N

2017 PSE Integrated Resource Plan

Electric Analysis

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

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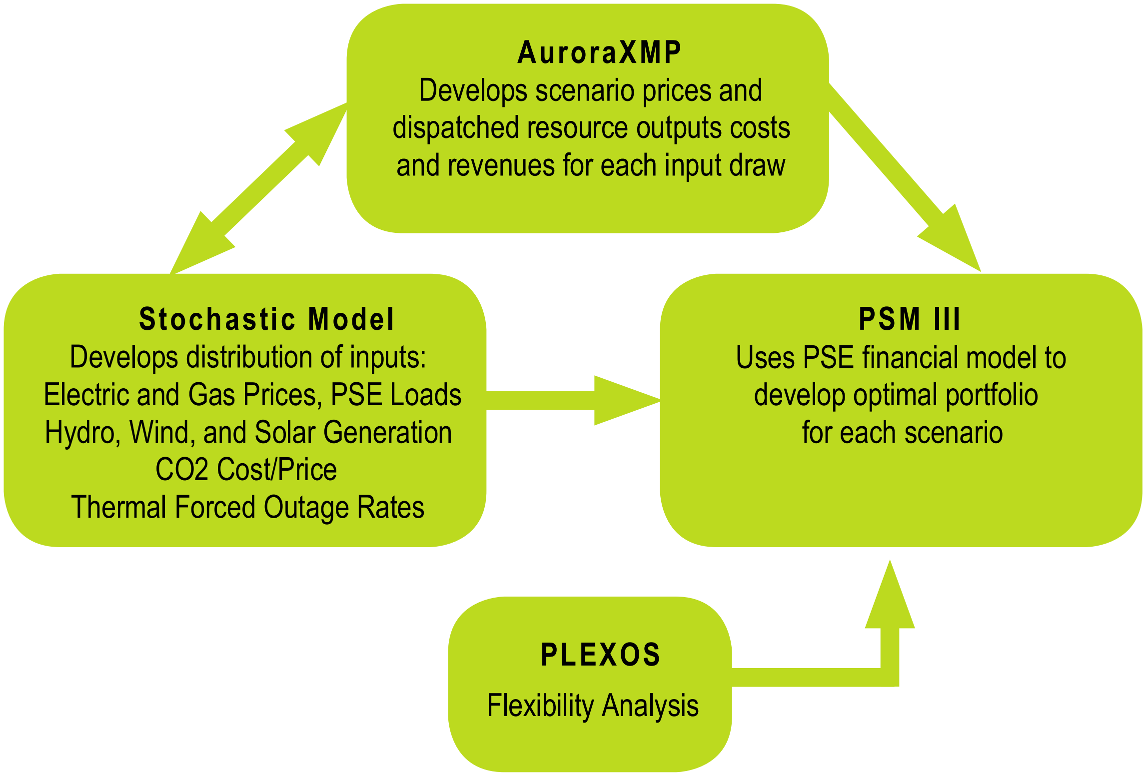
1. PORTFOLIO ANALYSIS METHODS

PSE uses four models for electric integrated resource planning: AURORAxmp,® PLEXOS, the Portfolio Screening Model III (PSM III), and a stochastic model. AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch. PLEXOS estimates the cost savings due to sub-hour operation for new generic resources. 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 stochastic model is used to create simulations and distributions for various variables. The following diagram shows the methods used to quantitatively evaluate the lowest reasonable cost portfolio.

Figure N-1 demonstrates how the four models are connected. The following steps are used to get to the least-cost portfolio for each of the scenarios and sensitivities.

1. Create Mid-C power prices in AURORAxmp for each of the 14 scenarios.
2. Using the Base Scenario Mid-C prices from AURORA, run the flexibility analysis in PLEXOS to find the flexibility benefit for each of the generic supply-side resources.
3. Using the Mid-C price, dispatch PSE's resources to market for each scenario.
4. The plant dispatch and the flexibility benefit are then input into PSM III to create an optimal portfolio for each of the 14 scenarios and 13 sensitivities.
5. Develop stochastic variables around power prices, gas prices, CO_2 prices, hydro generation, wind generation, PSE loads and thermal plant forced outages.

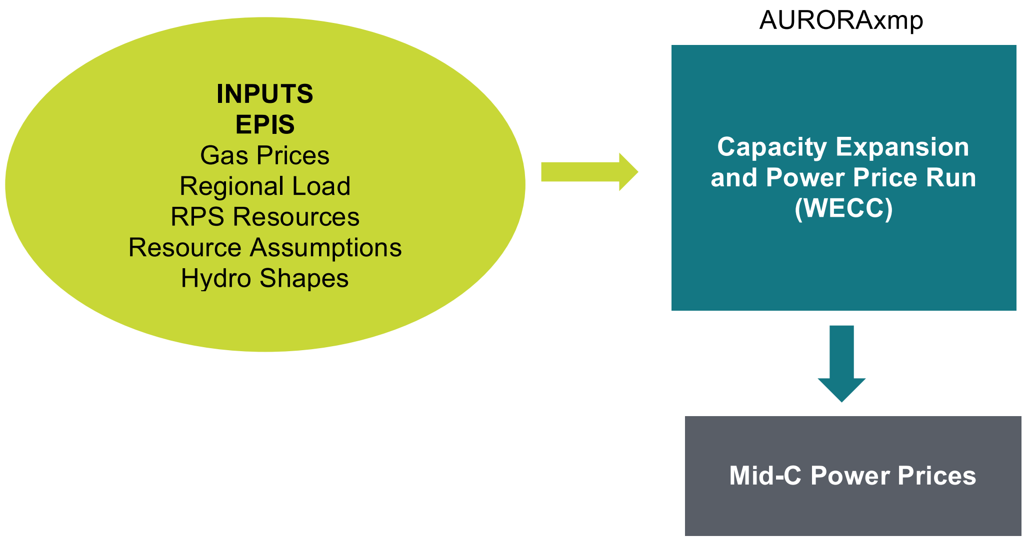
Figure N-1: Electric Analysis Methodology



Developing Wholesale Power Prices

Figure N-2 illustrates PSE's process for creating wholesale market prices in AURORA.

