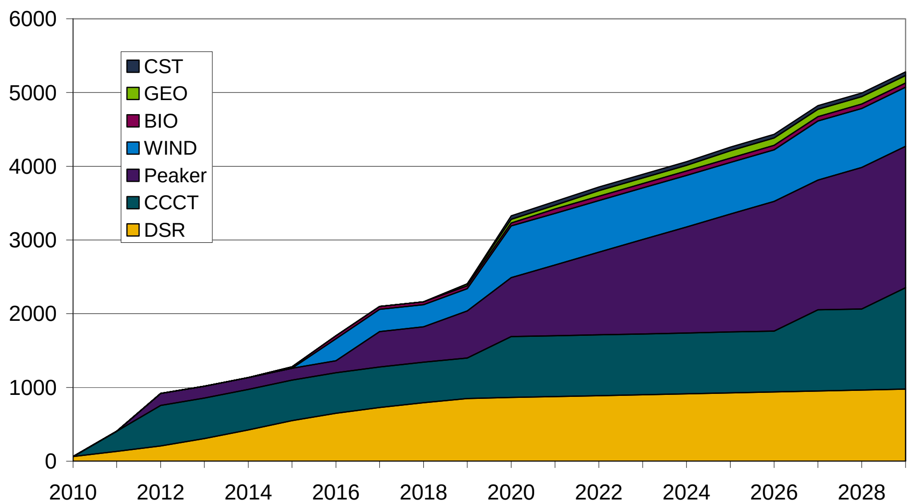
Mean	$26,833
Average of 10 Worst	$27,864
Annual Volatility	13%

Portfolio: 2009 Business As Usual
DSR Bundle: C

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	63	63
2011	-	-	275	-	-	-	68	343
2012	-	160	275	-	-	-	77	512
2013	-	-	-	-	-	-	98	98
2014	-	-	-	-	-	-	117	117
2015	20	-	-	-	-	-	128	148
2016	20	-	-	-	-	300	101	421
2017	-	320	-	-	-	-	77	397
2018	-	-	-	-	-	-	64	64
2019	-	160	-	25	-	-	57	242
2020	-	160	275	25	50	400	15	925
2021	20	160	-	-	-	-	13	193
2022	-	160	-	25	-	-	12	197
2023	-	160	-	-	-	-	12	172
2024	-	160	-	-	-	-	11	171
2025	-	160	-	25	-	-	14	199
2026	-	160	-	-	-	-	13	173
2027	-	-	275	-	-	100	14	389
2028	-	160	-	-	-	-	11	171
2029	-	-	275	-	-	-	12	287
Total Additions	60	1,920	1,375	100	50	800	976	5,281
Percent	1%	36%	26%	2%	1%	15%	18%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for Each Scenario

20-year NPV in Millions $	2007 Trends	2007 BAU	2009 Trends	Green World	Low Growth	High Growth	Very High Gas	Very Low Gas
Revenue from Power Sales	($97)	($97)	($310)	($60)	($692)	($74)	($62)	($794)
Cost of Power Purchase	$7,469	$5,420	$5,618	$12,110	$1,699	$10,540	$12,373	$1,196
Demand Side Resources	$844	$844	$844	$844	$844	$844	$844	$844
Generic Revenue Requirement	$7,828	$6,484	$7,719	$8,458	$6,248	$7,727	$7,661	$6,300
Variable Cost of Existing Fleet	$6,404	$4,178	$5,628	$5,870	$5,474	$6,452	$5,402	$4,782
End Effects Generic	$975	$1,546	$1,161	$936	$1,510	$775	$791	$1,658
Expected Cost	$23,424	$18,374	$20,660	$28,159	$15,084	$26,264	$27,009	$13,985
Expected Cost $/MWh	85.74	67.26	77.36	105.55	56.54	93.15	98.86	51.19

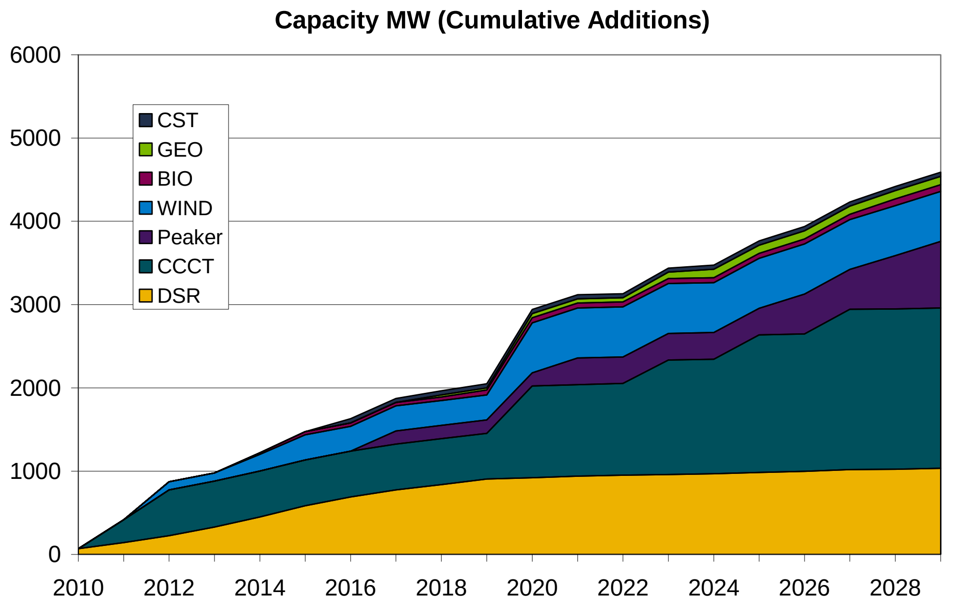
Expected Revenue Requirements with Input Simulations - 100 trials

Mean	$23,171	$18,185
Average of 10 Worst	$24,041	$18,719
Annual Volatility	12%	10%

Portfolio: Green World
DSR Bundle: D

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	69	69
2011	-	-	275	-	-	-	74	349
2012	-	-	275	-	-	100	82	457
2013	-	-	-	-	-	-	105	105
2014	20	-	-	-	-	100	122	242
2015	20	-	-	-	-	100	134	254
2016	-	-	-	-	50	-	104	154
2017	-	160	-	-	-	-	85	245
2018	-	-	-	25	-	-	66	91
2019	20	-	-	-	-	-	65	85
2020	-	-	550	25	-	300	17	892
2021	-	160	-	-	-	-	18	178
2022	-	-	-	-	-	-	13	13
2023	-	-	275	25	-	-	7	307
2024	-	-	-	25	-	-	10	35
2025	-	-	275	-	-	-	16	291
2026	-	160	-	-	-	-	13	173
2027	-	-	275	-	-	-	20	295
2028	20	160	-	-	-	-	6	186
2029	-	160	-	-	-	-	11	171
Total Additions	80	800	1,925	100	50	600	1,035	4,590
Percent	2%	17%	42%	2%	1%	13%	23%	100%



