

# Electric Analysis

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

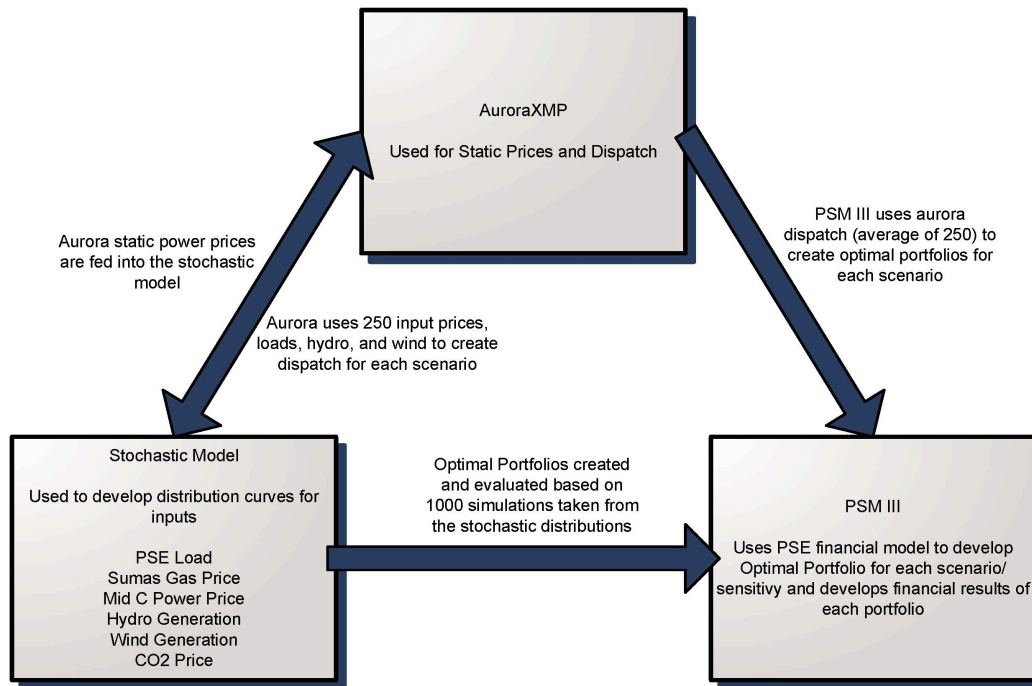
## ***1. Methods and Models***

### ***I. Methods***

#### *A. Diagram of Process for 2011 IRP*

PSE uses three models for electric integrated resource planning: AURORAxmp, a Stochastic Model, and the Portfolio Screening Model III (PSM III). AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch, as described later in this appendix. The stochastic model is used to create draws and distributions for various variables. PSM III creates optimal portfolios and 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.

**Figure I-1**  
**Electric Analysis Methodology**



## *B. Risk Analysis*

### **i. Scenarios**

A description of the scenarios and sensitivities can be found in Chapter 4. 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 4. The optimal portfolio for each scenario is the lowest-cost combination of supply and demand side resources that meets PSE's needs. More details on these portfolios can be found in section 2 of this appendix.

### iii. Probabilistic Analysis of Risk Factors

In addition to using scenarios to assess risk, this 2011 IRP continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling in PSM III. It relies on Monte Carlo simulations of six uncertainty factors: natural gas prices, power prices, CO2 prices, weather and economic-demographic 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 Stochastic model. This model and its assumptions are further described later in this appendix.

### iv. Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power Planning and Conservation Council (NWPCC) in its power plans. Additionally, PSE 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, to drive the electric energy market using the logic of a production costing model. 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.”<sup>1</sup>

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 percent. PSE tested capacity pool reserve margins at 0 percent, 5 percent, and 15 percent. A pool reserve margin of 15 percent best mitigated summer price spreads without increasing average prices unreasonably. Many U.S. regions plan for at least a 15 percent 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.

### *B. Stochastic Model*

#### **i. Overview**

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This requires developing stochastic inputs for the Portfolio Screening Model for risk simulation analysis, which then allows for the development of risk metrics to evaluate alternative portfolios. The stochastic modeling process used in this IRP consists of developing stochastic inputs using Monte Carlo analysis, using the Monte Carlo draws to generate a distribution of resource outputs (dispatched to prices and must take), costs and revenues from AuroraXMP, and utilizing these distributions to perform risk simulations in the PSMIII model for any given portfolio. The stochastic inputs considered in this IRP are MidC

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<sup>1</sup> EPIS, Inc., “Long-Term Studies Using Reserve Margins,” from AURORAxmp electronic documentation, December 2005.

power price, Sumas gas price, CO2 price (once it is introduced), PSE load, hydropower and wind generation. This section describes how PSE developed these stochastic inputs.

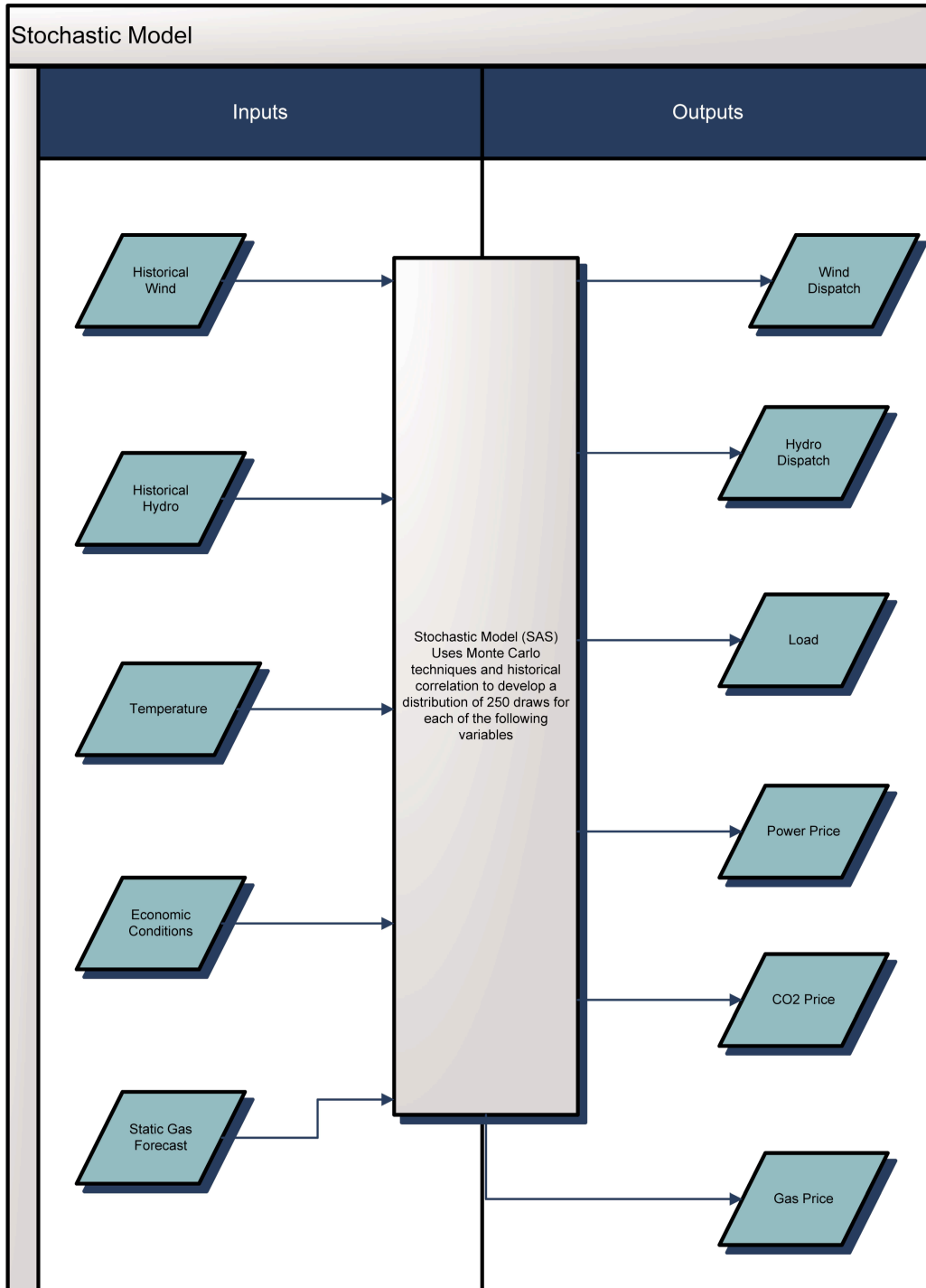
### **ii. Development of Monte Carlo Draws for the Stochastic Variables**

One important aspect in the development of the stochastic variables is the imposition of consistency across draws and key scenarios. This required ensuring, for example, that the same temperature conditions prevail for a load draw and for a power price draw. Figure I-2 shows the key drivers in developing these stochastic inputs. In essence, weather variables and long-term economic conditions determine the variability in the stochastic inputs. Furthermore, two distinct approaches were used to develop the 250 Monte Carlo draws for the inputs: a) loads and prices were developed using econometric analysis given their connection to weather variables (temperature and water conditions) and key economic assumptions, and b) hydro and wind variability were based directly on historical information.

The econometric equations estimated using regression analysis provide the best fit between the individual explanatory values and maximize the predictive value of each explanatory variable to the dependent variable. However, there exist several components of uncertainty in each equation, including: i) uncertainty in the coefficient estimate, ii) uncertainty in the residual error term, iii) the covariate relationship between the uncertainty in the coefficients and the residual error, and iv) uncertainty in the relationship between equations that are simultaneously estimated. Monte Carlo draws utilizing these econometric equations capture 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.

Figure I-2  
Stochastic Model Diagram



### PSE's Load Forecast

PSE developed a set of 250 Monte Carlo load forecast draws by allowing two sets of variable inputs to vary for each draw: 1) weather, and 2) economic-demographic conditions. The load forecast draws were created in three steps. First, PSE created 250 unique annual temperature profiles to use in the place of “normal” weather. Second, we created three separate long-term economic-demographic scenarios to use as the drivers of long-term growth. In the final step, for each of the 250 load forecast draws, a load scenario was created by selecting a unique weather pattern from the first step, plus an economic-demographic scenario selected probabilistically from the second step.

The 250 unique annual temperature profiles were created synthetically. For each temperature profile, an annual hourly temperature shape was selected randomly from the 60 years worth of hourly shapes at Sea-Tac Airport: 1950 to 2010. Each annual hourly temperature shape was adjusted in an additive process to fit an annual average temperature selected according to a probabilistic distribution of historical annual average temperatures, also from Sea-Tac: 1950-2010. By this process, PSE is able to create an infinite amount of unique temperature profiles to test possible load outcomes. For the current IRP, 250 annual temperature profiles were generated.

The three economic-demographic scenarios used in the analysis are the ones underlying the following load forecast scenarios: “2010 Base Case,” “2010 Structural Alternate Low,” and “2010 Structural Alternate High.” Information about the economic-demographic conditions forecast for these three scenarios is detailed in Appendix H. For the Monte Carlo draws, the following probabilities were assigned to the selection of economic scenarios: 80 percent Base Case, 10 percent Structural Low, 10 percent Structural High.

For each of the 250 Monte Carlo load forecast draws, a temperature profile was selected sequentially from the 250 pre-created weather scenarios detailed above, ensuring that each profile was used once and not repeated. For each draw, an economic scenario was selected according to the probabilities listed above. In each draw, the selected weather and economic inputs were used in the econometric load models to forecast a unique load scenario. For more details on the econometric load forecast models, see Appendix H.