Figure N-2: PSE IRP Modeling Process for AURORA Wholesale Power Prices

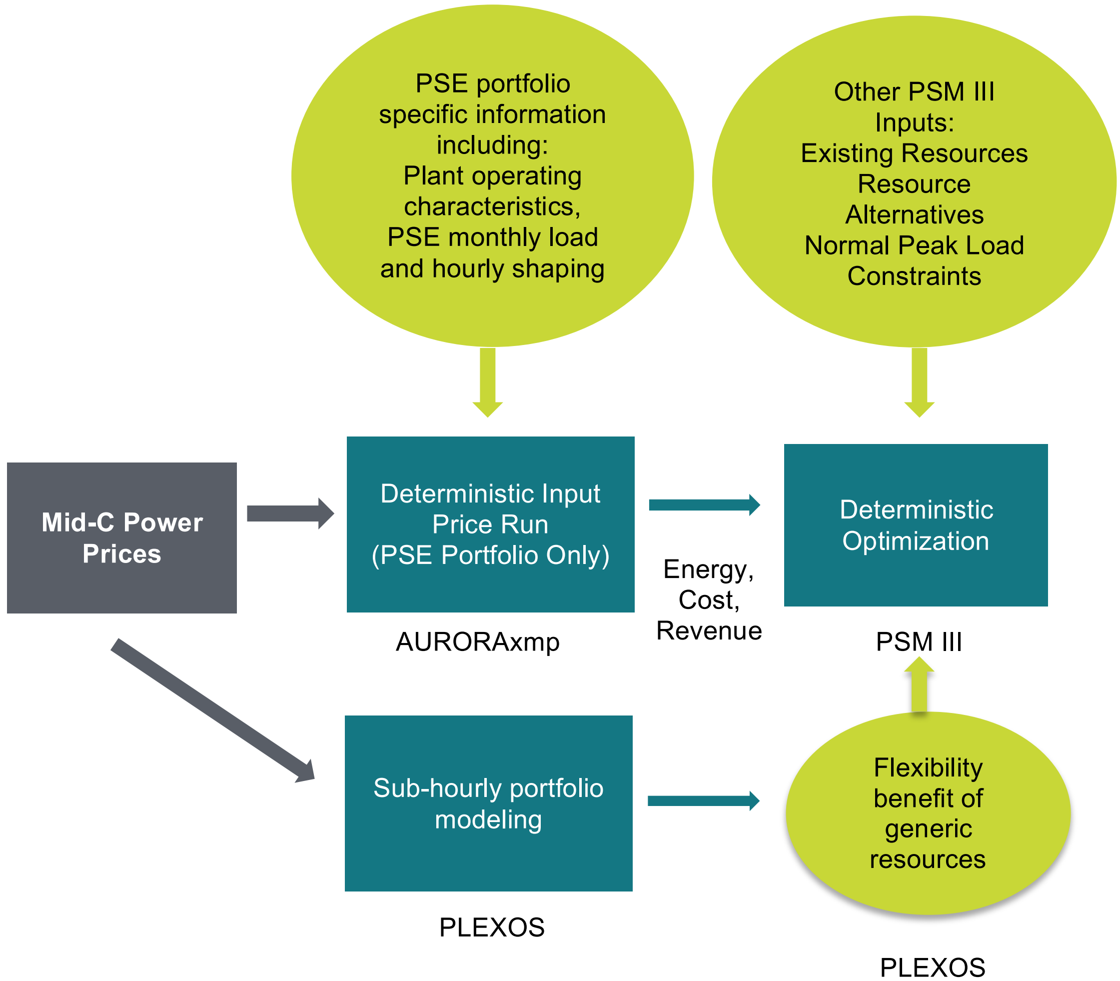


After all of the assumptions are collected and wholesale power prices have been created through AURORA, the next step is portfolio analysis.

Deterministic Portfolio Optimization Analysis

Figure N-3 illustrates PSE's process for creating the lowest cost portfolios through PSM III. Once the power prices are created in AURORA using the WECC-wide database, we use the Mid-C prices as an input to create an input price AURORA analysis. PSE's portfolio is isolated and then dispatched to the Mid-C prices. This AURORA analysis produces estimates of energy (MWh), variable costs including O&M, fuel price and CO_2 price ($000), market revenue ($000), and CO_2 emissions (tons) for all existing and generic resources. The Mid-C power prices are also input into PLEXOS to get the flexibility benefit of each supply-side resource. These results are used as inputs for PSM III to create the least-cost portfolio for a scenario using Frontline Systems' Risk Solver Platform optimization model.

Figure N-3: PSE IRP Modeling Process for Portfolio Optimization



Stochastic Risk Analysis

With stochastic risk analysis, we test the robustness of the candidate portfolios. In other words, we want to know how well the portfolio might perform under different conditions. The goal is to understand the risks of different candidate portfolios in terms of costs and revenue requirements. This involves identifying and characterizing the likelihood of bad events and the likely adverse impacts they may have on a given candidate portfolio.

For this purpose, we take the portfolio candidates (drawn from a subset of the lowest cost portfolios produced in the deterministic analysis) and run them through 250 simulations[1] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed. The goal of the process is to find the set of resources with the lowest cost and the lowest risk.

Analysis Tools

A Monte Carlo approach is used to develop the stochastic inputs. Monte Carlo simulations are used to generate a distribution of resource outputs (dispatched to prices and must-take power), costs and revenues from AURORAxmp. These distributions of outputs, costs and revenues are then used to perform risk simulations in the PSM III model where risk metrics for portfolio costs and revenue requirements are computed to evaluate candidate portfolios.

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 and Conservation Council (NPCC) in its power plans. Additionally, PSE looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. 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.

1 / Each of the 250 simulations is for the twenty-year IRP forecasting period, 2018 through 2037.

2. PORTFOLIO ANLAYSIS MODELS

The AURORA Dispatch Model

PSE uses the AURORA model to estimate the regional wholesale 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.