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	Green World
Revenue from Power Sales	($83)
Cost of Power Purchase	$10,173
Demand Side Resources	$1,078
Generic Revenue Requirement	$10,565
Variable Cost of Existing Fleet	$5,870
End Effects Generic	$1,310
Expected Cost	$28,913

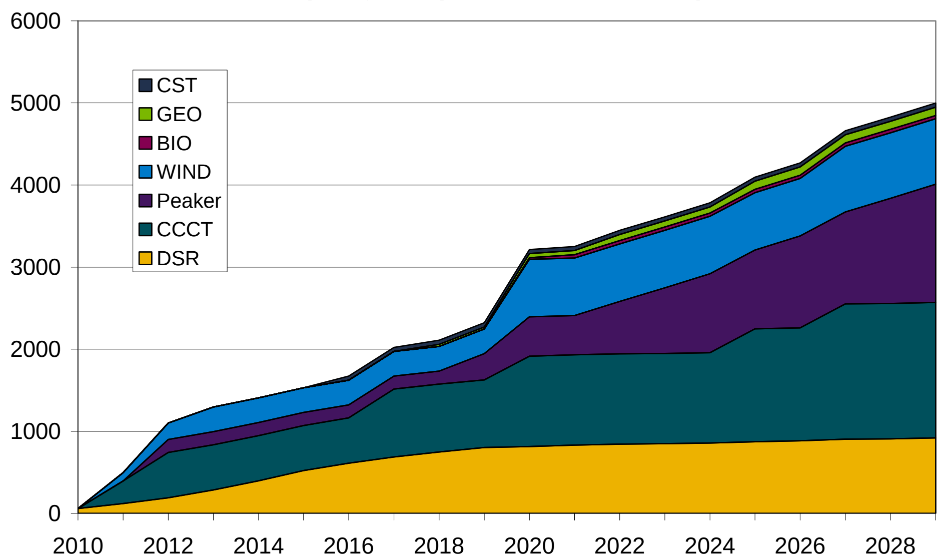
Expected Cost $/MWh	108.38

Portfolio: Low Growth
DSR Bundle: B

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	57	57
2011	-	-	275	-	-	100	62	437
2012	-	160	275	-	-	100	71	606
2013	-	-	-	-	-	100	94	194
2014	-	-	-	-	-	-	112	112
2015	-	-	-	-	-	-	123	123
2016	-	-	-	-	50	-	93	143
2017	-	-	275	-	-	-	76	351
2018	-	-	-	25	-	-	60	85
2019	-	160	-	-	-	-	53	213
2020	20	160	275	25	-	400	13	893
2021	20	-	-	-	-	-	17	37
2022	-	160	-	25	-	-	12	197
2023	-	160	-	-	-	-	5	165
2024	-	160	-	-	-	-	10	170
2025	-	-	275	25	-	-	14	314
2026	-	160	-	-	-	-	12	172
2027	-	-	275	-	-	100	19	394
2028	-	160	-	-	-	-	5	165
2029	-	160	-	-	-	-	11	171
Total Additions	40	1,440	1,650	100	50	800	918	4,998
Percent	1%	29%	33%	2%	1%	16%	18%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for the Scenario

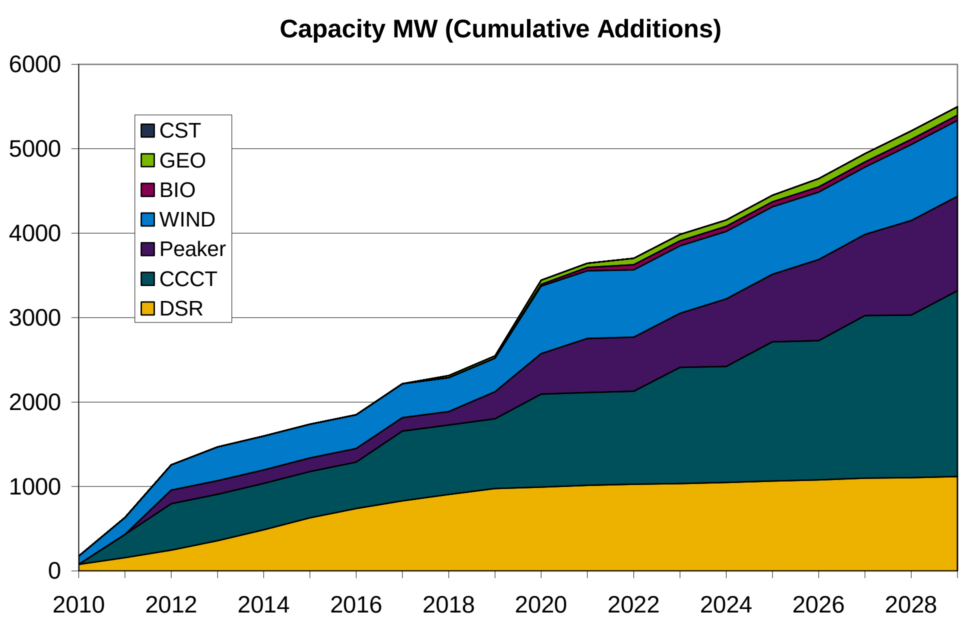
20-year NPV in Millions $	Low Growth
Revenue from Power Sales	($385)
Cost of Power Purchase	$1,981
Demand Side Resources	$598
Generic Revenue Requirement	$6,791
Variable Cost of Existing Fleet	$4,913
End Effects Generic	$1,408
Expected Cost	$15,307

Expected Cost $/MWh	57.38

Portfolio: High Growth
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	100	76	176
2011	-	-	275	-	-	100	81	456
2012	-	160	275	-	-	100	89	624
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	-	-	112	112
2017	-	-	275	-	-	-	92	367
2018	-	-	-	25	-	-	73	98
2019	-	160	-	-	-	-	72	232
2020	20	160	275	25	-	400	18	898
2021	20	160	-	-	-	-	20	200
2022	20	-	-	25	-	-	14	59
2023	-	-	275	-	-	-	8	283
2024	-	160	-	-	-	-	11	171
2025	-	-	275	-	-	-	17	292
2026	-	160	-	25	-	-	14	199
2027	-	-	275	-	-	-	21	296
2028	-	160	-	-	-	100	7	267
2029	-	-	275	-	-	-	12	287
Total Additions	60	1,120	2,200	100	-	900	1,117	5,497
Percent	1%	20%	40%	2%	0%	16%	20%	100%