### Gas and Power Prices

The econometric relationship between prices and their explanatory variables is shown in the two equations below:

Sumas Gas Price = f(US Gas Storage Deviation fr. 5 Yr Avg, Oil Price, Lagged Oil Price, Time Trend)

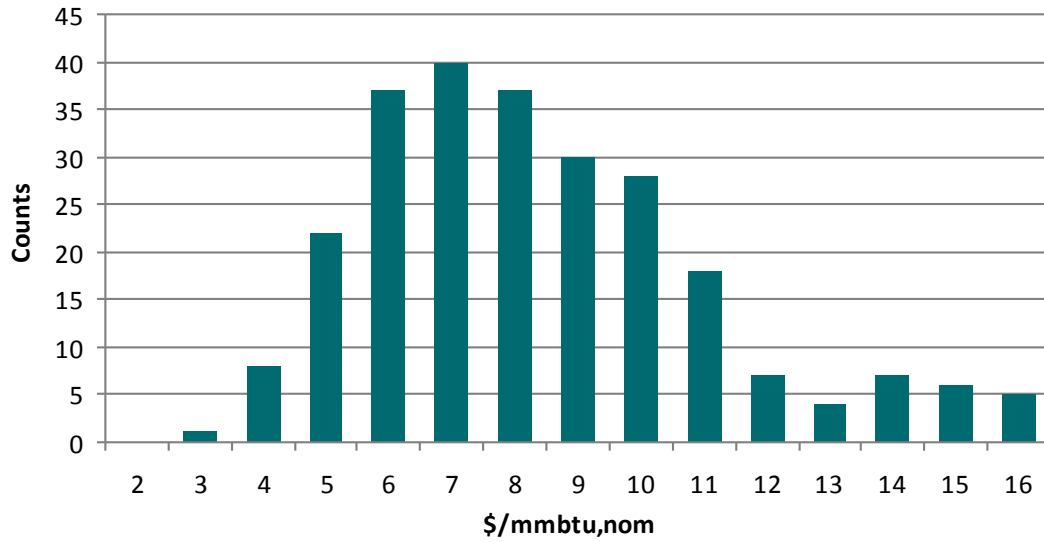
MidC Power Price = f(Sumas Gas Price, Regional Temperature Deviation from Normal, MidC Hydro Generation, Day of Week, Holidays)

A semi-log functional form is used for each equation. The two equations are estimated simultaneously with one period autocorrelation using historical daily data from January 2003 to August 2010.

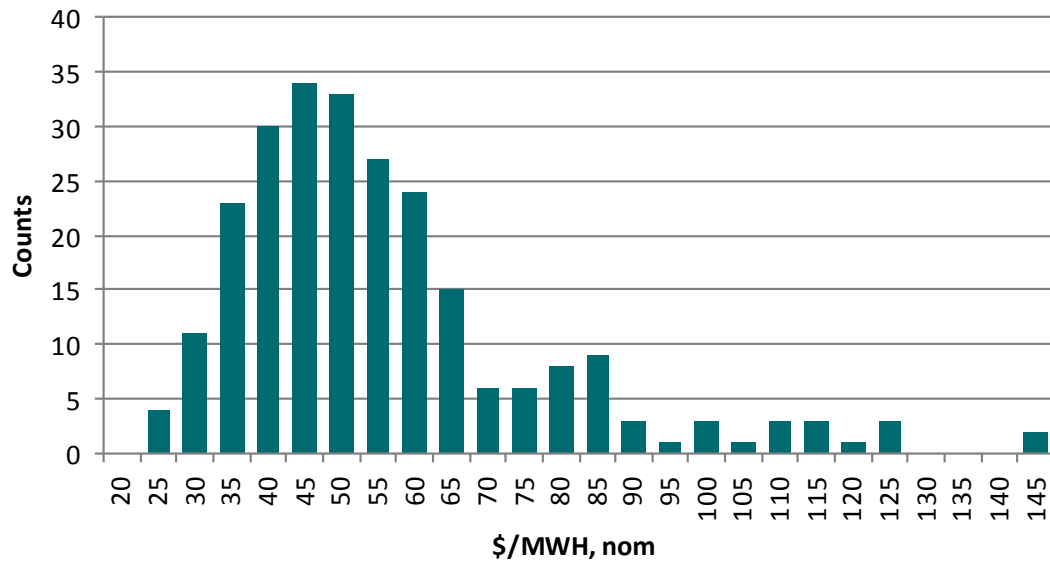
Monte Carlo draws were obtained based on the error distributions of the estimated equations, oil price draws, temperature draws, and hydro condition draws. The temperature draws are consistent with those drawn for the load forecast, while the hydro draws are consistent with those drawn directly from the 70-year historical hydro data as described below. Gas price draws were further adjusted so that the 5<sup>th</sup> percentile, 10<sup>th</sup> percentile, 90<sup>th</sup> percentile and 95<sup>th</sup> percentiles correspond to the very low, low, high and very high gas price scenarios, respectively, based on the rank levelized price of each draw. The price draws were calibrated to ensure that the means of adjusted distributions are equal to the base case prices. Hourly power prices were then obtained using the hourly shape for the base case from AuroraXMP.

Figures I-3 and I-4 show the monthly distribution of gas and power prices for January 2016. As expected, the distribution is skewed positively or right-skewed, implying that there is a higher probability of realizing high prices relative to the mean compared to low prices. The correlation coefficient between gas and power prices for the draws in January 2016 is .75.

**Figure I-3**  
**Monthly Sumas Gas Price Distribution – Jan. 2016**



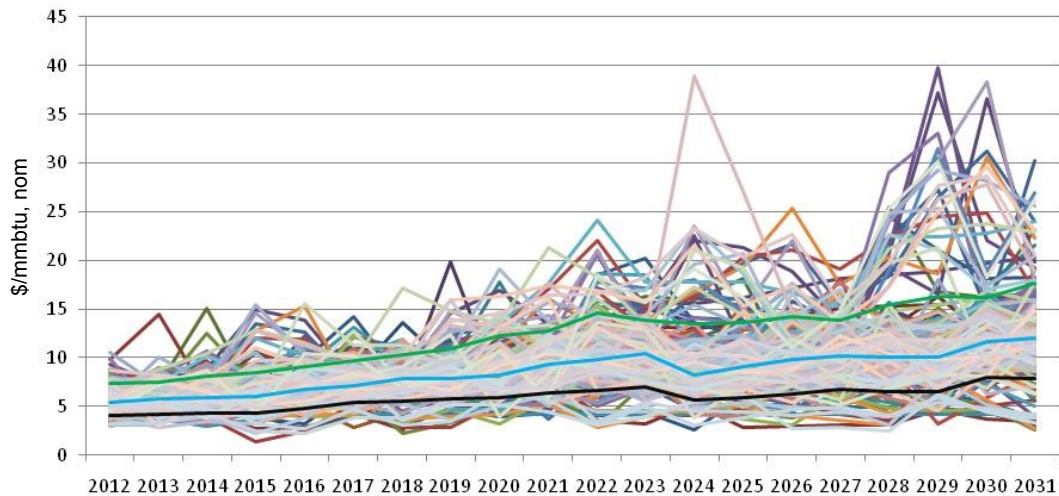
**Figure I-4**  
**Monthly Mid-C Power Price Distribution – Jan. 2016**



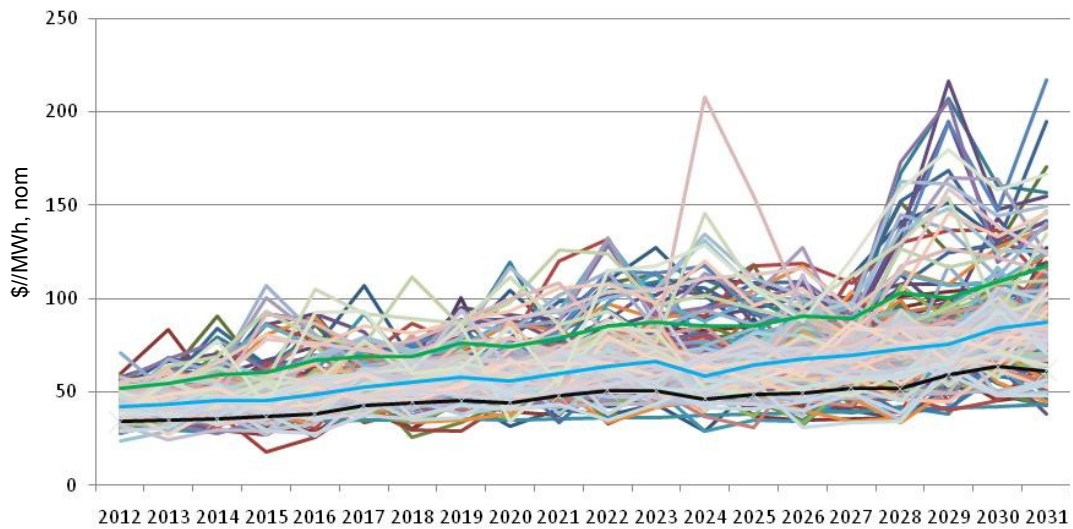
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The annual Sumas gas price and MidC power price draws are shown in Figures I-5 and I-6, respectively.

**Figure I-5**  
**Annual Sumas Price Draws**



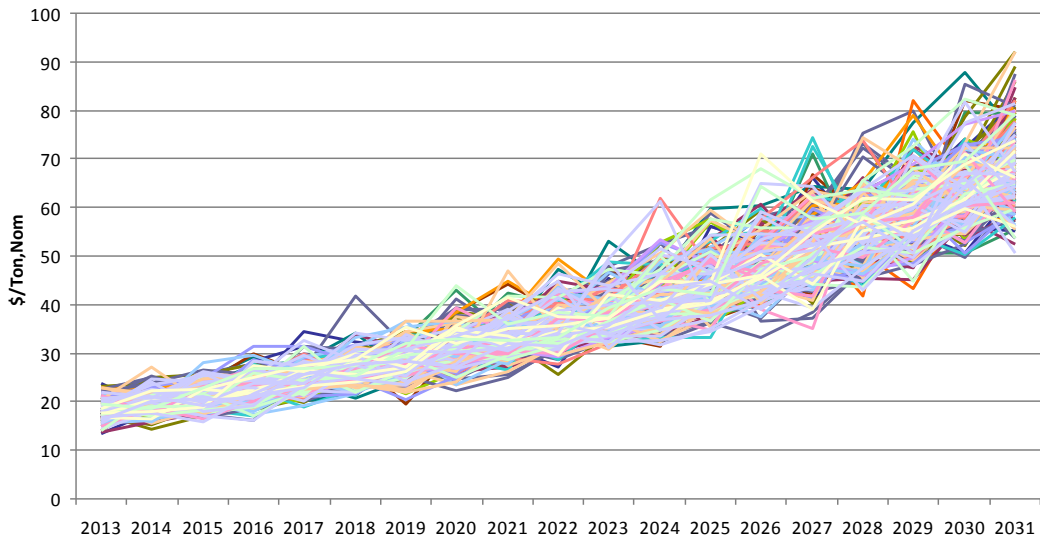
**Figure I-6**  
**Annual Mid-C Price Draws**



### CO2 Prices

Annual CO2 prices in nominal dollars per ton are assumed to follow the EPA study as described in Chapter 4. This implies that the annual price variation will be determined more by how much allowances are put out by the government and the overall macroeconomic conditions. However, given these average annual prices, monthly variations around the annual averages are assumed to vary with the market heat rate based on the gas and power price draws. When gas prices are low, there is less demand for allowances since generators will shift more from coal to gas fuels, and vice versa. Figure I-7 shows the annual CO2 price draws.