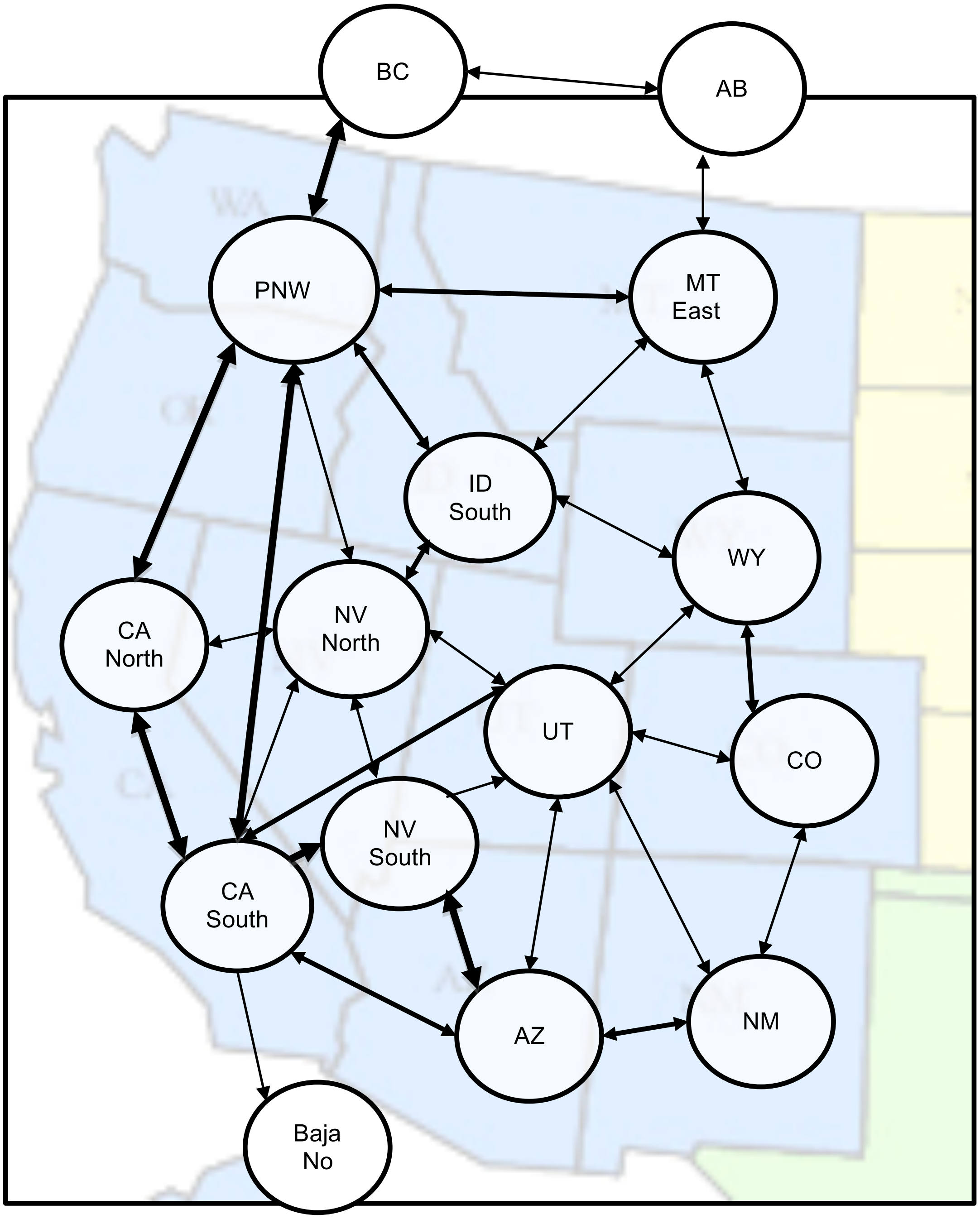
The following text was provided by EPIS, Inc. and edited by PSE.

> AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources and 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.

AURORA estimates all market-clearing prices for the entire WECC, but the market-clearing price used in PSE's modeling is the Mid-Columbia hub, or Mid-C price.

Figure N-4 is a depiction of the AURORA system diagram used for the WECC dispatch. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another. The Pacific Northwest (PNW) Zone is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, northern Idaho and western Montana.

Figure N-4: AURORA System Diagram



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.

PLEXOS/Flexibility Analysis

PLEXOS is used to estimate the impact of selected generic resources on system dispatch cost at a sub-hourly timeframe. PLEXOS is a sophisticated software platform that uses mathematical optimization combined with advanced handling and visualization to provide a high-performance, robust simulation system for electric power, water and gas. It is an hourly and sub-hourly chronological production simulation model which utilizes mixed-integer programming (MIP) to simulate electric power market, and to co-optimize energy and ancillary service provisions. The model first performs unit commitment and economic dispatch at a day-ahead level, and then re-dispatches these resources in real-time to match changes in supply and demand at a sub-hourly level.

For the IRP analysis, PSE utilizes a two-stage simulation approach to represent day-ahead schedule (DA stage) and real-time operations (RT stage) in PLEXOS. The DA stage determines unit commitment decision of PSE's generators on an hourly basis. Reserve requirements at the DA-stage include contingency reserves, regulation up and down reserves, and balancing up and down reserves. The RT stage runs for each 5-minute interval of the year. For each 5-minute interval, online resources will ramp up and/or down to meet the changes in demand and intermittent renewable resources within the hour. Quick-start peaker units can also be started or shut down in the RT stage.

To estimate the flexibility benefit of incremental resources, PLEXOS first runs the base case, which contains only PSE's current resource portfolio. Then, PLEXOS is run again with the addition of one new generic resource. The sub-hourly production cost result of the case with the base portfolio is then compared to the production cost of the case with the additional resource.

Any cost reduction to the portfolio is assumed to be attributed to the new resources. PSE tested each supply-side resource identified in the IRP and incorporated the flexibility benefit to the cost in the portfolio analysis. Except for storage resources, cost reductions that occur in the DA stage are assumed to overlap with PSE's economic evaluation of the resources using AURORA. To avoid double counting, only cost reductions provided at the RT stage (incremental to DA stage cost savings) are added to the portfolio analysis. Since storage resources were not evaluated using AURORA, the full PLEXOS-based cost savings for storage (jointly for the DA and RT stages) is included in the portfolio analysis.

Portfolio Screening Model III (PSM III)

PSM III 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. This model produces the least-cost mix of resources using a linear programming, dual-simplex method that minimizes the present value of portfolio costs subject to planning margin and renewable portfolio standard constraints.