Revenue Requirements with Expected Inputs for the Scenario

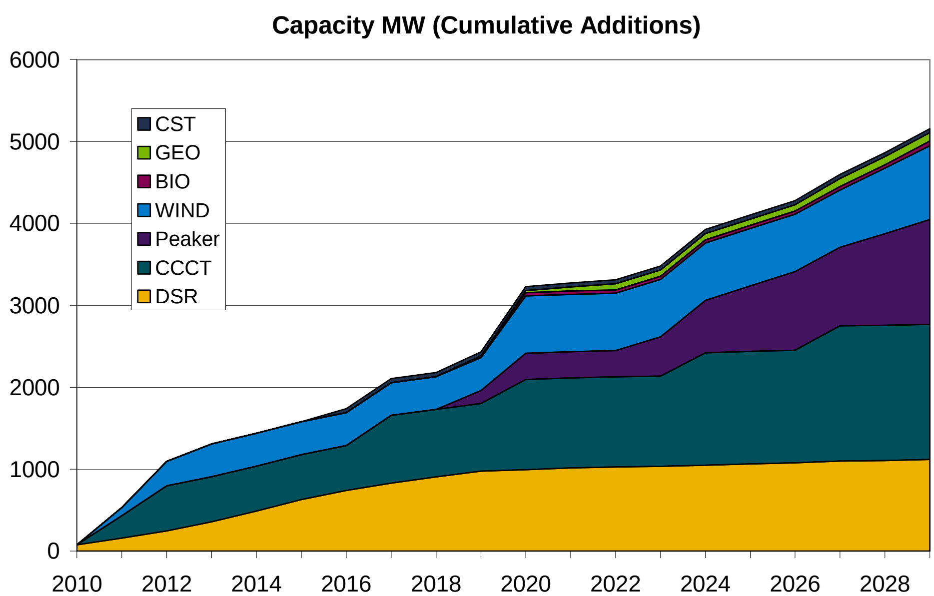
20-year NPV in Millions $	High Growth
Revenue from Power Sales	($124)
Cost of Power Purchase	$8,396
Demand Side Resources	$1,369
Generic Revenue Requirement	$10,783
Variable Cost of Existing Fleet	$6,452
End Effects Generic	$1,316
Expected Cost	$28,191

Expected Cost $/MWh	99.99

Portfolio: Very High Gas
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	76	76
2011	-	-	275	-	-	100	81	456
2012	-	-	275	-	-	200	89	564
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	50	-	112	162
2017	-	-	275	-	-	-	92	367
2018	-	-	-	-	-	-	73	73
2019	20	160	-	-	-	-	72	252
2020	20	160	275	25	-	300	18	798
2021	-	-	-	25	-	-	20	45
2022	-	-	-	25	-	-	14	39
2023	-	160	-	-	-	-	8	168
2024	-	160	275	-	-	-	11	446
2025	-	160	-	-	-	-	17	177
2026	-	160	-	-	-	-	14	174
2027	-	-	275	25	-	-	21	321
2028	-	160	-	-	-	100	7	267
2029	20	160	-	-	-	100	12	292
Total Additions	60	1,280	1,650	100	50	900	1,117	5,157
Percent	1%	25%	32%	2%	1%	17%	22%	100%



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	Very High Gas
Revenue from Power Sales	($90)
Cost of Power Purchase	$10,631
Demand Side Resources	$1,369
Generic Revenue Requirement	$8,514
Variable Cost of Existing Fleet	$5,402
End Effects Generic	$796
Expected Cost	$26,622

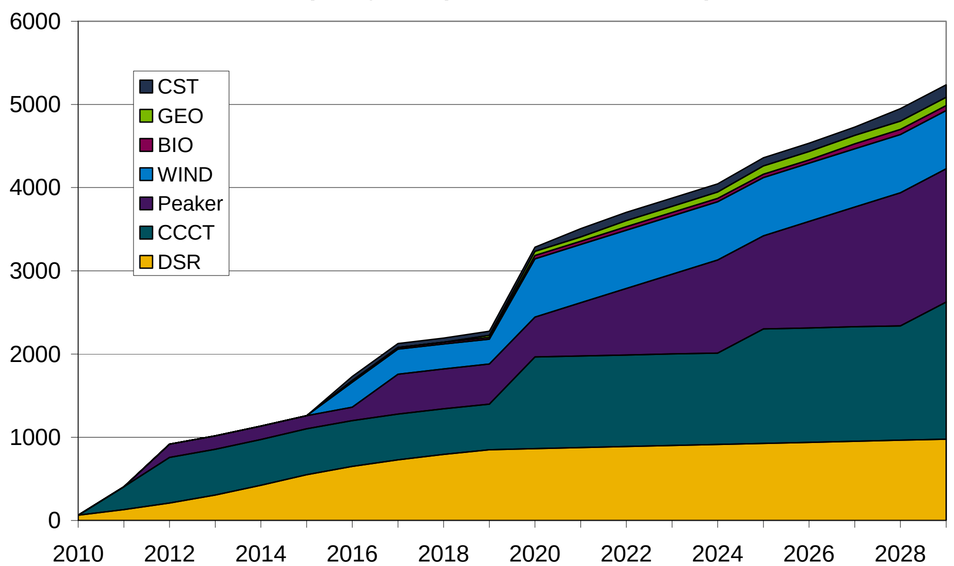
Expected Cost $/MWh	97.45

Portfolio: Very Low Gas
DSR Bundle: C

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	63	63
2011	-	-	275	-	-	-	68	343
2012	-	160	275	-	-	-	77	512
2013	-	-	-	-	-	-	98	98
2014	-	-	-	-	-	-	117	117
2015	-	-	-	-	-	-	128	128
2016	20	-	-	-	50	300	101	471
2017	-	320	-	-	-	-	77	397
2018	-	-	-	-	-	-	64	64
2019	-	-	-	25	-	-	57	82
2020	20	-	550	25	-	400	15	1,010
2021	-	160	-	-	50	-	13	223
2022	-	160	-	25	-	-	12	197
2023	-	160	-	-	-	-	12	172
2024	-	160	-	-	-	-	11	171
2025	-	-	275	25	-	-	14	314
2026	-	160	-	-	-	-	13	173
2027	20	160	-	-	-	-	14	194
2028	-	160	-	-	50	-	11	221
2029	-	-	275	-	-	-	12	287
Total Additions	60	1,600	1,650	100	150	700	976	5,236
Percent	1%	31%	32%	2%	3%	13%	19%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	Very Low Gas
Revenue from Power Sales	($826)
Cost of Power Purchase	$1,014
Demand Side Resources	$844
Generic Revenue Requirement	$6,552
Variable Cost of Existing Fleet	$4,782
End Effects Generic	$1,684
Expected Cost	$14,051