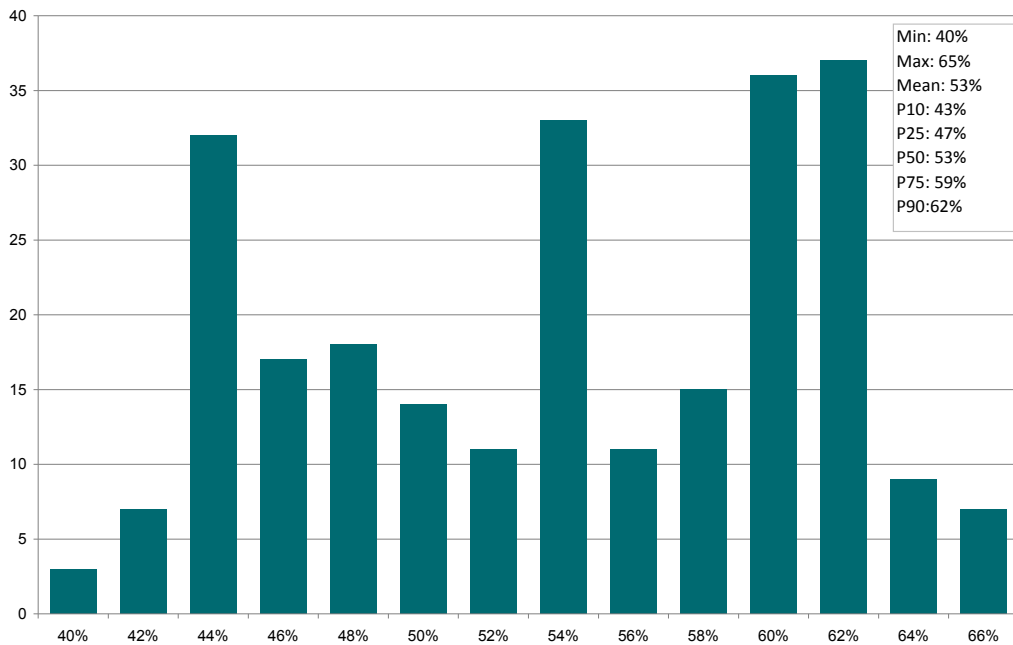
**Figure I-7**  
**Annual CO2 Price Draws**



## Hydro Generation

Monte Carlo draws for each of PSE’s hydro projects were obtained using the 70-year historical Pacific Northwest Coordination Agreement Hydro Regulation data published in 2010. Each hydro year is assumed to have an equal probability of being drawn in any given calendar year in the planning horizon. Capacity factors and monthly allocations are drawn as a set for each of the 250 draws. This set of 250 hydro draws is applied for each year in the planning horizon. Figure I-8 shows the frequency distribution of capacity factors for Wells based on the 250 draws.

**Figure I-8**  
**Frequency of Annual Hydro Capacity Factor for Wells**



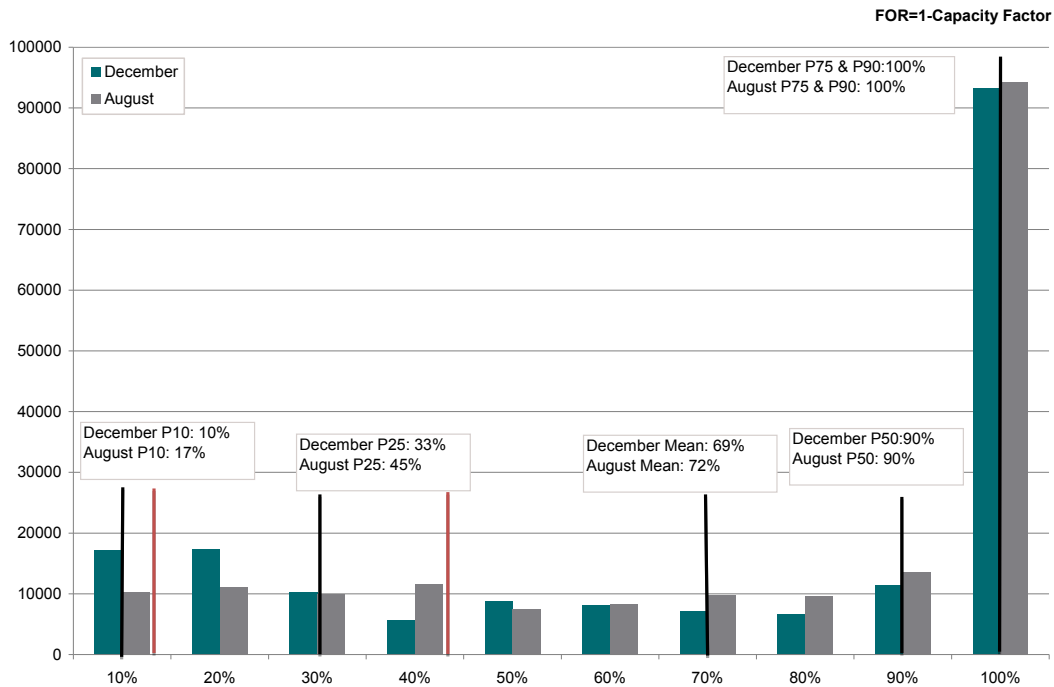
## Wind Generation

Since wind is an intermittent resource, one of the goals in developing the generation profile for each wind project considered in this IRP is to ensure that this intermittency is preserved. The other goals are to ensure that there could be correlations across wind

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farms and the seasonality of wind generation. The wind distributions were derived from 3.5 years of historical data from Hopkins Ridge and Wild Horse. Given the limited historical data that is available to generate the 250 hourly wind profiles, draws of daily 24-hour wind profiles are made each month with each day having an equal probability of being chosen until all days in the month are populated. Since draws for each month are based only on daily profiles within each month, the seasonality of wind generation is also preserved. Finally, draws across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse. The Lower Snake River wind farm, which has not been built yet, is assumed to have the same wind profile as Hopkins Ridge, with a lag since it is located near Hopkins Ridge, and scaled to its nameplate capacity and pro-forma capacity factor. Finally, the generic wind farm is assumed to have a wind profile distribution similar to that of Hopkins Ridge, scaled to a 100 MW capacity. Again, the same set of 250 draws is used for each of the calendar years in the planning horizon. Figure I-9 below shows the frequency distribution of hourly forced outage rate for the generic wind farm for August and December.

**Figure I-9**  
**Frequency of Hourly Forced Outage Rate for Generic Wind Farm**



### iii. Aurora Risk Modeling of PSE Portfolios

The advanced risk modeling capabilities of AuroraXMP are utilized to generate the variable costs, outputs and revenues of any given portfolio. The main advantage of using AuroraXMP 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 250 draws for all of the risk variables (power prices, gas prices, CO2 prices, PSE loads, hydro generation and wind generation) are fed into the AuroraXMP model. Given each of these input draws, AuroraXMP then dispatches PSE's existing portfolio and all generic resources to market price. The results are then saved and passed on to the PSMIII model where expected dispatch energy, expected costs, and revenues are utilized to obtain the optimal set of generic portfolio builds. Revenue requirements based on the expected energy outputs, costs, and revenues can then be computed for each set of portfolio generated by PSMIII.

### iv. Risk Simulation in PSM III

In order to perform risk simulation of any given portfolio in PSMIII, the distribution of the stochastic variables must be incorporated into the model. The base case 250 draws of dispatched outputs, costs and revenues for PSE's existing and generic resources were fed into PSMIII from AuroraXMP and the Stochastic Model as described above. Note that these AuroraXMP outputs have already incorporated the variability in gas and power prices, CO2 price, PSE's loads, hydro and wind generation from the Stochastic Model. Frontline System's Risk Solver Platform Excel Add-On allows for the automatic creation of distributions of energy outputs, costs, and revenues based on the 250 draws that PSMII can utilize for the simulation analysis. In addition, peak load distribution, consistent with the energy load distribution, was incorporated into the PSMII. Given these distributions, the risk simulation function in the Risk Solver Platform allowed for drawing 1,000 trials to obtain the expected present value of revenue requirements, TailVar90, and the volatility index for any given portfolio. In addition to computing the risk metrics for the present value of revenue requirements, risk metrics are also computed for annual revenue requirements and power costs. The results of the risk simulation are presented in Chapter 5.

### **C. Portfolio Screening Model III**

#### **i. Overview**

The risk model used for this IRP combines the strengths of the stochastic model 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 stochastic model, the Aurora model generates the variable costs of dispatched generation from existing/new resources and market purchases/sales for all 250 trials. These outputs are then averaged and the expected is 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.

#### **ii. Aurora Risk Modeling of PSE Portfolios**

The advanced 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 250 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 average of the 250 draws is then computed, and the expected results are saved and passed on to the portfolio screening model, where the model is optimized to find a portfolio based on a minimized expected revenue requirement. Expected costs and risk metrics can then be computed for each set of portfolio generated by the optimization.

#### **iii. Portfolio Screening Model**

The Portfolio Screening Model (PSM3 for version 3) is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. The model produces the optimal mix of resources that minimizes the present value of revenue requirements subject to planning margin and renewable portfolio standard constraints. Incremental cost includes: (i) the variable fuel cost and emissions for PSE's existing fleet, (ii) the variable



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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 resource dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM are:

- a) PSE's peak and energy demand forecasts,
- b) PSE's existing and generic resources, their capacities and outage rates,
- c) expected dispatched energy (MWh), variable cost (\$000) and revenue (\$000) from AURORAxmp for existing contracts, existing and generic resources,
- d) capital and fixed-cost assumptions of generic resources,
- e) financial assumptions such as cost of capital and escalation rates,
- f) capacity contributions and planning margin constraints,
- g) renewable portfolio targets.

### *Mathematical representation of PSM III*

The purpose of the programming model is to create an optimal mix of new generic resources that minimizes the 20-year net present value of the revenue requirement plus end effects (or total costs) given that the portfolio meets the planning reserve margin (PRM) and the renewable portfolio standard (RPS), and subject to other various non-negativity constraints for the decision variables. The decision variables are the annual integer number of units to add for each type of generic resources being considered in the model. We may add one or two more constraints later on. The revenue requirement is the incremental portfolio cost for the 20-year forecast.

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Let:

gn, gr – index for generic non-renewable and renewable resource at time t, respectively;

xn, xr – index for existing non-renewable and renewable resource at time t, respectively;

d(gn) – index for decision variable for generic non-renewable resource at time t;

d(gr) - index for decision variable for generic renewable resource at time t;

AnnCapCost = annual capital costs at time t for each type of resource (the components are defined more fully in the excel model);

VarCost = annual variable costs at time t for each type of resource (the components are defined more fully in the excel model);

EndEff = end effects at T, end of planning horizon, for each type of generic resource only (the components are defined more fully in the excel model);

ContractCost = annual cost of known power contracts;

DSRCost = annual costs of a given demand side resources;

NetMktCost = Market Purchases less market sales of power at time t;

RECSales = Sales of excess over RPS required renewable energy at time t

Cap = capacities of generic and existing resources;

PM = planning margin to be met each t;

MWH = energy production from any resource type gn,gx,xn,xr at time t;

RPS = percent RPS requirement at time t;

PkLd = expected peak load forecast for PSE at time t;

EnLd = forecasted Energy Load for PSE at generator without conservation at time t;

LnLs = line loss associated with transmission to meet load at meter;

DSR = demand side resource energy savings at time t;

r = discount rate.

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Annual revenue requirement (for any time t) is defined as:

$$RR_t = \sum_{gn} d(gn) * [AnnCapCost(gn) + VarCost(gn)] + \sum_{gr} d(gr) * [AnnCapCost(gr) + VarCost(gr)] + \sum_{xn} VarCost(xn) + \sum_{xr} VarCost(xr) + ContractCost + DSRCost + NetMktCost - RECSales.$$

- a) The objective function for the model is the present value of RR to be minimized. This function is non-linear with integer decision variables.

$$PVRR = \sum_{t=1}^T RR_t * [1/(1+r)^t] + [1/(1+r)^{20}] * [ \sum_{gn} d(gn) * EndEff(gn) + \sum_{gr} d(gr) * EndEff(gr) ].$$

- b) The objective function is subject to two constraints
- a. The planning margin was found using the loss of load probability (LOLP) approach. Details about the planning margin can be found later in this appendix. In the model, the planning margin of 15.7 percent is used as a lower bound on the constraint. That is, the model must minimize the objective function while maintaining a minimum of 15.7 percent capacity above the load in any given year. Below is the mathematical representation of how the planning margin is used as a constraint for the optimization.

$$\sum_{gn} d(gn) * Cap(gn) + \sum_{gr} d(gr) * Cap(gr) + \sum_{xr} Cap(xr) + \sum_{xn} Cap(xn) \geq PkLd + PM \text{ for all } t;$$

- b. PSE is subject to the Washington state renewable target as stated in RCW 19.285. The load input for PSM is the load at generator, so that the company generates enough power to account for line loss and still meet customer needs. The RPS target is set to the average of the previous two years' load at meter less DSR. The model must minimize the objective function while maintaining a minimum of the total RECs need to meet the state RPS. Below

is the mathematical representation of how the RPS is used as a constraint for the optimization.

$$\sum_{gr} d(gr)*MWH(gr) + \sum_{xr} MWH(xr) \geq RPS * \frac{\sum_{t=2}^{t-1} (EnLd * (1 - LnLs) - DSR)}{2} \text{ for all } t;$$

$d(gn)$ ,  $d(gr) \geq 0$ , and are integer values for all  $t$ ,

Other restrictions include total build limits. For example, only one biomass plant can be built a year for a total of four plants over the 20-year time horizon. For the generic wind, five plants may be built in a year, for a total of 10 plants over the 20-year time horizon.