The solver used for the linear programming optimization is Frontline Systems' Risk Solver Platform. This is an Excel add-in that works with the in-house financial model. Incremental costs include: a) the variable fuel cost and emissions for PSE's existing fleet, b) the variable cost of fuel emissions and operations and maintenance for new resources, c) the fixed depreciation and capital cost of investments in new resources, d) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and e) 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:

1. PSE's peak and energy demand forecasts,
2. PSE's existing and generic resources, their capacities and outage rates,
3. expected dispatched energy (MWh), variable cost ($000) and revenue ($000) from AURORAxmp for existing contracts and existing and generic resources,
4. capital and fixed-cost assumptions of generic resources,
5. financial assumptions such as cost of capital, taxes, depreciation and escalation rates,
6. capacity contributions and planning margin constraints,
7. renewable portfolio targets, and
8. flexibility benefit from PLEXOS ($/kw-yr)

Mathematical Representation of PSM III

The purpose of the optimization 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 margin (PM) 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 resource 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.

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 RCS over RPS-required renewable energy at time t
Cap = capacities of generic and existing resources, and DSR 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.

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

$$RR_t = \sum_{gn} d(gn)*[AnnCapCost(gn) + VarCost(gn)] + \sum_{gr} d(gr)*[AnnCapCost(gr) + VarCost(gr)] +$$

$$\sum_{xn} VarCost(xn) + \sum_{xr} VarCost(xr) + ContractCost + DSRCost + NetMktCost - RECSales.$$

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

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

The objective function is subject to two constraints

CONSTRAINT #1. The planning margin was found using PSE's Resource Adequacy Model consistent with the 2015 Optimal Planning Standard. Details about the planning margin can be found later in this appendix. In the model, the planning margin is expressed as a percent, and it is used as a lower bound on the constraint. That is, the model must minimize the objective function while maintaining a minimum of this planning margin 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.

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

CONSTRAINT #2. 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 needed to meet the state RPS. Below is the mathematical representation of how the RPS is used as a constraint for the optimization.

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

d(gn), d(gr) ≥ 0, and are integer values for all t,

Other restrictions include total build limits. For example, for the generic wind, 5 plants may be built in a year, for a total of 10 plants over the 20-year time horizon. In the comparison between east and west builds (relative to the Cascade mountain range), the westside natural gas plants were limited to a total of 1,000 MW over the 20 years for both peakers and baseload CCCT.

The model is solved using Frontline Systems' Risk Solver Platform software that provides various linear, quadratic, and nonlinear programming solver engines in Excel environments. Frontline Systems 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.

End Effects

The IRP calculation of end effects includes the following: a) a revenue requirement calculation is made for the life of the plant, and b) replacement costs are added for plants that retire during end effects to put all proposals on equal footing in terms of service level.

REVENUE REQUIREMENT. Revenue requirement for end effects is based on the operational characteristics of the 20th year in the dispatch model and an estimate of dispatch, based on the last 5 years of AURORA dispatch. The revenue requirement calculation takes into account the return on ratebase, operating expenses, book depreciation and market value of the output from the plant. The operating expenses and market revenues are escalated at a standard escalation rate using an average of the last 5 years of AURORA dispatch as the starting point.

REPLACEMENT COSTS ON AN EQUIVALENT LIFE BASIS. To account for the differences in lives of projects the model includes a replacement resource at the end of the project life in the end effects period. Capacity resources are replaced with an equivalent type and amount of generic capacity resource, while renewable resources are replaced by an equivalent generic wind plant on a REC basis. The fixed capital cost of the replacement resource is added based on the estimated generic resource cost in the year of replacement on a level annual basis – equal annual costs until the end of the end-effects period. The variable cost, market revenue and fixed operations cost are included based on an estimate of the costs using the standard inflation factor and the dispatch from the last 5 years of AURORA dispatch. By adding replacements in end effects on a levelized cost basis, the model is creating equivalent lives for all the resources. The end-effects period extends 34 years beyond the initial 20-year planning horizon.

Monte Carlo Simulations for the Risk Trials

PSE utilized the 250 simulations from the stochastic model as the basis for the 1,000 risk trials. For each of the 1,000 trials, a simulation was chosen at random from the 250 simulations and the revenue requirement for the portfolio was calculated using all the outputs associated with that simulation (Mid-C power price, CO_2 cost/price, Sumas natural gas prices, hydro generation, wind generation and PSE load).

Stochastic Portfolio Model

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of bad events and the likely adverse impacts of their occurrence for any given portfolio. The modeling process used to develop the stochastic inputs is a Monte Carlo approach. Monte Carlo simulations are used to generate a distribution of resource energy output (dispatched to prices and must-take), costs and revenues from AURORAxmp. These distributions of outputs, costs and revenues are then used to perform risk simulations in the PSM III model where risk metrics for portfolio costs and revenue requirements are computed to evaluate alternative portfolios. The stochastic inputs considered in this IRP are Mid-C power price, gas prices for Sumas hub, PSE loads, hydropower generation, wind generation, risk of CO_2 prices and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.