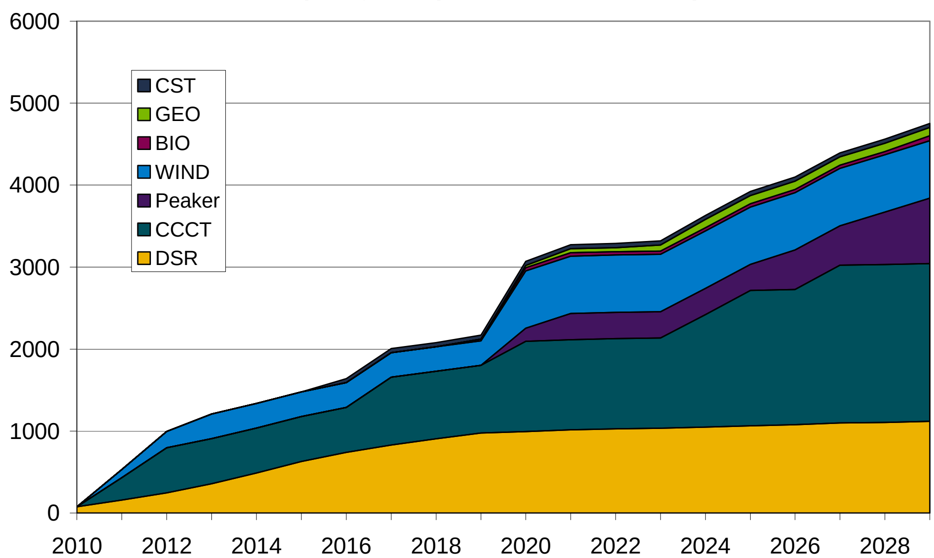
Expected Cost $/MWh	51.43

Portfolio: High Resource Cost
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	76	76
2011	-	-	275	-	-	100	81	456
2012	-	-	275	-	-	100	89	464
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	50	-	112	162
2017	-	-	275	-	-	-	92	367
2018	-	-	-	-	-	-	73	73
2019	20	-	-	-	-	-	72	92
2020	20	160	275	25	-	400	18	898
2021	-	160	-	25	-	-	20	205
2022	-	-	-	-	-	-	14	14
2023	-	-	-	25	-	-	8	33
2024	-	-	275	25	-	-	11	311
2025	-	-	275	-	-	-	17	292
2026	-	160	-	-	-	-	14	174
2027	-	-	275	-	-	-	21	296
2028	-	160	-	-	-	-	7	167
2029	20	160	-	-	-	-	12	192
Total Additions	60	800	1,925	100	50	700	1,117	4,752
Percent	1%	17%	41%	2%	1%	15%	24%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for the Scenario

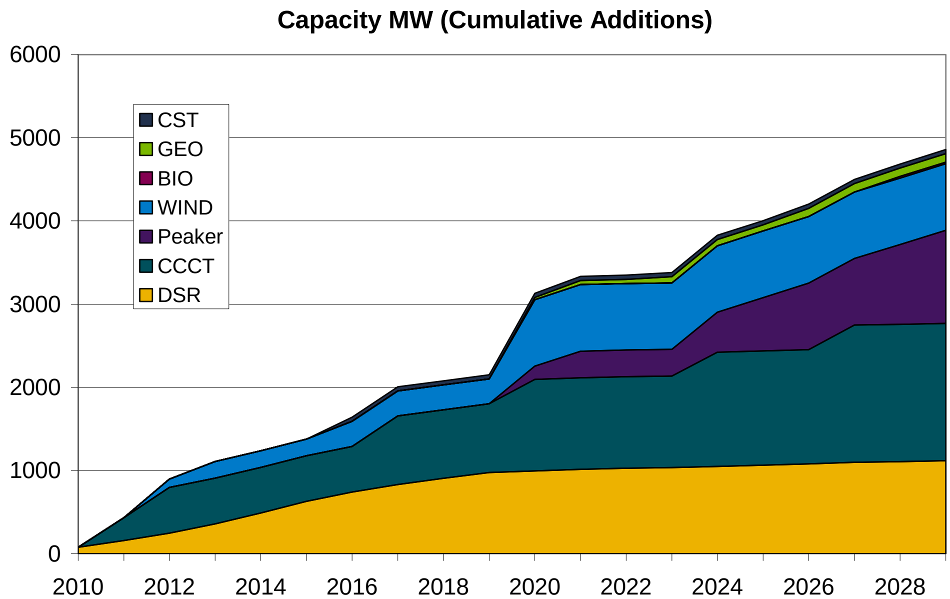
20-year NPV in Millions $	2007 Trends with High Resource
Revenue from Power Sales	($155)
Cost of Power Purchase	$5,777
Demand Side Resources	$1,369
Generic Revenue Requirement	$9,530
Variable Cost of Existing Fleet	$6,404
End Effects Generic	$1,282
Expected Cost	$24,206

Expected Cost $/MWh	88.60

Portfolio: Low Resource Cost
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	76	76
2011	-	-	275	-	-	-	81	356
2012	-	-	275	-	-	100	89	464
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	50	100	112	262
2017	-	-	275	-	-	-	92	367
2018	-	-	-	-	-	-	73	73
2019	-	-	-	-	-	-	72	72
2020	-	160	275	25	-	500	18	978
2021	-	160	-	25	-	-	20	205
2022	-	-	-	-	-	-	14	14
2023	-	-	-	25	-	-	8	33
2024	-	160	275	-	-	-	11	446
2025	-	160	-	-	-	-	17	177
2026	-	160	-	25	-	-	14	199
2027	-	-	275	-	-	-	21	296
2028	20	160	-	-	-	-	7	187
2029	-	160	-	-	-	-	12	172
Total Additions	20	1,120	1,650	100	50	800	1,117	4,857
Percent	0%	23%	34%	2%	1%	16%	23%	100%



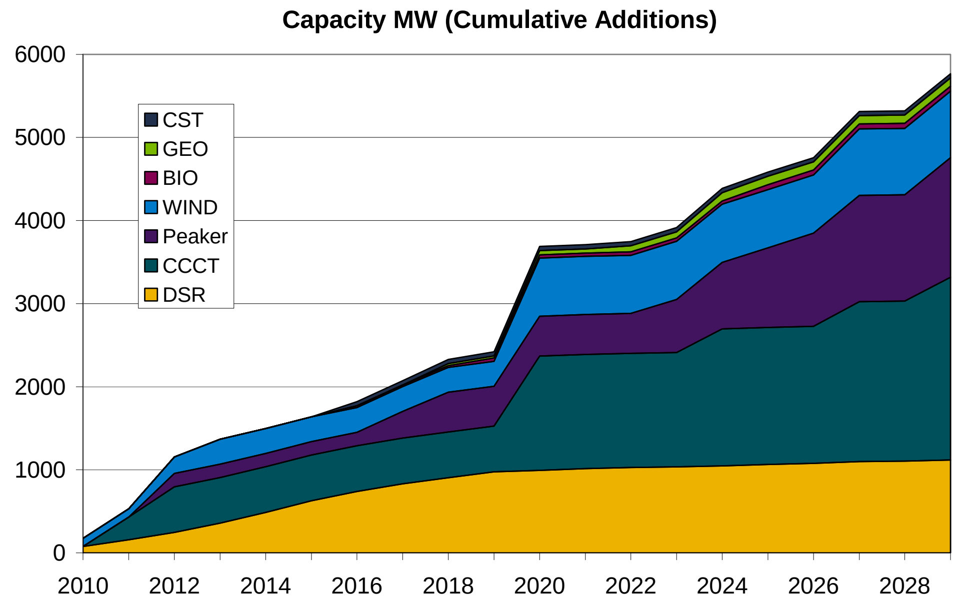
Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2007 Trends with Low Resource
Revenue from Power Sales	($133)
Cost of Power Purchase	$6,110
Demand Side Resources	$1,369
Generic Revenue Requirement	$8,016
Variable Cost of Existing Fleet	$6,404
End Effects Generic	$854
Expected Cost	$22,619
Expected Cost $/MWh	82.79