The model is solved using Frontline System's Risk Solver Premium, software that provides various linear, quadratic and nonlinear programming solver engines in Excel environment. Frontline System is the developer of the Solver function that comes standard with Excel. The software solves this non-linear objective function typically in less than a minute. It also provides a simulation tool to calculate the expected costs and risk metrics for any given portfolio.

#### iv. Monte Carlo Draws for the Risk Simulation

PSE utilized the 250 draws from the stochastic model as the basis for the 1,000 simulated risk trials. For each of the 1,000 trials, a draw was chosen at random from the 250 draws and the revenue requirement for the portfolio was calculated using all the outputs associated with that draw (MidC power price, CO2 price, Sumas natural gas price, hydro generation, wind generation, and load).

## 2. Data

### 1. 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, Washington, Idaho and Montana, which combined have 12 areas. 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 2011 IRP, load forecasts for Oregon, Washington, Montana, and Idaho were based on the Northwest Power and Conservation Council (NPCC) 6<sup>th</sup> Power Plan load forecast. 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 2009.02 version produced in October 2009.

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically, an RPS state has a

specific percentage of energy consumed that must come from renewable resources by a certain date (e.g., 10 percent 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 2009 U.S. 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 70 historical years of 1929 to 1998. 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 2010, the PTC was scheduled to expire at the end of 2012. The reference

assumption is that PTCs remain at the current rate through 2012. PTCs are still assumed to be given to a project for 10 years after it is placed into service. As of 2013, 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 percent of the capital cost for solar and wind resources, and 10 percent of the capital cost for biomass and geothermal resources. Currently, the ITC is scheduled to expire at the end of 2012. This scenario assumes ITCs remain at the current rate through 2012.

### **iii. Treasury Grant**

The Treasury Grant (Grant) is a third federal subsidy available to qualifying renewable energy projects. This subsidy differs from the previous two in that it is a cash payment, vs. a tax credit, from the federal government. Currently, the Grant amounts to 30 percent of the eligible capital cost for renewable resources; it is scheduled to expire at the end of 2012. Through 2012, this scenario assumes the Grant remains at current levels. It is important to note that this is the financial incentive modeled in the 2011 IRP analysis. This simplifies the modeling, as the grant is not a function of taxable income.

### **iv. Renewable Portfolio Standard (WECC)**

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, PSE first identified the load forecast for each state in the model. Then the company identified the benchmarks of each RPS (e.g. 3 percent in 2015, then 15 percent 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,

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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 by technology type. These vary considerably. For example, Arizona has little wind potential, but great solar potential.

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.



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Figure I-10

### RPS Requirements for States in WECC

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 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.	The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only.

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State	Standard (LBNL)	Notes for AURORA Modeling
Montana	<p>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.</p> <p>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.</p>	<p>The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW.</p>
Nevada	<p>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.</p>	<p>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.</p>
New Mexico	<p>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.</p>	<p>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.</p>
Oregon	<p>Large utility targets: 5% in 2011, 15% in 2015, 20% in 2020 and 25% in 2025.</p> <p>Large utility sales represented 73% of total sales in 2002.</p> <p>Medium utilities 10% by 2025</p> <p>Small utilities 5% by 2025.</p>	
Washington	<p>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.</p>	

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### v. Renewable Portfolio Standard (PSE)

The current PSE resources that meet the Washington state RPS include Hopkins Ridge, Wild Horse, Klondike III, Snoqualmie Upgrades, Lower Snake River I, and Lower Baker Upgrades. The Washington state RPS also gives an extra 20 percent credit to renewable resources that use apprenticeship labor. That is, with the adder a resource can contribute 120 percent to RCW 19.285. The PSE resources that can claim the extra 20 percent are Wild Horse Expansion, Lower Snake River I and Lower Baker Upgrades. For modeling purposes, we assume that the generic wind receives the extra 20 percent.

#### C. Generic Resource Costs and Characteristics

Figure I-11

Generic Resource Costs and Characteristics

2010 \$	Units	CCCT	Peaker	Wind	Biomass	Transmission
Winter Capacity	MW	334	213	100	25	500
Capital Cost	\$/KW	\$1,540	\$1,010	\$2,151	\$4,330	\$436
O&M Fixed	\$/KW-yr	\$22.00	\$15.90	\$29.90	\$190.00	\$15.25
O&M Variable	\$/MWh	\$0.44	\$0.67	\$3.50	\$3.40	
Force Outage Rate	%	3%	3%		6.3%	
Wind Capacity Factor	%			30%		
Capacity Credit	%	93%	93%	1.8%	93%	100%
Heat Rate – GT	Btu/KWh	7,085	10,440		13,420	
Heat Rate – DF	Btu/KWh	9,350				
Fixed Gas Transport	\$/KW-yr	\$31.80	\$0.00			
Variable Gas Transport	\$/MWh	\$2.00	\$5.20			
Fixed Transmission	\$/KW-yr	\$0.00	\$0.00	\$34.30	\$18.01	
Variable Transmission	\$/MWh	\$0.00	\$0.00	\$3.30	\$1.71	
Water Consumption	Gallons/MWh	26				
Emissions:						
SO <sub>2</sub>	lbs/MMBtu	0.010	0.010			
NO <sub>x</sub>	lbs/MMBtu	0.007	0.009			
CO <sub>2</sub>	lbs/MMBtu	115.9	115.9			
Location		PSE Control	PSE Control	WA/OR	PSE Control	Mid-C to PSE
First Year Available		2014	2014	2014	2014	2017

The generic Combined Cycle Combustion Turbine (CCCT) is assumed to be a 1x1 facility with a dry air cooled condenser.

### *D. Financial Assumptions*

We used the pre-tax weighted average cost of capital (WACC) from the 2009 General Rate Case of 8.1 percent nominal or 6.89 percent after-tax. The REC price of \$8/MWh in 2012 was escalated at 2.5 percent.

### *E. Wind Capacity Credit*

#### **i. Methodology Used**

The wind capacity credits for PSE's existing and prospective wind farms were developed by applying the ELCC (equivalent load carrying capability) approach with our LOLP (loss of load probability) model. In essence, the ELCC approach identifies the equivalent capacity of a peaker plant that would yield the same loss of load probability as the capacity of a given wind farm. The ratio of the equivalent peaker capacity to the wind capacity is the ELCC or the capacity credit of the wind farm. Appendix I of the 2009 IRP provides a detailed description of the LOLP model. The basic idea of the LOLP model is to shock the electric system with Monte Carlo draws of hourly loads, forced outages, hydro conditions, and availability of transmission for market purchases to determine the percent of the time that a load is greater than resources over the number of iterations. This might require adding more resources in order to achieve the industry standard of five percent LOLP.

In order to implement the ELCC approach in the LOLP model, the distribution of wind hourly generation for each of the existing and prospective wind farms was developed. These are described in Appendix I, in the Stochastic Model portion of the Methods and Models section, under the Wind Generation subheading. Given these distributions, the wind farms were incrementally added into the LOLP model to determine the reduction in peaker capacity to achieve the 5 percent loss of load probability. The ratio of the change in peaker capacity with and without the incremental wind capacity is that wind farm's capacity credit. The order in which the existing and prospective wind farms were added in the model follows the schedule when these wind farms were acquired or about to be acquired by PSE: Wild Horse, Hopkins Ridge, Lower Snake River, then a generic wind

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resource expected to be located in southeast Washington close to the Lower Snake River project, or a generic wind resource located in Kittitas County close to the Wild Horse project.

### ii. Results

The figure below shows the results of the ELCC study.

**Figure I-12**  
**Effective Load Carrying Capability of Wind**

<b>Summary All Wind</b>	<b>Wind Capacity</b>	<b>Effective Thermal Capacity</b>	<b>ELCC</b>
Hopkins Ridge	157	23	14.8%
Wild Horse	272	39	14.5%
Lower Snake River	342	33	9.6%
Generic SE WA(w/Added Transmission)	100	2	1.8%
Generic Kittitas(w/Added Transmission)	100	5	4.9%

\* Wild Horse is supply only since it displaces existing transmission allocated for short-term market purchase.

These results indicate that wind power's contribution to capacity is not as significant as other resources, such as thermal power. Although the capacity contribution of existing wind facilities is higher than the regional assumption of 5 percent, subsequent wind farms are likely to show lower capacity contribution because of the correlation of wind outputs with pre-existing farms. This result is consistent with those found in earlier studies. While diversity may show different capacity credit, the differences in amounts are not significant. These results are highly dependent on PSE's resource mix, load characteristics, and projected distribution of wind profiles.

### *F. Planning Standard*

The company's planning standard is a 15.7 percent planning margin for capacity plus relevant operating reserves. PSE's planning margin is net of operating reserves. This is so the specific implications of different resource operating reserve requirements can be modeled independently. For example, peakers must carry 7 percent contingency

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reserves, but demand-side resources have none. Embedding operating reserves in the planning margin would not allow the company to reflect such differences in our analytical framework. This planning standard was adopted in the 2009 IRP. It is consistent with the NW Regional Resource Adequacy Forum<sup>2</sup> on the adoption of a Loss of Load Probability approach to planning that is common in other parts of the country. PSE values the NW Regional Resource Adequacy Forum's work on resource adequacy. It is the best assessment available in the region and PSE actively participates on both the steering committee and technical committee.

The following summarizes how the company derived the 15.7 percent planning margin standard:

The primary objective of PSE's capacity planning standard analysis was to determine the appropriate level of planning margin for the utility. Planning 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 margin is measured as:

$$\text{Planning Margin} = (\text{Generation Capacity} - \text{Normal Peak Loads}) / \text{Normal Peak Loads}$$

The appropriate level of planning 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

$$\text{LOLP} = \text{Probability} [-(\text{Generation Capacity} - \text{Loads}) > 0].$$

Thus, as the reserve margin increases, one would expect that the LOLP also decreases. 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.

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<sup>2</sup> 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>

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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 degree Fahrenheit, 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 1/70<sup>th</sup> probability;
4. Market Purchases – modeled as 50 percent from hydropower with same variability as Mid Columbia resources; 50 percent 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 percent for 60 percent of the trials, with a range of +/-3.5 percent.

As mentioned above, loss of load probability is defined as the number of trials where PSE 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 the utility 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.

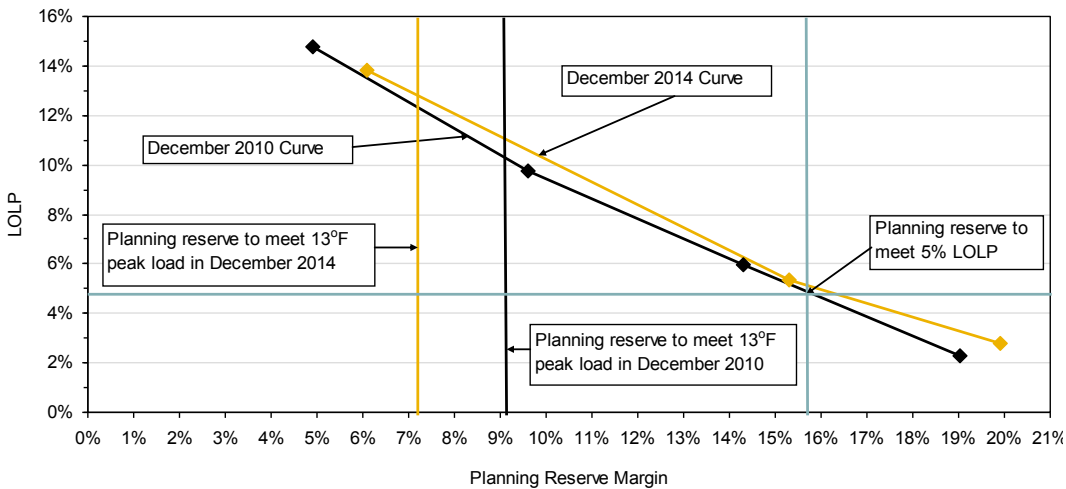
The goal of the simulation analysis for any hour is to run the simulation for the existing resource and load conditions, which imply an existing reserve margin. Loss of load probability associated with this reserve margin is then computed based on the 3,000 Monte Carlo draws of the risk variables. Generating capacity is then incremented using a

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combined-cycle plant as the “typical” plant added which results in a higher reserve margin. 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 I-13. The figure illustrates that the planning reserve margin implied by a 5 percent LOLP is around 15.7 percent for both years. The figure also demonstrates that the LOLP implied by meeting the 13 degrees Fahrenheit peak loads from the B2 Energy Planning Standard is much higher (10 percent for December 2010 and 13 percent for December 2014) if no additional resources are added. The 5 percent 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. PSE focused discussion on December because the company found that if we have resources adequate to meet the 5 percent LOLP in December, we will have resources sufficient to meet that reliability threshold during the rest of the year.