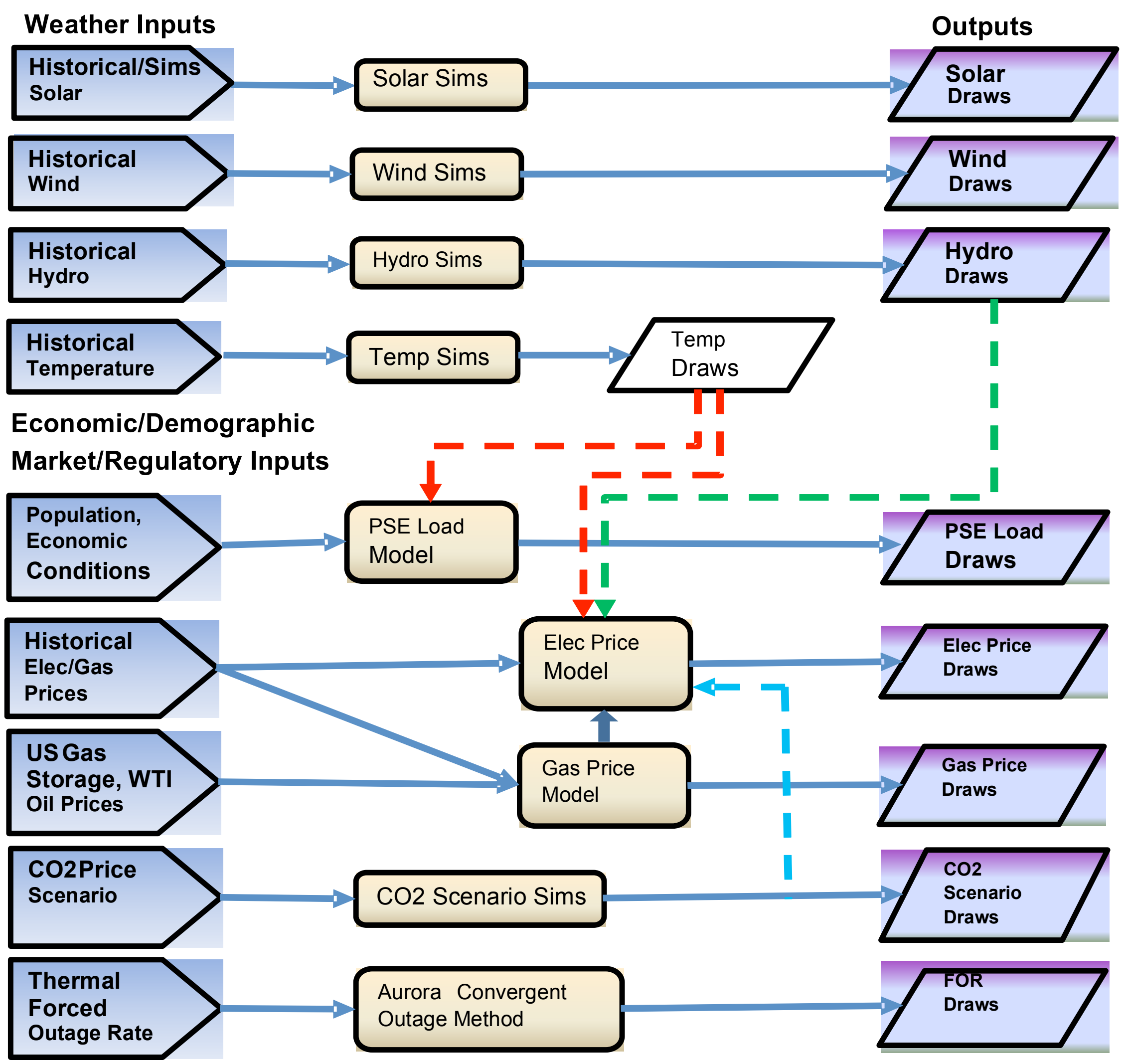
Development of Monte Carlo Simulations for the Stochastic Variables

A key goal in the stochastic model is to be able to capture the relationships of major drivers of risks with the stochastic variables in a systematic way. One of these relationships, for example, is that variations in Mid-C power prices should be correlated with variations in Sumas gas prices, contemporaneously or with a lag. Another important aspect in the development of the stochastic variables is the imposition of consistency across simulations and key scenarios. This required ensuring, for example, that the same temperature conditions prevail for a load simulation and for a power price simulation. Figure N-5 shows the key drivers in developing these stochastic inputs. In essence, weather variables, long-term economic conditions and energy markets, and regulation determine the variability in the stochastic variables. Furthermore, two distinct approaches were used to develop the 250 Monte Carlo simulations for the inputs: a) loads and prices were developed using econometric analysis given their connection to weather variables (temperature and water conditions), key economic assumptions and the risks of CO_2 price policy, and b) temperature, hydro and wind variability were based directly on historical information assumed to be uniformly distributed, while the risks of a CO_2 prices were based on probability weights.

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: a) uncertainty in the coefficient estimate, b) uncertainty in the residual error term, c) the covariate relationship between the uncertainty in the coefficients and the residual error, and d) uncertainty in the relationship between equations that are simultaneously estimated. Monte Carlo simulations 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 N-5: Stochastic Model Diagram



PSE LOAD FORECAST. PSE developed a set of 250 Monte Carlo load forecast simulations by allowing two sets of variable inputs to vary for each simulation: weather and economic-demographic conditions. For each simulation there is no "normal" weather for the forecast horizon. Instead, the 250 simulations draw from 87 weather scenarios, or "weather strips," each with 20 years of consecutive historical temperatures. The first weather strip is historical data starting in 1929 and continuing through 1948. The second weather strip starts in 1930 and continues through 1949. Weather strips starting after 1996 did not have 20 years of consecutive weather data available. Therefore, for each weather strip starting after 1996 the data series continues through 2015, then wraps around to weather from January 1, 1989 and continues from that point. Therefore, recent historical weather is oversampled in the weather scenarios. The temperatures were from two sets of data: a) 1929-1947 data from Portage Bay (near the University of Washington), and b) 1948-2015 data from SeaTac Airport. The heating degree days (HDDs) and cooling degree days (CDDs) were based on each weather strip run through the 20-year demand forecast model to get the impacts on monthly/hourly profiles and use per customer.

Monte Carlo simulations on economic and demographic inputs are based on historical standard errors of growth in macroeconomic and key regional inputs into the model such as population, employment and income. The stochastic simulation also accounts for the error distribution of the estimated customer counts and use-per-customer equations and the estimated equation parameters.

Why does PSE use different historical periods for different load analysis?

The Resource Adequacy Model (RAM) and the load forecasts in the scenario and stochastic portfolio analyses are done using different historical periods because these analyses are used for different types of planning.

The stochastic analysis performed by the RAM uses 80 years of historic weather and hydro conditions in addition to risks in market reliance, variability of wind generation and random forced outages in thermal plants. Because the risks in market reliance need to be consistent with the regional outlook where the 80 years of hydro conditions and 77 years of weather years were imposed, PSE's Resource Adequacy Model was revised to account for these conditions in a consistent way.

The goal of the stochastic portfolio analysis is to examine the resource plans over a wide range of potential futures, knowing the region will not experience normal weather (load) and hydro conditions each year during the planning horizon, including variations in gas and electric prices, wind generation and thermal forced outages. In fact, most years may be abnormal in at least one of the aspects listed above. Understanding the strengths and weakness of each candidate portfolio over a wide variety of potential futures is essential for a thorough analysis of each candidate portfolio. This stochastic portfolio model uses 83 weather years starting from 1929. While no correlations were imposed on weather and hydro conditions, each of these factors was correlated with prices and loads.

Figures N-6 and N-7 depict a graphical representation of the load forecast simulations for energy and peak.