Portfolio: Transport Load
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	100	76	176
2011	-	-	275	-	-	-	81	356
2012	-	160	275	-	-	100	89	624
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	20	-	-	-	50	-	112	182
2017	-	160	-	-	-	-	92	252
2018	-	160	-	25	-	-	73	258
2019	20	-	-	-	-	-	72	92
2020	-	-	825	25	-	400	18	1,268
2021	-	-	-	-	-	-	20	20
2022	-	-	-	25	-	-	14	39
2023	-	160	-	-	-	-	8	168
2024	-	160	275	25	-	-	11	471
2025	20	160	-	-	-	-	17	197
2026	-	160	-	-	-	-	14	174
2027	-	160	275	-	-	100	21	556
2028	-	-	-	-	-	-	7	7
2029	-	160	275	-	-	-	12	447
Total Additions	60	1,440	2,200	100	50	800	1,117	5,767
Percent	1%	25%	38%	2%	1%	14%	19%	100%



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2007 Trends with Transport
Revenue from Power Sales	($152)
Cost of Power Purchase	$6,002
Demand Side Resources	$1,369
Generic Revenue Requirement	$9,581
Variable Cost of Existing Fleet	$6,404
End Effects Generic	$1,059
Expected Cost	$24,263

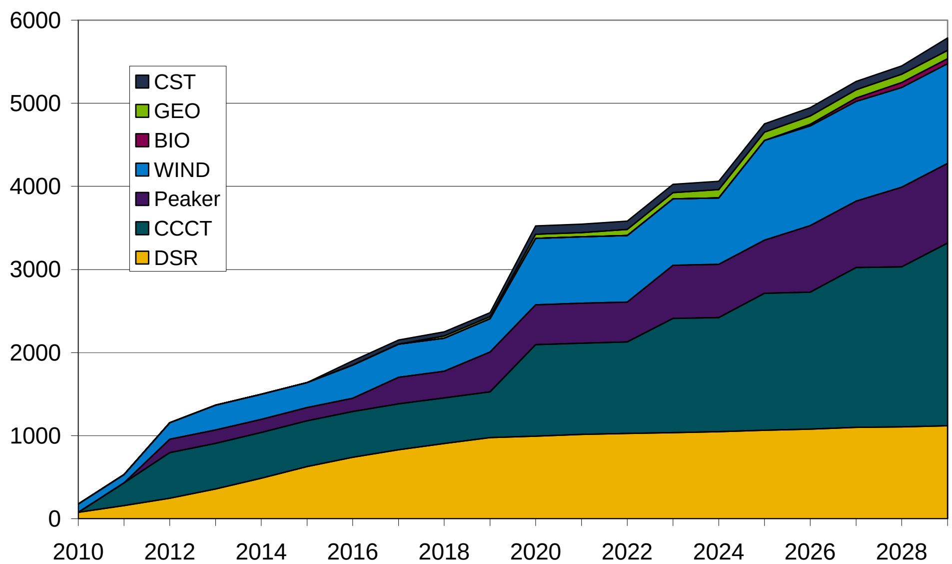
Expected Cost $/MWh	87.15

Portfolio: High RPS
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	100	76	176
2011	-	-	275	-	-	-	81	356
2012	-	160	275	-	-	100	89	624
2013	-	-	-	-	-	100	112	212
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	50	100	112	262
2017	-	160	-	-	-	-	92	252
2018	-	-	-	25	-	-	73	98
2019	-	160	-	-	-	-	72	232
2020	-	-	550	25	50	400	18	1,043
2021	-	-	-	-	-	-	20	20
2022	-	-	-	25	-	-	14	39
2023	-	160	275	-	-	-	8	443
2024	-	-	-	25	-	-	11	36
2025	-	-	275	-	-	400	17	692
2026	20	160	-	-	-	-	14	194
2027	20	-	275	-	-	-	21	316
2028	20	160	-	-	-	-	7	187
2029	-	-	275	-	50	-	12	337
Total Additions	60	960	2,200	100	150	1,200	1,117	5,787
Percent	1%	17%	38%	2%	3%	21%	19%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2007 Trends
Revenue from Power Sales	($198)
Cost of Power Purchase	$5,489
Demand Side Resources	$1,369
Generic Revenue Requirement	$9,571
Variable Cost of Existing Fleet	$6,410
End Effects Generic	$1,047
Expected Cost	$23,689
Expected Cost $/MWh	86.71

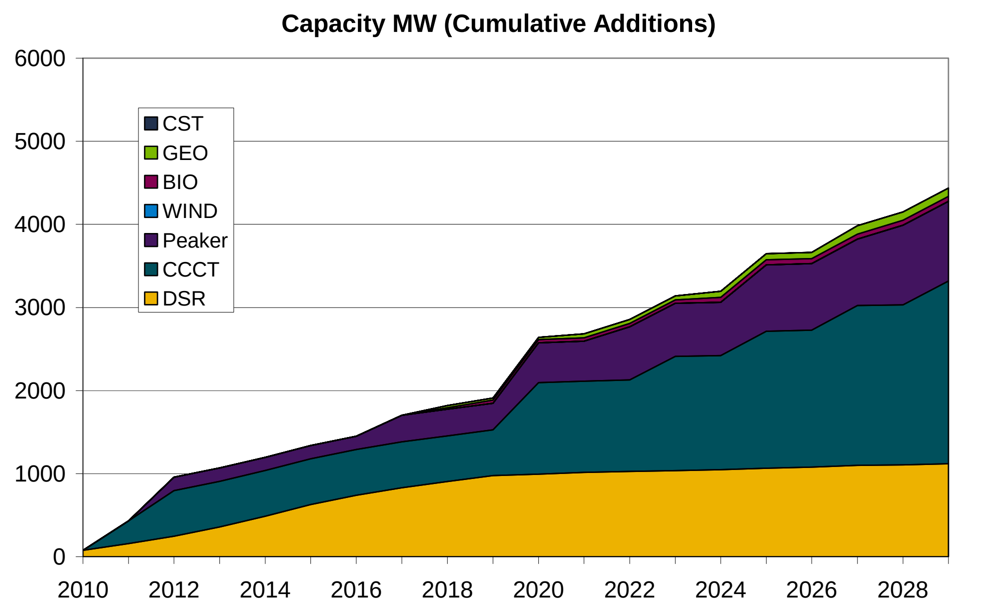
Expected Revenue Requirements with Input Simulations - 100 trials

Mean	$23,450
Average of 10 Worst	$24,433
Annual Volatility	11%

Portfolio: Low RPS
DSR Bundle: E

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	76	76
2011	-	-	275	-	-	-	81	356
2012	-	160	275	-	-	-	89	524
2013	-	-	-	-	-	-	112	112
2014	-	-	-	-	-	-	129	129
2015	-	-	-	-	-	-	141	141
2016	-	-	-	-	-	-	112	112
2017	-	160	-	-	-	-	92	252
2018	20	-	-	25	-	-	73	118
2019	20	-	-	-	-	-	72	92
2020	-	160	550	-	-	-	18	728
2021	-	-	-	25	-	-	20	45
2022	-	160	-	-	-	-	14	174
2023	-	-	275	-	-	-	8	283
2024	20	-	-	25	-	-	11	56
2025	-	160	275	-	-	-	17	452
2026	-	-	-	-	-	-	14	14
2027	-	-	275	25	-	-	21	321
2028	-	160	-	-	-	-	7	167
2029	-	-	275	-	-	-	12	287
Total Additions	60	960	2,200	100	-	-	1,117	4,437
Percent	1%	22%	50%	2%	0%	0%	25%	100%