**Figure I-13**  
**Planning Margin and LOLP**





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## 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.

**Figure I-14**  
**Monthly Flat Mid-C Prices**  
**(Nominal \$/MWH)**

#### Base

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	44.76	47.59	40.87	35.77	31.49	32.60	40.71	43.06	45.59	44.68	52.64	50.30	42.51
2013	47.30	50.48	43.39	39.00	32.32	32.83	42.07	45.01	48.56	46.03	52.87	52.20	44.34
2014	49.14	52.01	44.41	39.32	32.62	33.74	44.01	47.04	51.13	48.66	57.18	56.55	46.32
2015	49.97	53.45	45.78	40.87	34.13	36.56	46.13	48.59	52.50	49.76	58.18	57.34	47.77
2016	53.65	56.98	49.10	44.15	35.68	38.67	49.18	52.51	55.69	51.51	62.25	59.26	50.72
2017	58.06	60.26	49.71	44.74	36.03	39.64	52.88	57.01	60.10	57.52	68.33	65.55	54.15
2018	61.94	65.31	52.74	46.38	35.81	38.37	55.71	61.46	64.83	59.54	68.74	68.16	56.58
2019	63.96	67.89	55.89	51.50	39.35	40.75	58.82	63.58	66.98	61.65	71.63	70.90	59.41
2020	65.80	65.64	51.37	44.88	31.03	36.65	58.57	64.70	69.60	64.52	74.88	73.29	58.41
2021	69.80	69.77	54.58	47.17	32.47	39.56	64.57	70.24	74.13	64.48	80.28	77.19	62.02
2022	74.11	75.24	61.54	56.06	38.04	45.27	68.13	75.93	78.65	69.03	85.79	81.19	67.42
2023	75.46	75.02	57.75	48.70	34.58	42.00	69.48	78.45	82.12	76.57	90.53	84.73	67.95
2024	70.32	72.37	55.53	48.85	35.71	37.30	65.62	71.73	75.64	67.31	78.33	77.05	62.98
2025	73.05	74.97	60.27	55.60	39.58	42.59	67.85	73.75	78.18	68.59	80.95	80.93	66.36
2026	76.89	78.25	60.28	51.89	36.49	42.91	71.85	78.43	84.30	76.69	89.39	87.71	69.59
2027	78.36	81.21	62.04	52.20	37.37	45.12	73.84	80.09	83.76	72.55	90.78	89.16	70.54
2028	82.68	86.50	69.16	61.11	45.68	53.52	77.94	84.55	86.80	77.55	97.40	93.60	76.37
2029	89.35	93.43	69.50	57.92	44.22	47.37	82.14	92.93	98.68	88.65	102.76	101.27	80.68
2030	97.01	99.74	73.16	62.22	48.08	50.68	88.97	97.70	103.22	88.97	107.90	107.80	85.54
2031	98.78	103.57	79.91	73.09	54.86	60.14	92.16	98.37	106.15	91.09	111.71	112.22	90.17

#### Base + CO<sub>2</sub>

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	43.22	46.30	41.14	35.71	31.40	32.60	40.52	42.68	45.34	44.55	52.31	48.80	42.05
2013	54.07	58.12	51.90	47.86	44.50	46.00	51.30	54.16	57.13	54.48	61.58	60.07	53.43
2014	56.48	60.65	54.29	50.10	46.77	47.99	53.71	56.85	60.49	57.01	66.40	63.78	56.21
2015	58.28	63.57	57.99	53.24	48.47	51.07	56.93	59.55	63.07	60.27	68.68	66.41	58.96
2016	62.10	67.26	60.27	55.14	51.39	53.52	59.63	63.01	66.26	63.82	73.71	71.28	62.28
2017	66.66	71.86	64.24	58.04	54.11	56.66	63.99	68.00	71.51	68.74	80.02	77.06	66.74
2018	71.39	77.50	68.89	62.08	55.82	58.29	68.20	73.02	76.75	73.47	82.56	81.13	70.76
2019	74.45	80.48	71.93	65.81	59.01	60.73	71.82	75.91	80.28	76.32	85.94	84.20	73.91
2020	77.28	81.75	72.55	65.74	57.11	59.90	74.30	78.45	83.37	78.84	90.80	87.94	75.67
2021	83.54	87.01	77.57	70.86	60.39	63.79	80.07	84.74	88.63	83.23	96.53	92.03	80.70
2022	89.06	91.33	84.00	78.46	63.44	67.52	84.75	91.31	93.97	87.79	101.64	95.34	85.72
2023	91.63	92.78	83.33	75.33	62.52	64.72	87.12	94.40	96.96	92.53	106.61	99.99	87.33
2024	89.50	94.70	84.04	75.63	61.24	61.21	86.84	93.01	96.30	90.63	100.18	97.68	85.91
2025	93.96	99.34	89.62	81.89	63.53	66.23	91.31	96.74	101.09	94.79	105.33	103.54	90.61
2026	99.01	105.05	91.96	81.99	65.77	68.66	96.14	103.07	108.46	101.86	114.47	111.57	95.67
2027	103.34	109.81	95.93	86.62	67.69	73.07	99.82	107.24	111.03	104.45	118.32	115.27	99.38
2028	109.28	115.94	103.72	93.58	75.31	83.07	105.32	112.73	114.86	110.55	125.41	120.75	105.88
2029	115.52	123.04	106.97	90.31	73.21	77.05	111.79	121.26	125.63	118.14	131.92	129.81	110.39
2030	123.64	130.68	111.97	97.82	77.49	82.35	120.42	127.17	131.26	123.26	138.28	136.58	116.74
2031	129.19	139.96	120.49	108.15	82.25	91.18	127.67	132.55	138.03	129.57	145.95	145.64	124.22

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## Load Growth

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	33.58	36.59	32.95	29.21	27.17	28.44	32.34	33.98	36.09	35.24	41.58	39.58	33.90
2013	35.89	38.27	34.31	31.09	27.69	28.13	33.36	35.34	37.81	36.21	41.90	40.79	35.07
2014	38.42	40.67	35.84	32.14	28.42	29.43	35.72	37.76	41.02	38.66	45.43	44.26	37.31
2015	40.45	43.49	38.14	34.27	30.19	32.03	38.14	40.05	43.25	41.56	48.41	46.35	39.69
2016	41.50	44.66	39.33	35.63	29.46	31.69	38.73	41.11	44.15	42.20	49.82	46.87	40.43
2017	43.04	45.28	39.46	35.34	29.29	31.72	40.14	42.86	46.01	44.13	52.84	49.63	41.65
2018	44.22	47.31	40.52	35.97	29.11	29.47	40.88	44.09	47.42	43.98	51.64	49.12	41.98
2019	45.29	48.26	41.89	38.17	30.11	30.70	41.85	44.63	48.29	44.92	52.42	50.22	43.06
2020	45.05	46.05	39.27	34.48	25.28	26.97	40.97	44.37	48.24	44.68	53.12	50.50	41.58
2021	45.66	46.88	40.08	34.63	25.07	27.27	41.71	45.08	48.12	43.84	53.28	50.03	41.80
2022	45.55	47.05	42.52	38.31	27.21	29.40	42.06	46.37	49.64	45.04	55.00	49.72	43.16
2023	46.73	47.03	40.38	34.76	24.71	26.47	42.41	47.68	50.62	47.57	57.29	52.21	43.16
2024	48.33	49.57	42.00	36.93	24.72	24.52	43.60	48.93	52.89	48.10	55.25	51.78	43.89
2025	49.68	50.80	44.58	40.34	25.25	27.08	44.31	49.39	53.85	48.70	56.31	53.27	45.30
2026	51.12	52.29	42.56	37.67	21.80	26.66	45.02	51.36	56.82	52.20	60.15	56.93	46.22
2027	52.27	53.60	43.67	37.92	21.23	27.04	45.37	52.36	56.88	51.15	60.69	57.07	46.60
2028	53.03	55.06	46.92	40.77	24.62	29.48	46.06	53.66	57.57	52.19	62.66	57.80	48.32
2029	54.88	56.64	46.27	38.61	21.99	25.12	46.76	55.67	61.63	56.45	63.82	60.78	49.05
2030	58.81	59.79	46.22	39.48	22.39	25.25	49.13	57.32	62.03	56.66	65.84	63.52	50.54
2031	58.14	61.49	53.33	48.60	27.33	33.17	51.66	59.36	65.12	59.69	69.18	64.22	54.27

## High Growth

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	50.77	52.32	45.51	39.11	33.39	34.69	45.24	48.16	51.13	49.95	58.24	55.61	47.01
2013	56.91	58.88	51.36	44.90	36.71	36.50	50.11	53.65	58.07	54.69	62.20	61.65	52.14
2014	61.68	63.92	52.81	46.95	36.76	38.16	54.53	58.43	64.10	60.14	69.55	69.58	56.38
2015	68.70	71.84	58.66	52.41	40.39	43.11	61.03	65.31	70.52	66.12	76.93	76.61	62.64
2016	75.62	79.73	66.12	58.91	44.70	48.56	66.83	72.78	77.48	72.22	85.89	85.01	69.49
2017	75.05	77.52	61.09	54.29	42.17	46.64	66.65	72.83	77.89	73.53	86.49	85.30	68.29
2018	74.41	78.17	61.11	53.03	40.62	42.20	65.98	72.85	77.80	70.69	82.16	82.49	66.79
2019	80.14	83.66	66.77	61.23	45.55	46.60	72.39	78.52	83.62	74.74	88.06	88.27	72.46
2020	83.06	82.90	61.34	53.61	34.61	42.35	74.25	82.15	89.40	79.08	94.48	94.12	72.61
2021	84.45	83.95	63.45	53.70	33.83	43.68	76.04	83.62	88.77	74.40	94.71	94.25	72.90
2022	85.62	87.95	68.94	61.55	39.93	49.57	77.14	86.41	91.04	77.39	99.02	97.21	76.81
2023	95.97	92.98	69.12	57.47	38.14	48.52	85.64	97.00	104.05	93.87	114.53	110.11	83.95
2024	96.87	97.89	69.73	59.29	39.26	44.96	86.15	96.46	102.90	85.75	104.52	107.09	82.57
2025	97.57	98.98	74.71	66.33	43.02	51.14	87.44	95.63	103.96	85.31	107.36	109.11	85.05
2026	104.13	103.61	73.41	60.51	38.54	53.22	92.56	102.29	114.51	100.18	122.14	120.86	90.50
2027	109.69	110.19	78.34	63.96	42.11	57.90	97.49	107.05	116.13	94.81	126.31	125.17	94.10
2028	112.63	116.03	88.25	76.94	56.73	67.32	100.70	111.26	118.13	100.42	133.19	129.59	100.93
2029	117.04	119.61	84.55	68.90	52.37	59.14	104.06	118.87	128.99	114.51	136.69	136.19	103.41
2030	123.11	124.78	86.89	70.74	55.59	62.27	110.67	120.85	130.90	109.24	138.51	138.80	106.03
2031	131.91	139.52	108.65	97.19	76.12	81.24	117.34	128.53	138.20	121.49	146.00	149.45	119.64