Figure N-6: Load Forecast Simulations – Annual Energy (aMW)

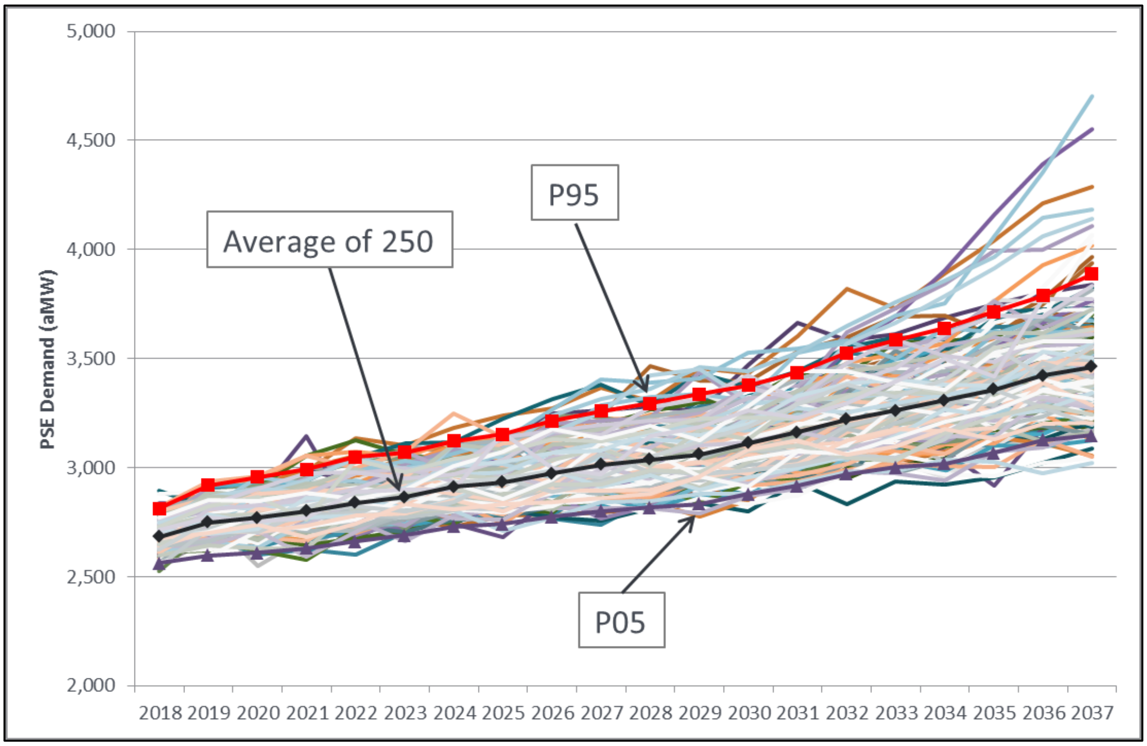
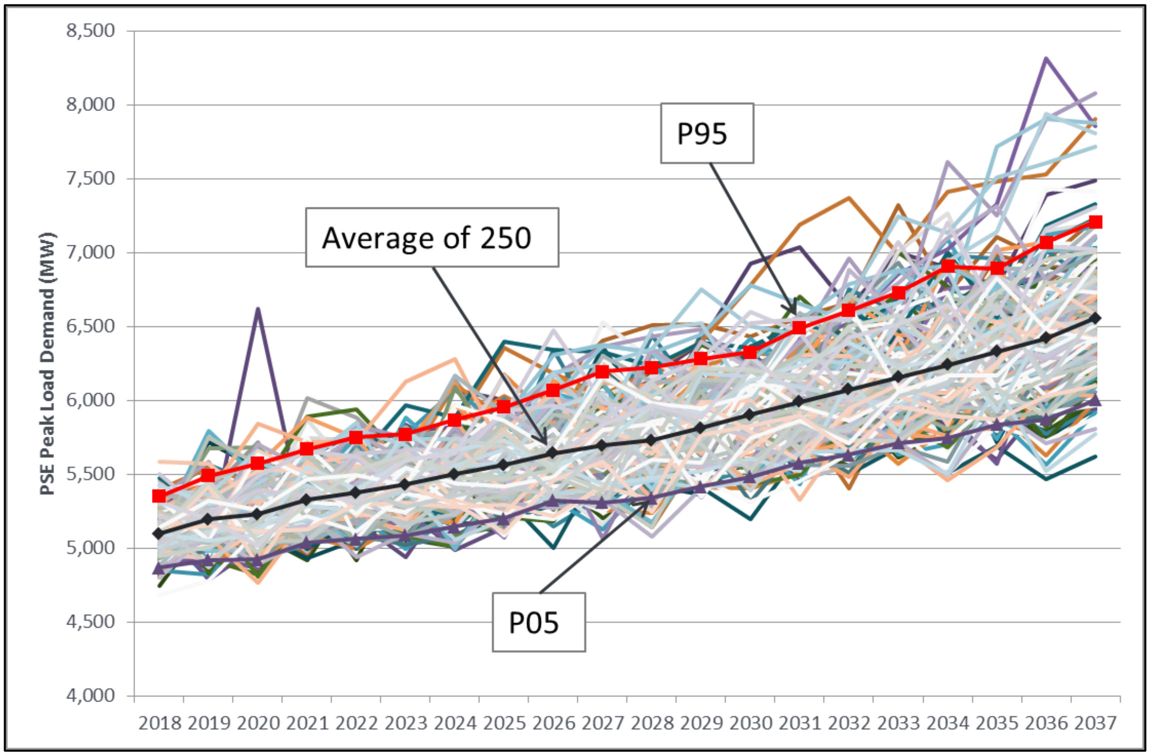


Figure N-7: Load Forecast Simulations – December 1-hour Peak (MW)



GAS AND POWER PRICES. The econometric relationship between prices and their explanatory variables is shown in the equations below:

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

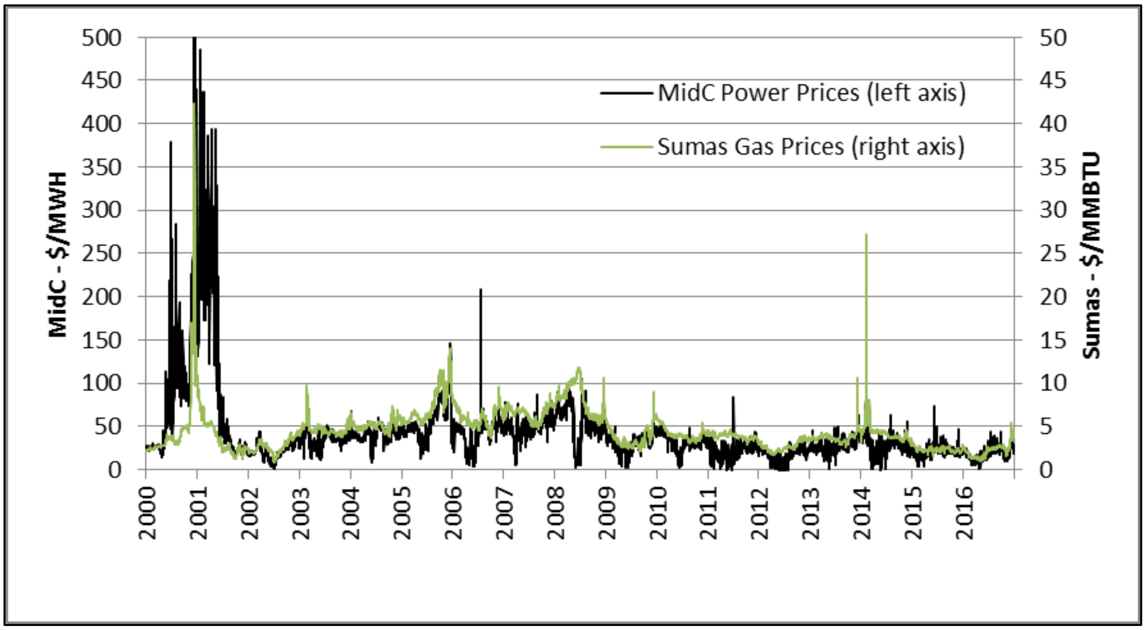
Mid-C Power Price = f(Sumas Gas Price, Regional Temperature Deviation from Normal, Mid-C Hydro Generation, Day of Week, Holidays)

A semi-log functional form is used for each equation. These equations are estimated simultaneously with one period autocorrelation using historical daily data from January 2005 to December 2016. The Fracking Effects in the Sumas gas price equation accounted for the impacts of fracking technology on the historical gas price series starting in 2010.

Monte Carlo simulations were obtained based on the error distributions of the estimated equations, oil price simulations, temperature simulations and hydro condition simulations. Gas price simulations were further adjusted so that the 10th percentile and 90th percentiles correspond to the low and high gas price scenarios, respectively, based on the rank levelized price of each simulation. The price simulations 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. Mid-C power price simulations in the presence of risks of CO_2 cost/price policies were adjusted based on the observed changes in power price forecasts from AURORAxmp model runs when CO_2 costs/prices were imposed at different levels. Mid-C power prices are generally higher when CO_2 costs/prices are included.

Figure N-8 shows the historical trends in daily Mid-C power price and Sumas gas price from 2000 through 2016, including the price spikes in late 2000 to early 2001 due to the California crisis.

Figure N-8: Historical Mid-C Power Price and Sumas Gas Price



The annual Sumas gas price simulations are shown in Figure N-9. The Annual Mid-C power price simulations are shown in Figure N-10.