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2007 Trends
Revenue from Power Sales	($110)
Cost of Power Purchase	$6,882
Demand Side Resources	$1,369
Generic Revenue Requirement	$6,928
Variable Cost of Existing Fleet	$6,369
End Effects Generic	$842
Expected Cost	$22,278
Expected Cost $/MWh	81.55

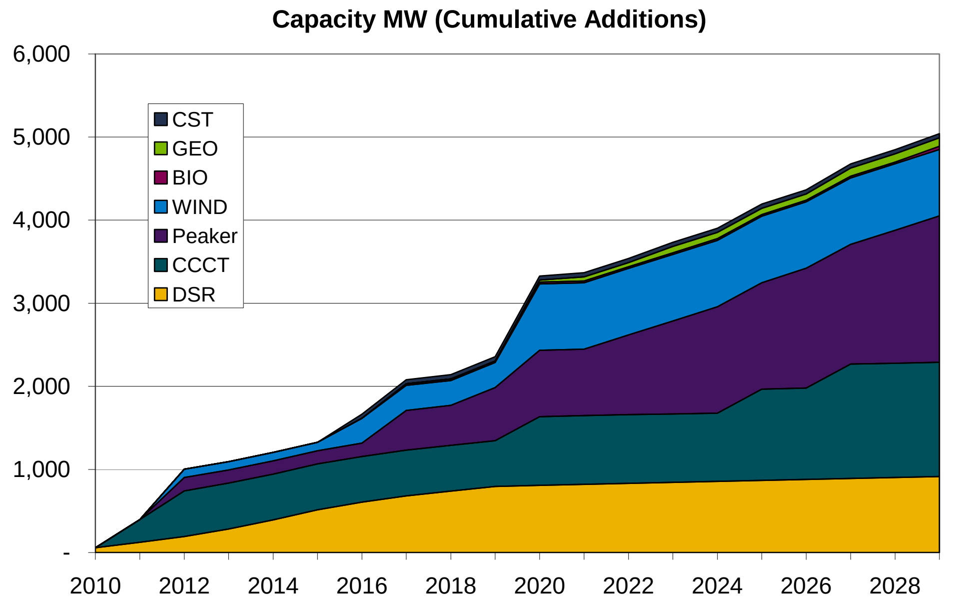
Expected Revenue Requirements with Input Simulations - 100 trials

Mean	$22,505
Average of 10 Worst	$23,410
Annual Volatility	13%

Portfolio: 2009 Trends
DSR Bundle: B

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	58	58
2011	-	-	275	-	-	-	63	338
2012	-	160	275	-	-	100	71	606
2013	-	-	-	-	-	-	91	91
2014	-	-	-	-	-	-	110	110
2015	-	-	-	-	-	-	122	122
2016	-	-	-	-	50	200	90	340
2017	20	320	-	-	-	-	76	416
2018	-	-	-	-	-	-	58	58
2019	-	160	-	-	-	-	57	217
2020	-	160	275	25	-	500	13	973
2021	-	-	-	25	-	-	14	39
2022	-	160	-	-	-	-	11	171
2023	-	160	-	25	-	-	8	193
2024	-	160	-	-	-	-	10	170
2025	-	-	275	-	-	-	15	290
2026	-	160	-	-	-	-	12	172
2027	-	-	275	25	-	-	13	313
2028	-	160	-	-	-	-	10	170
2029	20	160	-	-	-	-	12	192
Total Additions	40	1,760	1,375	100	50	800	914	5,039
Percent	1%	35%	27%	2%	1%	16%	18%	100%



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2007 Trends	2007 BAU	2009 Trends
Revenue from Power Sales	($93)	($94)	($307)
Cost of Power Purchase	$7,510	$5,497	$5,617
Demand Side Resources	$598	$598	$598
Generic Revenue Requirement	$7,984	$6,600	$7,413
Variable Cost of Existing Fleet	$6,404	$4,179	$5,628
End Effects Generic	$1,110	$1,507	$1,237
Expected Cost	$23,513	$18,287	$20,186
Expected Cost $/MWh	86.07	66.94	75.59

Expected Revenue Requirements with Input Simulations - 100 trials

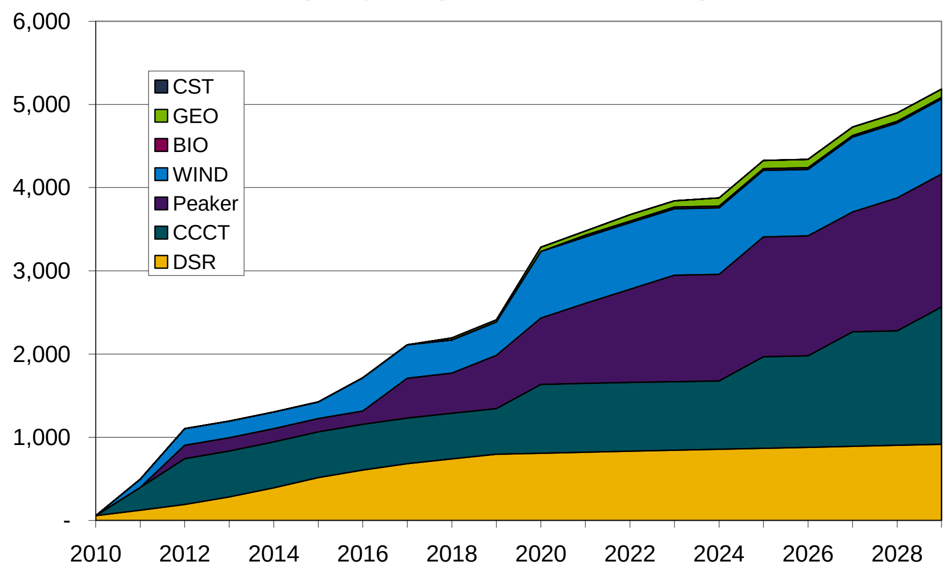
Mean	$20,075
Average of 10 Worst	$20,824
Annual Volatility	13%