## Green World

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	49.41	51.03	44.78	38.61	32.93	34.39	44.92	47.43	50.32	48.98	57.09	54.65	46.21
2013	73.38	77.50	71.95	66.33	62.29	62.98	70.63	73.84	77.58	74.15	81.07	79.66	72.61
2014	77.35	82.59	76.28	70.49	65.79	67.07	75.19	78.37	83.01	78.87	88.09	86.01	77.43
2015	85.47	89.85	83.66	77.12	72.01	74.31	82.84	85.92	90.16	87.20	95.82	93.57	84.83
2016	90.41	95.61	88.32	82.43	76.99	80.39	87.73	91.93	95.71	92.45	104.57	100.30	90.57
2017	92.80	96.97	89.71	82.97	77.37	81.65	89.41	94.03	97.96	94.80	106.81	103.08	92.30
2018	94.60	101.44	93.76	85.85	75.60	80.03	92.02	96.52	100.91	97.13	105.50	103.22	93.88
2019	100.68	107.48	99.52	92.54	82.47	85.55	97.87	102.50	107.25	103.14	112.57	109.77	100.11
2020	106.86	111.36	102.82	92.90	73.62	77.06	101.34	106.77	113.14	108.14	120.43	115.98	102.53
2021	112.17	117.61	107.50	94.00	72.62	79.21	106.31	111.88	118.04	113.93	125.59	120.39	106.60
2022	118.11	123.45	115.56	105.86	79.70	85.91	111.73	118.29	124.24	119.84	132.06	126.03	113.40
2023	129.34	132.70	120.05	104.55	80.43	82.88	121.30	128.05	135.87	131.12	146.13	138.89	120.94
2024	133.71	138.71	124.67	109.10	80.40	74.02	123.08	132.28	140.64	134.36	145.42	141.25	123.14
2025	140.79	146.02	134.43	119.72	80.04	82.54	127.17	137.19	147.34	140.42	152.56	148.76	129.75
2026	148.54	154.30	129.74	100.98	69.09	75.76	134.45	145.06	156.69	150.12	163.43	159.66	132.32
2027	157.89	163.68	134.37	114.76	69.24	78.69	141.81	153.71	164.36	155.60	173.40	168.67	139.68
2028	165.66	170.88	147.76	129.40	84.09	87.71	145.37	158.91	168.39	162.53	179.58	174.05	147.86
2029	170.10	178.93	137.96	100.35	61.22	67.12	146.97	168.24	178.46	168.37	185.38	182.08	145.43
2030	178.60	184.42	135.59	106.77	62.83	67.61	153.98	174.94	184.64	171.53	192.06	191.29	150.36
2031	185.90	196.61	172.13	152.46	82.09	87.25	165.25	182.46	193.54	182.61	203.75	201.20	167.10

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## Very High Gas

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	49.89	51.79	45.45	39.14	33.92	34.95	45.27	48.03	50.67	49.09	57.61	54.55	46.70
2013	57.19	59.73	51.61	46.67	37.21	37.13	50.91	54.96	58.47	55.35	62.65	61.86	52.81
2014	63.85	66.33	55.30	49.17	37.95	39.79	57.16	61.71	66.39	62.21	71.71	71.44	58.58
2015	74.16	76.83	62.37	55.31	41.71	45.57	65.56	70.96	74.99	70.68	81.28	80.95	66.70
2016	82.25	84.72	70.33	61.10	47.34	51.47	72.56	79.35	82.75	77.59	91.24	89.88	74.22
2017	82.29	83.68	63.71	56.83	42.88	48.71	73.24	80.34	84.46	80.13	93.97	91.72	73.50
2018	82.88	85.07	65.30	56.94	41.19	45.00	73.32	81.21	85.54	77.68	90.43	90.66	72.94
2019	89.31	92.04	71.86	65.97	47.95	49.66	79.32	86.46	91.34	82.41	96.16	96.62	79.09
2020	90.93	85.49	64.44	53.50	33.69	44.14	78.66	88.29	96.15	87.96	102.52	100.61	77.20
2021	95.15	90.14	66.74	54.86	36.20	46.37	82.19	90.49	96.42	82.15	104.11	103.06	78.99
2022	95.37	95.46	75.74	67.23	41.99	52.83	84.33	94.48	99.17	84.74	109.29	105.52	83.85
2023	108.45	100.21	73.63	57.86	40.30	51.41	93.81	107.71	114.92	106.90	127.51	120.22	91.91
2024	109.32	104.36	75.17	61.92	40.81	45.90	95.77	107.23	113.85	95.35	116.85	115.70	90.19
2025	109.44	107.30	82.35	73.45	46.67	55.40	97.49	107.95	116.11	97.14	119.95	120.91	94.51
2026	117.38	111.35	79.00	63.07	39.77	55.30	106.37	119.40	130.91	117.19	138.98	134.95	101.14
2027	118.19	113.37	81.08	62.37	38.69	57.88	109.38	120.82	128.54	104.06	138.44	132.96	100.48
2028	121.72	121.26	94.17	79.39	50.79	67.95	113.15	124.18	128.47	108.51	143.83	135.96	107.45
2029	124.79	123.84	83.57	64.68	41.58	52.76	114.61	131.89	142.63	124.95	146.41	142.68	107.87
2030	129.73	126.83	84.49	67.62	43.62	54.98	121.21	132.12	140.81	114.57	143.52	142.54	108.50
2031	134.85	134.50	99.71	87.12	53.50	69.51	125.44	135.85	147.66	119.62	149.90	151.26	117.41

## Very Low Gas

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	34.51	36.52	32.79	29.15	27.31	28.47	32.37	34.11	36.19	35.17	41.73	39.35	33.97
2013	34.65	37.07	33.25	30.32	27.52	27.88	32.47	34.50	36.90	35.27	40.45	39.15	34.12
2014	34.74	37.35	33.34	29.94	27.34	28.06	32.79	34.88	37.72	35.59	42.02	40.46	34.52
2015	35.69	38.78	34.69	30.84	28.08	29.38	33.68	35.64	38.18	36.85	41.97	40.79	35.38
2016	34.36	37.14	33.43	30.29	27.39	28.53	32.67	34.74	37.28	35.65	41.84	39.63	34.41
2017	34.99	38.38	33.72	29.88	27.17	28.70	33.02	35.43	37.62	36.70	44.03	41.51	35.10
2018	35.39	39.31	34.38	30.31	26.94	27.35	33.22	35.88	38.22	36.91	42.38	41.12	35.12
2019	35.46	39.68	34.34	30.47	27.12	27.26	33.55	35.91	38.79	37.16	43.17	41.53	35.37
2020	34.94	38.81	33.60	29.36	24.83	25.67	33.10	35.18	39.02	36.85	44.02	42.04	34.79
2021	35.61	39.85	34.10	29.86	25.07	26.45	33.66	35.80	39.45	37.27	44.46	42.21	35.32
2022	35.71	40.23	34.75	30.31	26.57	27.11	33.66	36.42	39.64	38.01	45.25	42.29	35.83
2023	36.70	40.94	34.95	29.95	25.49	26.51	34.36	37.16	40.60	39.57	46.99	43.99	36.43
2024	38.45	43.24	36.45	31.06	25.94	25.04	35.21	38.07	41.71	40.00	46.43	44.45	37.17
2025	38.78	44.05	37.40	31.44	26.89	26.65	35.71	38.26	42.32	40.37	47.41	45.94	37.94
2026	39.76	44.76	37.33	30.92	25.49	26.14	36.49	39.21	43.44	41.29	49.28	47.80	38.49
2027	41.18	47.02	38.29	31.36	26.04	27.49	37.38	40.39	44.33	41.80	50.90	48.88	39.59
2028	42.25	47.69	39.11	32.36	27.89	29.18	37.84	41.59	44.88	42.94	51.99	49.65	40.61
2029	43.54	49.55	40.21	32.06	27.32	27.08	38.56	43.66	47.25	44.02	52.58	51.50	41.44
2030	44.70	50.29	40.46	32.75	27.55	27.18	39.43	43.88	47.69	44.13	52.48	51.54	41.84
2031	45.84	51.43	41.85	34.39	28.47	29.32	40.43	44.44	49.02	45.08	53.51	53.02	43.07

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### B. Electric Demand-Side Screening Results

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

**Figure I-15**

#### Annual Energy Savings (aMW)

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

	Bundle									
	A	B	C	D	E	F	G	H	DE	EISA
2012	27.5	32.5	36.4	38.0	39.0	40.8	41.6	50.1	1.1	4.1
2013	56.1	67.0	74.9	78.1	80.3	83.9	85.5	102.9	2.2	11.9
2014	82.7	100.1	112.2	117.1	120.6	126.1	128.5	155.1	3.4	22.6
2015	107.8	132.7	149.0	155.7	160.8	168.2	171.5	207.6	4.5	31.7
2016	132.2	165.5	186.1	194.6	201.9	211.3	215.4	261.4	5.7	39.6
2017	155.2	197.4	222.3	232.6	242.5	253.8	258.8	314.6	7.2	46.1
2018	178.9	230.6	260.1	272.2	284.7	298.0	303.9	369.8	8.8	51.8
2019	203.1	266.0	300.8	315.0	330.1	345.5	352.3	428.6	10.3	56.5
2020	227.8	298.3	338.6	354.9	372.8	390.3	398.0	485.4	12.0	77.6
2021	251.3	328.5	374.1	392.4	412.9	432.5	441.1	539.1	13.6	95.3
2022	258.5	339.0	386.3	405.3	427.5	447.5	456.2	557.7	15.7	111.1
2023	265.9	349.7	398.7	418.4	442.3	462.7	471.6	576.8	17.9	125.1
2024	274.2	361.8	412.8	433.4	459.1	480.1	489.1	598.2	20.1	137.6
2025	280.7	371.4	424.1	445.4	472.7	494.0	503.2	616.0	22.3	147.3
2026	288.3	382.4	437.0	459.0	488.2	509.9	519.2	636.6	24.6	155.7
2027	295.7	393.2	449.7	472.4	503.1	525.3	534.8	656.6	27.0	162.7
2028	304.1	405.1	463.5	487.0	519.1	541.9	551.5	678.1	29.6	169.6
2029	311.1	415.2	475.5	499.7	532.7	555.9	565.7	696.3	31.9	174.9
2030	319.1	426.8	489.0	514.1	548.0	571.7	581.6	716.9	34.4	180.3
2031	327.0	438.2	502.3	528.2	563.0	587.2	597.3	737.2	36.8	185.5

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**Figure I-16**

**Total December Peak Reduction (MW)**

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

	Bundle										
	A	B	C	D	E	F	G	H	DE	EISA	DR
2012	37	49	56	59	61	63	64	77	2	5	10
2013	75	99	115	120	124	128	130	157	4	16	20
2014	110	149	172	180	186	192	195	237	5	30	30
2015	144	197	228	240	248	256	260	317	7	42	49
2016	176	246	286	300	312	322	327	400	9	52	50
2017	206	294	342	359	375	387	392	482	11	61	51
2018	237	342	398	419	437	451	458	564	14	68	75
2019	268	392	457	482	504	520	527	649	16	74	90
2020	300	439	514	542	567	586	594	734	19	102	127
2021	319	467	549	578	607	626	635	787	21	121	144
2022	342	501	589	621	652	673	683	847	25	146	162
2023	350	513	604	637	670	692	701	872	28	165	165
2024	358	525	617	651	685	708	717	894	32	181	169
2025	367	539	634	668	705	727	737	921	35	194	172
2026	377	554	652	688	726	749	759	952	39	205	175
2027	388	570	672	709	749	773	783	986	43	215	179
2028	397	584	688	726	767	792	802	1013	46	223	182
2029	405	597	704	742	785	810	820	1039	50	231	185
2030	414	610	720	759	803	829	839	1065	55	238	189
2031	424	626	738	779	823	850	860	1096	58	245	193

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday.