Portfolio: 2009 Business As Usual
DSR Bundle: B

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	58	58
2011	-	-	275	-	-	100	63	438
2012	-	160	275	-	-	100	71	606
2013	-	-	-	-	-	-	91	91
2014	-	-	-	-	-	-	110	110
2015	-	-	-	-	-	-	122	122
2016	-	-	-	-	-	200	90	290
2017	-	320	-	-	-	-	76	396
2018	-	-	-	25	-	-	58	83
2019	-	160	-	-	-	-	57	217
2020	-	160	275	25	-	400	13	873
2021	20	160	-	-	-	-	14	194
2022	-	160	-	25	-	-	11	196
2023	-	160	-	-	-	-	8	168
2024	-	-	-	25	-	-	10	35
2025	-	160	275	-	-	-	15	450
2026	-	-	-	-	-	-	12	12
2027	-	-	275	-	-	100	13	388
2028	-	160	-	-	-	-	10	170
2029	-	-	275	-	-	-	12	287
Total Additions	20	1,600	1,650	100	-	900	914	5,184
Percent	0%	31%	32%	2%	0%	17%	18%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2009 BAU
Revenue from Power Sales	($875)
Cost of Power Purchase	$1,069
Demand Side Resources	$598
Generic Revenue Requirement	$6,279
Variable Cost of Existing Fleet	$4,718
End Effects Generic	$1,503
Expected Cost	$13,292

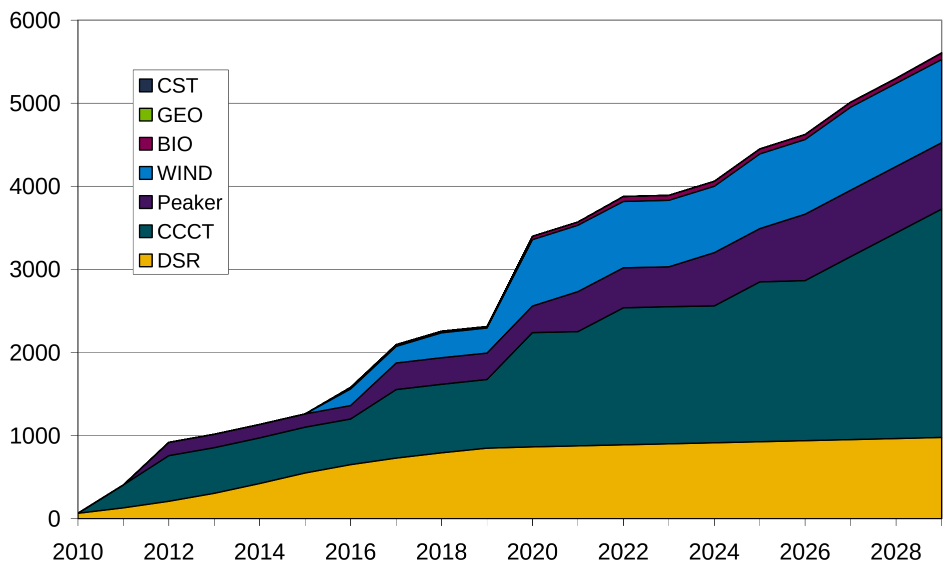
Expected Cost $/MWh	49.77

Portfolio: B2 Energy Planning Standard
DSR Bundle: C

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	63	63
2011	-	-	275	-	-	-	68	343
2012	-	160	275	-	-	-	77	512
2013	-	-	-	-	-	-	98	98
2014	-	-	-	-	-	-	117	117
2015	-	-	-	-	-	-	128	128
2016	20	-	-	-	-	200	101	321
2017	-	160	275	-	-	-	77	512
2018	-	-	-	-	-	100	64	164
2019	-	-	-	-	-	-	57	57
2020	20	-	550	-	-	500	15	1,085
2021	-	160	-	-	-	-	13	173
2022	20	-	275	-	-	-	12	307
2023	-	-	-	-	-	-	12	12
2024	-	160	-	-	-	-	11	171
2025	-	-	275	-	-	100	14	389
2026	-	160	-	-	-	-	13	173
2027	-	-	275	-	-	100	14	389
2028	-	-	275	-	-	-	11	286
2029	20	-	275	-	-	-	12	307
Total Additions	80	800	2,750	-	-	1,000	976	5,606
Percent	1%	14%	49%	0%	0%	18%	17%	100%

Capacity MW (Cumulative Additions)



Revenue Requirements with Expected Inputs for Each Scenario

20-year NPV in Millions $	2007 Trends	2007 BAU	2009 Trends
Revenue from Power Sales	($186)	($120)	($421)
Cost of Power Purchase	$5,721	$4,564	$4,054
Demand Side Resources	$844	$844	$844
Generic Revenue Requirement	$9,975	$7,744	$9,167
Variable Cost of Existing Fleet	$6,404	$4,178	$5,628
End Effects Generic	$914	$1,736	$788
Expected Cost	$23,672	$18,946	$20,060
Expected Cost $/MWh	86.65	69.35	75.11

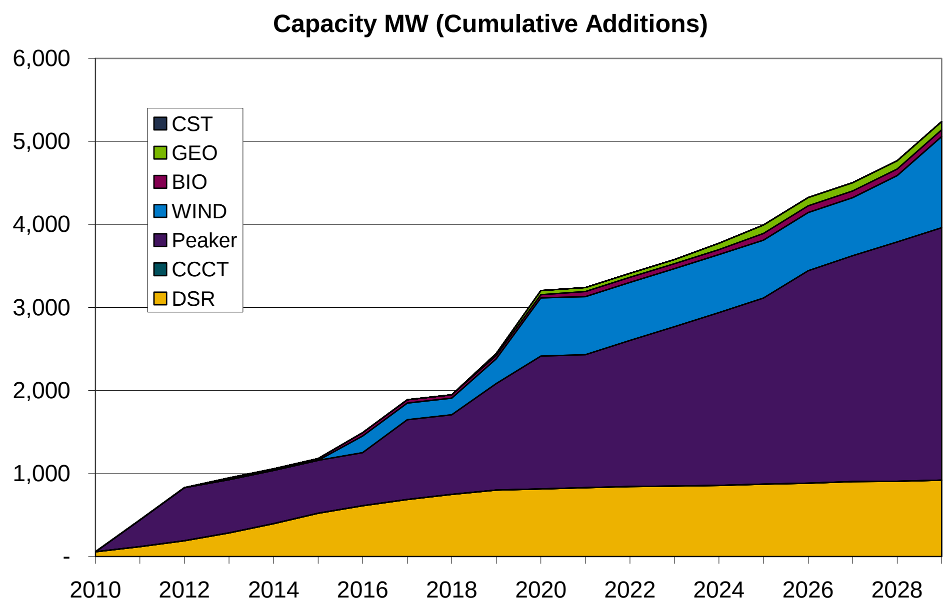
Expected Revenue Requirements with Input Simulations - 100 trials

Mean	$23,348	$18,605
Average of 10 Worst	$24,348	$19,221
Annual Volatility	12%	10%

Portfolio: All Peaker
DSR Bundle: B

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	57	57
2011	-	320	-	-	-	-	62	382
2012	-	320	-	-	-	-	71	391
2013	20	-	-	-	-	-	94	114
2014	-	-	-	-	-	-	112	112
2015	-	-	-	-	-	-	123	123
2016	20	-	-	-	-	200	93	313
2017	-	320	-	-	-	-	76	396
2018	-	-	-	-	-	-	60	60
2019	-	320	-	25	-	100	53	498
2020	-	320	-	25	-	400	13	758
2021	20	-	-	-	-	-	17	37
2022	-	160	-	-	-	-	12	172
2023	-	160	-	-	-	-	5	165
2024	-	160	-	25	-	-	10	195
2025	20	160	-	25	-	-	14	219
2026	-	320	-	-	-	-	12	332
2027	-	160	-	-	-	-	19	179
2028	-	160	-	-	-	100	5	265
2029	-	160	-	-	-	300	11	471
Total Additions	80	3,040	-	100	-	1,100	918	5,238
Percent	2%	58%	0%	2%	0%	21%	18%	100%



Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2009 Trends
Revenue from Power Sales	($326)
Cost of Power Purchase	$8,114
Demand Side Resources	$598
Generic Revenue Requirement	$4,502
Variable Cost of Existing Fleet	$5,628
End Effects Generic	$1,145
Expected Cost	$19,661
Expected Cost $/MWh	73.62

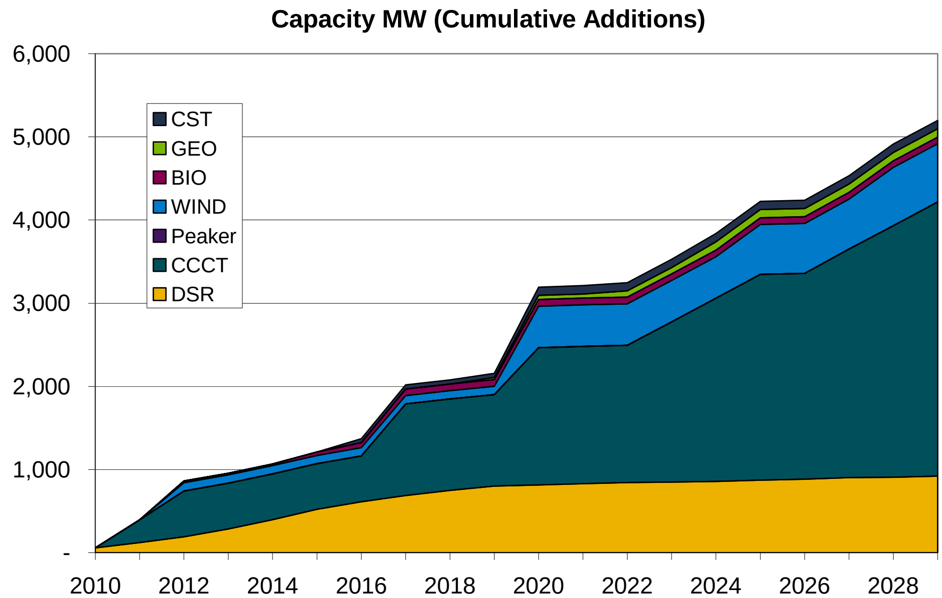
Expected Revenue Requirements with Input Simulations - 100 trials

Mean	$20,053
Average of 10 Worst	$20,798
Annual Volatility	13%

Portfolio: All CCCT Baseload
DSR Bundle: B

Supply Side Additions (Nameplate Capacity in MW)

	BIO	Peaker	CCCT	GEO	CST	WIND	DSR	Annual Additions
2010	-	-	-	-	-	-	57	57
2011	-	-	275	-	-	-	62	337
2012	20	-	275	-	-	100	71	466
2013	-	-	-	-	-	-	94	94
2014	-	-	-	-	-	-	112	112
2015	20	-	-	-	-	-	123	143
2016	20	-	-	-	50	-	93	163
2017	20	-	550	-	-	-	76	646
2018	-	-	-	-	-	-	60	60
2019	-	-	-	25	-	-	53	78
2020	-	-	550	25	50	400	13	1,038
2021	-	-	-	-	-	-	17	17
2022	-	-	-	25	-	-	12	37
2023	-	-	275	-	-	-	5	280
2024	-	-	275	25	-	-	10	310
2025	-	-	275	-	-	100	14	389
2026	-	-	-	-	-	-	12	12
2027	-	-	275	-	-	-	19	294
2028	-	-	275	-	-	100	5	380
2029	-	-	275	-	-	-	11	286
Total Additions	80	-	3,300	100	100	700	918	5,198
Percent	2%	0%	63%	2%	2%	13%	18%	100%

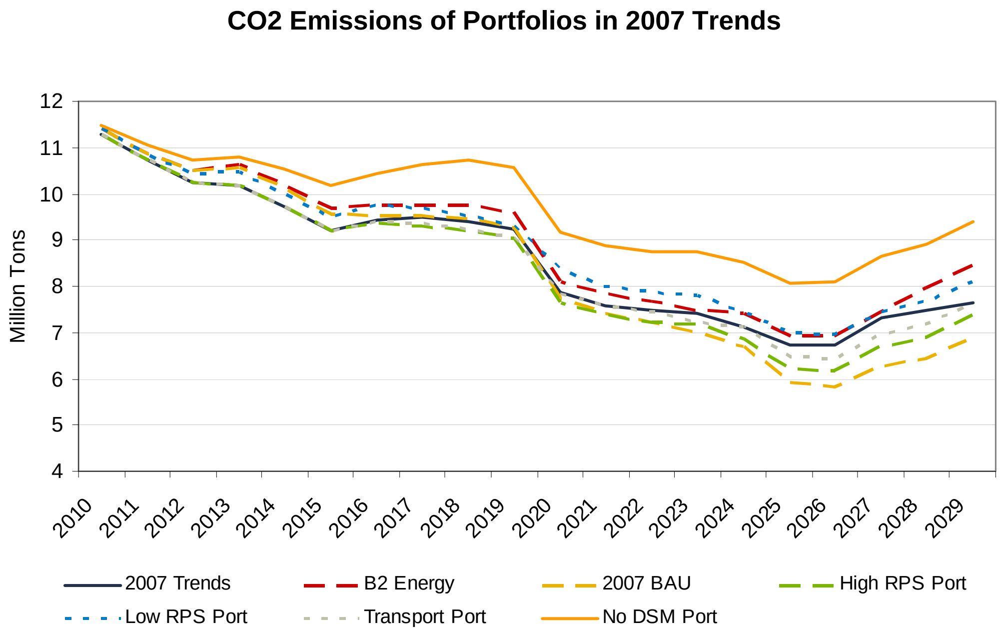


Revenue Requirements with Expected Inputs for the Scenario

20-year NPV in Millions $	2009 Trends
Revenue from Power Sales	($326)
Cost of Power Purchase	$3,056
Demand Side Resources	$598
Generic Revenue Requirement	$9,856
Variable Cost of Existing Fleet	$5,628
End Effects Generic	$1,199
Expected Cost	$20,010
Expected Cost $/MWh	74.93

Expected Revenue Requirements with Input Simulations - 100 trials

Mean	$19,982
Average of 10 Worst	$20,793
Annual Volatility	13%


CO2 Emissions of Portfolios in 2007 Trends
Million Tons
12
11
10
9
8
7
6
5
4
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2007 Trends
B2 Energy
2007 BAU
High RPS Port
Low RPS Port
Transport Port
No DSM Port