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Figure I-17

### Annual Costs (Thousands \$)

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

	Bundle										
	A	B	C	D	E	F	G	H	DE	EISA	DR
2012	\$29,160	\$58,001	\$85,232	\$100,108	\$110,522	\$130,716	\$140,619	\$612,534	\$1,184	\$0	\$8,839
2013	\$30,105	\$62,458	\$90,733	\$106,239	\$116,837	\$137,504	\$147,585	\$640,565	\$1,184	\$0	\$9,680
2014	\$30,862	\$66,407	\$95,589	\$111,582	\$122,339	\$143,429	\$153,652	\$664,289	\$1,184	\$0	\$10,078
2015	\$31,268	\$70,914	\$100,770	\$117,167	\$128,088	\$149,599	\$159,941	\$686,937	\$1,184	\$0	\$17,698
2016	\$31,813	\$76,031	\$106,677	\$123,416	\$134,511	\$156,456	\$166,898	\$709,821	\$1,184	\$0	\$4,301
2017	\$32,306	\$79,869	\$111,280	\$128,286	\$139,563	\$161,942	\$172,466	\$731,104	\$2,002	\$0	\$4,376
2018	\$32,754	\$82,686	\$114,798	\$132,004	\$143,464	\$166,272	\$176,851	\$750,660	\$2,002	\$0	\$30,166
2019	\$33,657	\$94,223	\$132,473	\$151,449	\$163,334	\$187,145	\$198,361	\$795,614	\$2,002	\$0	\$11,651
2020	\$34,186	\$73,849	\$113,370	\$132,735	\$144,891	\$169,237	\$180,610	\$793,174	\$2,002	\$0	\$42,737
2021	\$34,449	\$73,202	\$112,554	\$132,044	\$144,407	\$168,841	\$180,192	\$806,499	\$2,002	\$0	\$16,283
2022	\$9,940	\$29,082	\$43,407	\$49,621	\$52,157	\$57,244	\$59,308	\$279,141	\$2,537	\$0	\$18,112
2023	\$10,200	\$29,183	\$43,824	\$50,086	\$52,843	\$58,079	\$60,182	\$292,652	\$2,537	\$0	\$14,714
2024	\$10,486	\$29,412	\$44,391	\$50,747	\$53,732	\$59,134	\$61,279	\$307,334	\$2,537	\$0	\$14,953
2025	\$10,714	\$29,635	\$44,895	\$51,382	\$54,480	\$60,015	\$62,194	\$318,708	\$2,537	\$0	\$15,192
2026	\$10,966	\$29,946	\$45,486	\$52,146	\$55,351	\$61,031	\$63,243	\$330,688	\$2,537	\$0	\$15,434
2027	\$11,240	\$30,358	\$46,162	\$53,037	\$56,341	\$62,178	\$64,422	\$342,605	\$2,678	\$0	\$15,679
2028	\$11,468	\$30,896	\$46,937	\$54,064	\$57,455	\$63,446	\$65,714	\$352,867	\$2,678	\$0	\$15,923
2029	\$11,736	\$31,631	\$47,923	\$55,357	\$58,840	\$65,032	\$67,335	\$364,341	\$2,678	\$0	\$16,194
2030	\$12,002	\$32,627	\$49,111	\$56,875	\$60,431	\$66,813	\$69,139	\$375,724	\$2,678	\$0	\$16,459
2031	\$12,278	\$33,502	\$50,112	\$58,245	\$61,863	\$68,444	\$70,788	\$387,273	\$2,678	\$0	\$16,730

### C. Electric Integrated Portfolio Results

This chart summarizes the expected costs of the different portfolios.

Figure I-18

### Revenue Requirements with Expected Inputs for the Scenario

Scenario	20-yr NPV Expected Cost (\$Millions)						Expected Portfolio Cost \$/MWh
	Expected Portfolio Cost	Net Purchases/ (Sales)	DSR Rev. Req.	Generic Rev. Req.	Variable Cost of Existing	REC Revenue	
Base	\$13,365	\$5,207	\$1,262	\$3,913	\$3,035	(\$52)	\$46.72
Base + CO2	\$15,928	\$5,210	\$1,262	\$4,647	\$4,861	(\$51)	\$55.68
Low Growth	\$9,826	\$2,283	\$1,262	\$3,282	\$3,057	(\$56)	\$36.17
High Growth	\$18,582	\$7,435	\$1,262	\$5,900	\$4,057	(\$71)	\$61.66
Very Low Gas	\$10,870	\$2,016	\$767	\$5,076	\$3,061	(\$50)	\$37.70
Very High Gas	\$16,455	\$6,749	\$1,262	\$4,605	\$3,917	(\$78)	\$57.51
Green World	\$21,065	\$6,847	\$1,513	\$5,412	\$7,534	(\$242)	\$77.54
<b>PTC Sensitivity</b>							
Base + PTC/ITC Extension 2013	\$13,331	\$5,025	\$1,262	\$4,102	\$3,035	(\$94)	\$46.60
Base + PTC/ITC Extension 2016	\$13,271	\$5,044	\$1,262	\$4,018	\$3,035	(\$88)	\$46.39
Base + PTC/ITC Extension 2020	\$13,241	\$5,120	\$1,262	\$3,896	\$3,035	(\$72)	\$46.29
Base + PTC/ITC Extension 2031	\$13,236	\$5,175	\$1,262	\$3,823	\$3,035	(\$59)	\$46.27
<b>Risk Sensitivity</b>							
Base + Fixed Gas Transport	\$14,103	\$5,195	\$1,262	\$4,664	\$3,035	(\$53)	\$49.30
Base + No Peakers	\$14,539	\$2,796	\$1,262	\$7,507	\$3,035	(\$60)	\$50.83
Base + Thermal Mix	\$14,259	\$3,130	\$1,262	\$6,702	\$3,035	(\$50)	\$49.85
Base + No DSR	\$16,071	\$6,842	\$0	\$6,239	\$3,035	(\$45)	\$56.18

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**Figure I-19**

### Revenue Requirement with Input Simulations – 1000 Trials

20-yr NPV Portfolio Cost (\$Millions)	Risk Simulation - 1000 Trials			
	Base	Base + Thermal Mix	Base + No Peaker	Base + No DSR
Expected	\$13,365	\$14,259	\$14,539	\$16,071
Minimum	\$9,235	\$9,699	\$9,993	\$10,592
1st Quartile (P25)	\$12,402	\$13,218	\$13,428	\$14,987
Mean	\$13,349	\$14,209	\$14,448	\$16,045
Median	\$13,122	\$14,062	\$14,346	\$15,794
3rd Quartile (P75)	\$13,712	\$14,746	\$15,021	\$16,474
TVar90	\$17,902	\$18,411	\$18,525	\$21,433
Maximum	\$20,508	\$21,168	\$21,348	\$24,237
Standard Deviation	\$1,850	\$1,801	\$1,787	\$2,182
Annual Volatility	18.1%	17.4%	17.1%	18.5%

**Figure I-20**

### Base

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	25	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	100	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	213	-	25	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>400</b>	<b>50</b>	<b>500</b>	<b>1126</b>	<b>193</b>

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**Figure I-21**  
**Base + CO<sub>2</sub>**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	100	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	100	-	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>500</b>	<b>0</b>	<b>500</b>	<b>1126</b>	<b>193</b>

**Figure I-22**  
**Low Growth**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	852	-	-	-	78	10
2015	-	-	-	25	-	76	19
2016	-	-	-	25	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	-	200	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	-	-	-	-	35	3
2025	-	-	100	-	-	36	3
2026	-	213	-	-	-	36	3
2027	-	-	-	-	-	36	3
2028	-	213	-	-	-	30	3
2029	-	-	-	-	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>1491</b>	<b>300</b>	<b>50</b>	<b>500</b>	<b>1126</b>	<b>193</b>



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**Figure I-23**  
**High Growth**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	25	-	78	10
2015	-	213	-	25	-	76	19
2016	-	-	-	25	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	25	-	75	16
2020	-	213	200	-	-	94	36
2021	-	213	-	-	-	66	17
2022	-	-	200	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	213	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	-	-	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>3195</b>	<b>400</b>	<b>100</b>	<b>500</b>	<b>1126</b>	<b>193</b>

**Figure I-24**  
**Green World**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	70	10
2013	-	-	-	-	-	77	10
2014	-	852	-	-	-	80	10
2015	-	-	500	-	-	78	19
2016	-	-	500	-	-	78	1
2017	-	-	-	-	500	76	1
2018	-	-	-	-	-	75	23
2019	-	-	-	-	-	77	16
2020	-	-	-	-	-	96	36
2021	-	-	-	-	-	67	17
2022	-	-	-	-	-	71	18
2023	-	213	-	-	-	40	3
2024	-	-	-	-	-	36	3
2025	-	-	-	-	-	37	3
2026	-	213	-	-	-	37	3
2027	-	-	-	-	-	36	3
2028	-	-	-	-	-	31	3
2029	-	213	-	-	-	30	4
2030	-	-	-	-	-	30	4
2031	-	-	-	-	-	32	4
<b>Total</b>	<b>0</b>	<b>1491</b>	<b>1000</b>	<b>0</b>	<b>500</b>	<b>1153</b>	<b>193</b>

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**Figure I-25**  
**Very Low Gas**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	56	10
2013	-	-	-	-	-	63	10
2014	-	1,065	-	-	-	65	10
2015	-	-	-	-	-	62	19
2016	-	213	-	-	-	61	1
2017	-	-	-	-	500	59	1
2018	-	-	-	-	-	58	23
2019	-	-	-	-	-	59	16
2020	-	213	300	-	-	77	36
2021	-	-	100	-	-	54	17
2022	-	-	-	-	-	58	18
2023	-	213	-	-	-	35	3
2024	-	213	-	-	-	31	3
2025	-	-	-	-	-	31	3
2026	-	-	-	-	-	30	3
2027	-	213	100	-	-	29	3
2028	-	-	-	-	-	25	3
2029	-	426	-	-	-	25	4
2030	-	-	100	-	-	25	4
2031	-	-	-	-	-	26	4
<b>Total</b>	<b>0</b>	<b>2556</b>	<b>600</b>	<b>0</b>	<b>500</b>	<b>929</b>	<b>193</b>

**Figure I-26**  
**Very High Gas**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	25	-	78	10
2015	-	-	-	25	-	76	19
2016	-	-	-	25	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	25	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	100	-	-	94	36
2021	-	-	200	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	-	-	-	-	35	3
2025	-	213	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	213	-	-	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>300</b>	<b>100</b>	<b>500</b>	<b>1126</b>	<b>193</b>

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Figure I-27

### Base + Fixed Gas Transport

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	25	-	40	3
2024	-	-	-	25	-	35	3
2025	-	213	-	25	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	100	-	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>400</b>	<b>75</b>	<b>500</b>	<b>1126</b>	<b>193</b>

Figure I-28

### Base + No Peaker

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	71	10
2013	-	-	-	-	-	78	10
2014	1,002	-	-	-	-	81	10
2015	-	-	-	25	-	79	19
2016	-	-	-	25	-	79	1
2017	-	-	-	-	500	77	1
2018	-	-	-	-	-	76	23
2019	-	-	-	-	-	78	16
2020	334	-	300	-	-	97	36
2021	-	-	-	-	-	68	17
2022	-	-	-	-	-	71	18
2023	334	-	-	-	-	40	3
2024	-	-	-	-	-	36	3
2025	-	-	-	-	-	37	3
2026	334	-	-	-	-	37	3
2027	-	-	100	-	-	36	3
2028	-	-	-	-	-	31	3
2029	334	-	-	-	-	30	4
2030	-	-	-	-	-	30	4
2031	-	-	-	-	-	32	4
<b>Total</b>	<b>2338</b>	<b>0</b>	<b>400</b>	<b>50</b>	<b>500</b>	<b>1163</b>	<b>193</b>

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Figure I-29

### Base + Thermal Mix

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	668	426	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	334	213	-	-	-	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	-	-	94	36
2021	-	-	-	-	-	66	17
2022	334	-	-	-	-	69	18
2023	-	-	-	-	-	40	3
2024	-	-	-	-	-	35	3
2025	-	-	-	25	-	36	3
2026	-	213	-	-	-	36	3
2027	-	-	100	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	-	-	25	500	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>1336</b>	<b>1065</b>	<b>400</b>	<b>50</b>	<b>500</b>	<b>1126</b>	<b>193</b>

Figure I-30

### Base + PTC/ITC Extension 2013

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	300	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	-	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	100	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	100	-	-	29	4
2030	-	-	-	25	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>500</b>	<b>25</b>	<b>500</b>	<b>1126</b>	<b>193</b>

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**Figure I-31**

**Base + PTC/ITC Extension 2016**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	400	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	-	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	-	25	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	100	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>500</b>	<b>25</b>	<b>500</b>	<b>1126</b>	<b>193</b>

**Figure I-32**

**Base + PTC/ITC Extension 2020**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	500	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	-	-	-	29	4
2030	-	-	-	25	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>500</b>	<b>25</b>	<b>500</b>	<b>1126</b>	<b>193</b>

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**Figure I-33**  
**Base + PTC/ITC Extension 2031**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	25	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	100	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	213	-	25	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
<b>Total</b>	<b>0</b>	<b>2343</b>	<b>400</b>	<b>50</b>	<b>500</b>	<b>1126</b>	<b>193</b>

**Figure I-34**  
**Base + No DSR**

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	1,278	-	-	-	-	-
2015	-	213	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	500	-	-
2018	-	213	-	-	-	-	-
2019	-	213	-	-	-	-	-
2020	-	213	400	25	-	-	-
2021	-	213	-	25	-	-	-
2022	-	-	-	25	-	-	-
2023	-	213	-	-	-	-	-
2024	-	213	100	-	-	-	-
2025	-	-	-	-	-	-	-
2026	-	213	-	-	-	-	-
2027	-	213	100	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	426	100	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	213	-	-	-	-	-
<b>Total</b>	<b>0</b>	<b>3834</b>	<b>700</b>	<b>75</b>	<b>500</b>	<b>0</b>	<b>0</b>

### *D. Incremental Cost of Renewable Resources to meet RCW 19.285 Incremental Cost Alternative Compliance*

#### **1. Overview**

According to RCW 19.285, certain electric utilities in Washington must meet 15 percent of their retail electric load with eligible renewable resources by the calendar year 2020. The annual target for the calendar year 2012 is 3 percent of retail electric load. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility will be considered in compliance with the annual renewable energy target in RCW 19.285. “The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that do not qualify as eligible renewable resources”<sup>3</sup> (equivalent non-renewable).

#### **2. Analytic Framework**

This analysis compares the revenue requirement cost of each renewable resource with the projected market value and capacity value at the time of the renewable acquisition. This, “contemporaneous” with the decision-making aspect of PSE’s approach, is important. Utilities should be able to assess whether they will exceed the cost cap before an acquisition, without having to worry about ex-post adjustments that could change compliance status. The analytical framework here reflects a close approximation of the portfolio analysis used by PSE in resource planning, as well as in the evaluation of bids received in response to the company’s Request for Proposals (RFP).

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<sup>3</sup> RCW 19.285.050 (1) (a) (b)

**3. Resources that meet RCW 19.285 definition of Eligible Renewable Resource**

**Figure I-35**

**Resources that meet RCW 19.285 definition of Eligible Renewable Resource**

	Nameplate (MW)	Annual Energy (aMW)	Commercial Online Date	Market Price/Peaker Assumptions	Capacity Credit Assumption
<b>Hopkins Ridge</b>	149.4	53.3	Dec 2005	2004 RFP	20%
<b>Wild Horse</b>	228.6	73.4	Dec 2006	2006 RFP	17.2%
<b>Klondike III</b>	50	18.0	Dec 2007	2006 RFP	15.6%
<b>Hopkins Infill</b>	7.2	2.4	Dec 2007	2007 IRP	20%
<b>Wild Horse Expansion</b>	44	10.5	Dec 2009	2007 IRP	15%
<b>Lower Snake River I</b>	342.7	102.5	Apr 2012	2010 Trends	5%
<b>Snoqualmie Upgrades</b>	6.1	3.9	Mar 2013	2009 Trends	95%
<b>Lower Baker Upgrades</b>	30	12.5	May 2013	2011 IRP Base	95%
<b>Generic Wind 2020</b>	300	89.7	Jan 2020	2011 IRP Base	1.8%
<b>Generic Wind 2027</b>	100	29.9	Jan 2027	2011 IRP Base	1.8%
<b>Generic Biomass 2020</b>	25	21.25	Jan 2020	2011 IRP Base	93%
<b>Generic Biomass 2029</b>	25	21.25	Jan 2029	2011 IRP Base	93%

**4. Equivalent Non-Renewable**

The incremental cost of a renewable resource is defined as the difference between the levelized cost of the renewable resource compared to an equivalent non-renewable resource. An equivalent non-renewable is an energy resource that does not meet the definition of a renewable resource in RCW 19.285, but is equal to a renewable resource on an energy and capacity basis. For the purpose of this analysis, the cost of an equivalent non-renewable resource has three components:

1. Capacity Cost: There are two parts of capacity cost: First is the capacity in MW. This would be nameplate for a firm resource like biomass, or the assumed capacity of a wind plant. Second is the \$/kW cost, which we assumed to be equal to the cost of a peaker.
2. Energy Cost: This was calculated by taking the hourly generation shape of the resource, multiplied by the market price in each hour. This is the equivalent cost of purchasing the equivalent energy on the market.



3. Imputed Debt: The law states the non-renewable must be an “equivalent amount,” which includes a time dimension. If PSE entered into a long-term contract for energy, there would be an element of imputed debt. Therefore, it is included in this analysis as a cost for the non-renewable equivalent.

For example, Hopkins Ridge produces 466,900 MWh annually. The equivalent non-renewable is to purchase 466,900 MWh from the Mid-C market and then build a 30 MW (149.4\*20 percent = 30) peaker plant for capacity only. With the example, the cost comparison includes the hourly Mid-C price plus the cost of building a peaker, plus the cost of the imputed debt. The total revenue requirement (fixed and variable costs) of the non-renewable is the cost stream—including end-effects—discounted back to the first year. That net present value is then levelized over the life of the comparison renewable resource.

### **5. Cost of Renewable Resource**

Levelized cost of the renewable resource is more direct. It is based on the preforma financial analysis performed at the time of the acquisition. The stream of revenue requirement (all fixed and variable costs, including integration costs) are discounted back to the first year—again, including end effects. That net present value is then levelized out over the life of the resource/contract. The levelized cost of the renewable resource is then compared with the levelized cost of the equivalent non-renewable resource to calculate the incremental cost.

**6. Example**

The following is a detailed example of how PSE calculated the incremental cost of Wild Horse. It is important to note that PSE's approach uses information contemporaneous with the decision making process, so this analysis will not reflect updated assumptions for capacity, capital cost, or integration costs, etc.

Eligible Renewable: Wild Horse Wind Facility

Capacity Contribution Assumption:  $228.6 * 17.2\% = 39 \text{ MW}$

1. Calculate Wild Horse Revenue Requirement

Figure I-36 is a sample of the annual revenue requirement calculations for the first few years of Wild Horse, along with the NPV of revenue requirement.

**Figure I-36**  
**Calculation of Wild Horse Revenue Requirement**

(\$ Millions)	20-yr NPV	2007	2008	...	2025
Gross Plant		384	384	...	384
Accumulative depreciation (Avg.)		(10)	(29)	...	(355)
Accumulative deferred tax (EOP)		(20)	(56)	...	(7)
Rate base		354	299	...	22
After tax WACC		7.01%	7.01%	...	7.01%
After tax return		25	21	...	2
Grossed up return		38	32	...	2
PTC grossed up		(20)	(20)	...	-
Expenses		16	16	...	22
Book depreciation		19	19	...	19
Revenue required	370.9	53	48	...	44
End effects	4.6				
Total revenue requirement	375				

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### 2. Calculate Revenue Requirement for Equivalent non-renewable: Peaker Capacity

Capacity = 39 MW

Capital Cost of Capacity: \$462/KW

**Figure I-37**

#### Calculation of Peaker Revenue Requirement

(\$ Millions)	20-yr NPV	2007	2008	...	2025
Gross Plant		18	18	...	18
Accumulative depreciation (Avg.)		(0)	(1)	...	(10)
Accumulative deferred tax (EOP)		(0)	(0)	...	(3)
Rate base		18	17	...	5
After tax WACC		7.01%	7.01%	...	7.01%
After tax return		1	1	...	0
Grossed up return		2	2	...	0
Expenses		1	1	...	2
Book depreciation		1	1	...	1
Revenue required	32	4	4	...	3
End effects	2				
Total revenue requirement	34				

### 3. Calculate Revenue Requirement for Equivalent non-renewable: Energy

Energy: 642,814 MWh

For the Market purchase, we used the hourly power prices from the 2006 RFP plus a transmission adder of \$1.65/MWh in 2007 and escalated at 2.5 percent.

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Month	Day	Hour	20-yr NPV	2007	...	2025
1	1	1		49 MW * \$59/MW = \$2891	...	49 MW * \$61/MW = \$2989
1	1	2		92 MW * \$60/MW = \$5520	...	92 MW * \$63/MW = \$5796
...	....	...		...	...	...
12	31	24		13 MW * \$59/MW = \$767	...	13 MW * \$65/MW = \$845
<b>(\$Millions)</b>						
<b>Cost of Market</b>				36	...	41
<b>Imputed Debt</b>				1	...	0
<b>Total Revenue Requirement</b>			285	37	...	41

**Figure I-38**  
**Calculation of Energy Revenue Requirement**

#### 4. Incremental Cost

The table below is the total cost of Wild Horse less the cost of the peaker and less the cost of the market purchases for the total 20-year incremental cost difference of the renewable to an equivalent non-renewable.

**Figure I-39**  
**20-yr Incremental Cost of Wild Horse**

(\$ Millions)	20-yr NPV
<b>Wild Horse</b>	375
<b>Peaker</b>	34
<b>Market</b>	285
<b>20-yr Incremental Cost of Wild Horse</b>	56

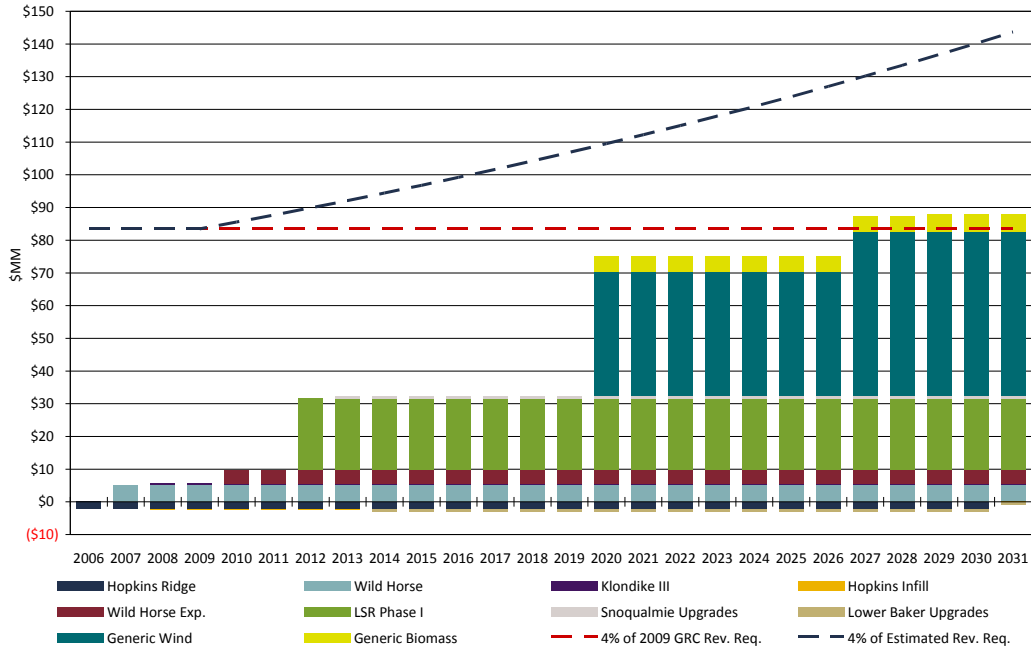
We chose to spread the incremental cost over 25 years since that is the depreciable life of a wind project used by PSE. The payment of \$56 Million over 25 years comes to \$5.2 Million/Year using the 7.01 percent discount rate.

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## 7. Summary Results

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power, and 40 years for hydroelectric power. Figure I-40 presents results of this analysis for existing resources and projected resources. This demonstrates PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. The negative cost difference means that the renewable was lower-cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

**Figure I-40**  
**Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4 Percent of 2009 GRC Revenue Requirement**



As the chart reveals, even if the company’s revenue requirement were to stay the same for the next 10 years, PSE would still not hit the 4 percent requirement. The estimated revenue requirement uses a 2.5 percent assumed escalation from the 2009 General Rate Case revenue requirement.