Figure N-9: Annual Sumas Gas Price Simulations

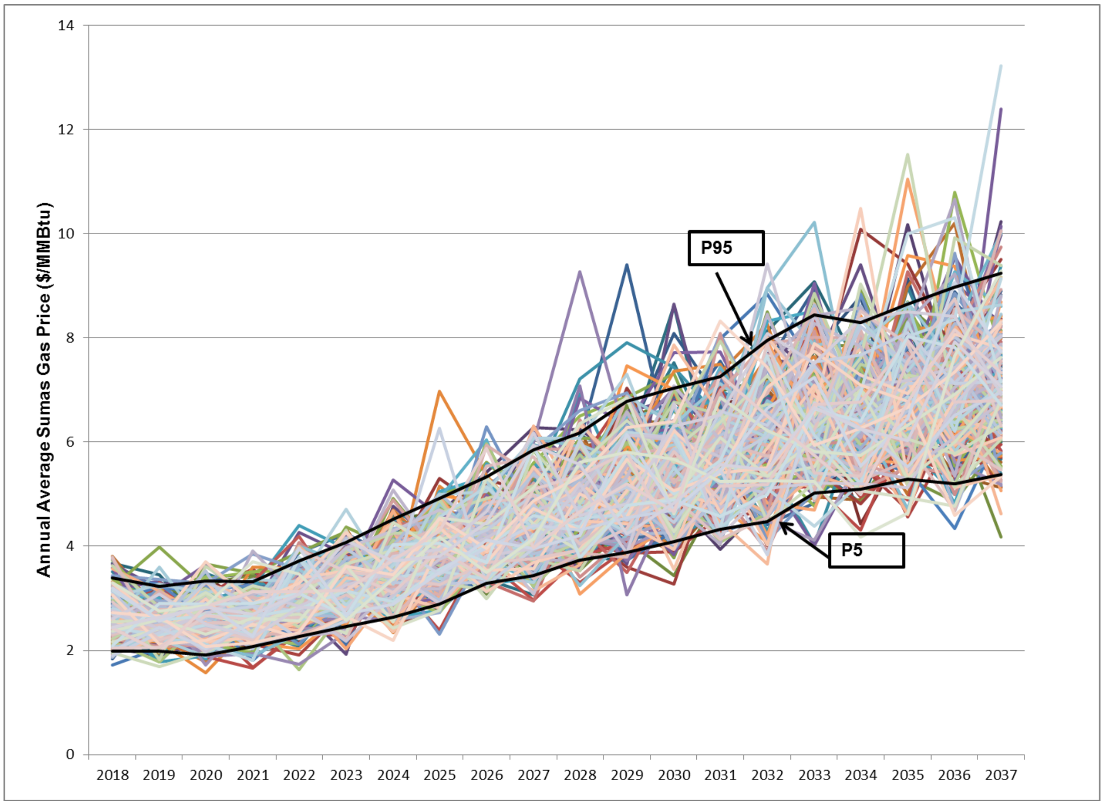
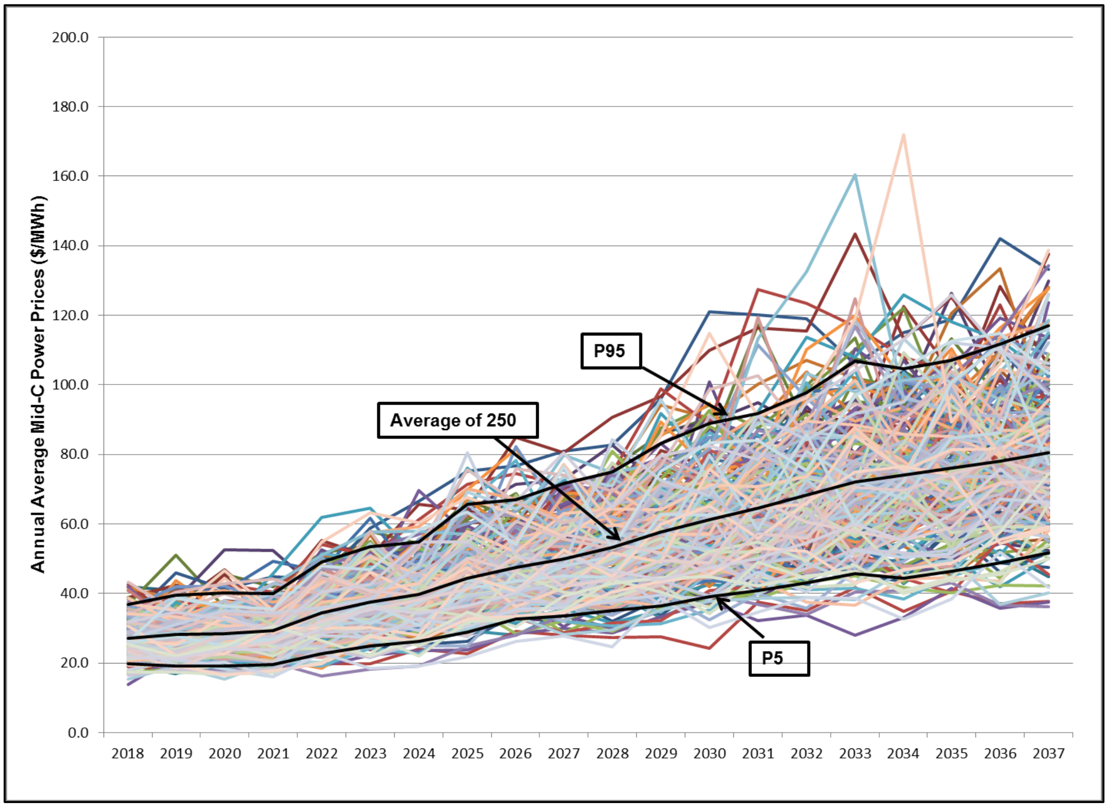
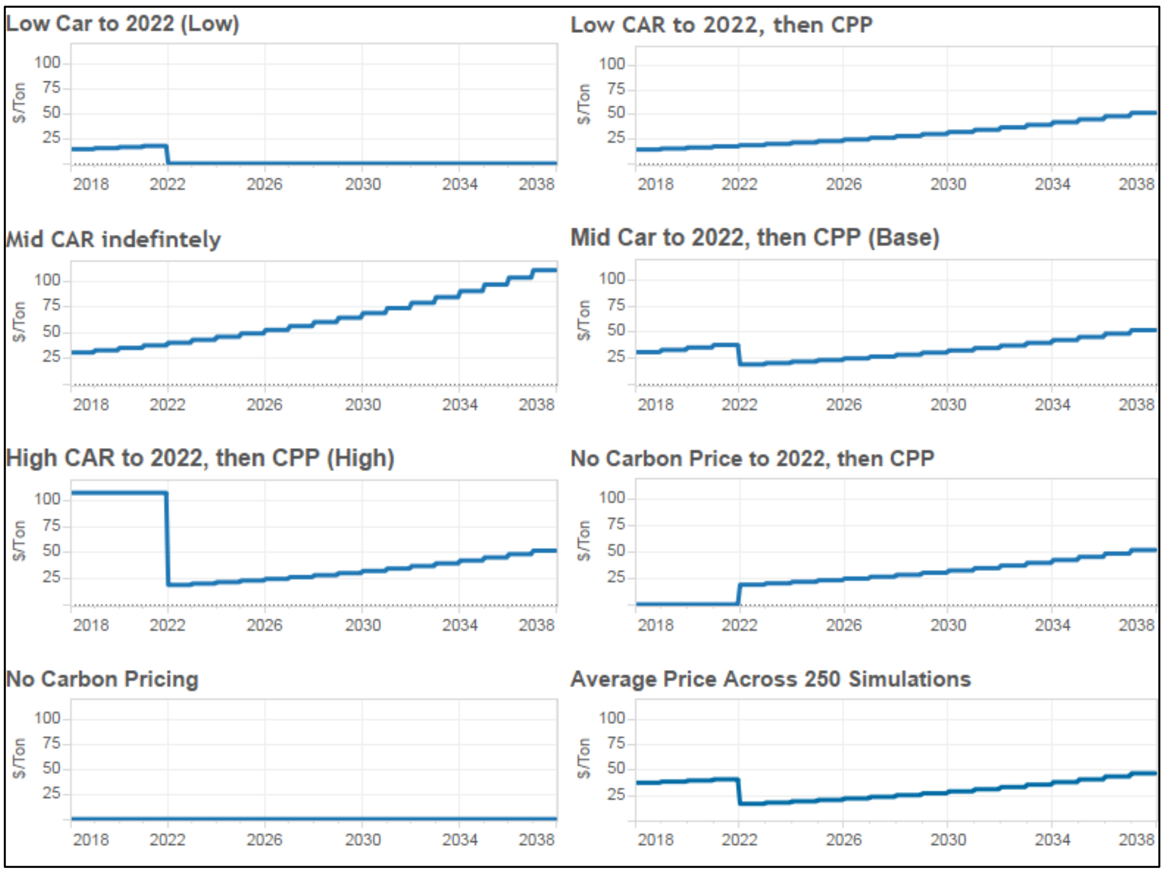


Figure N-10: Annual Mid-C Price Simulations



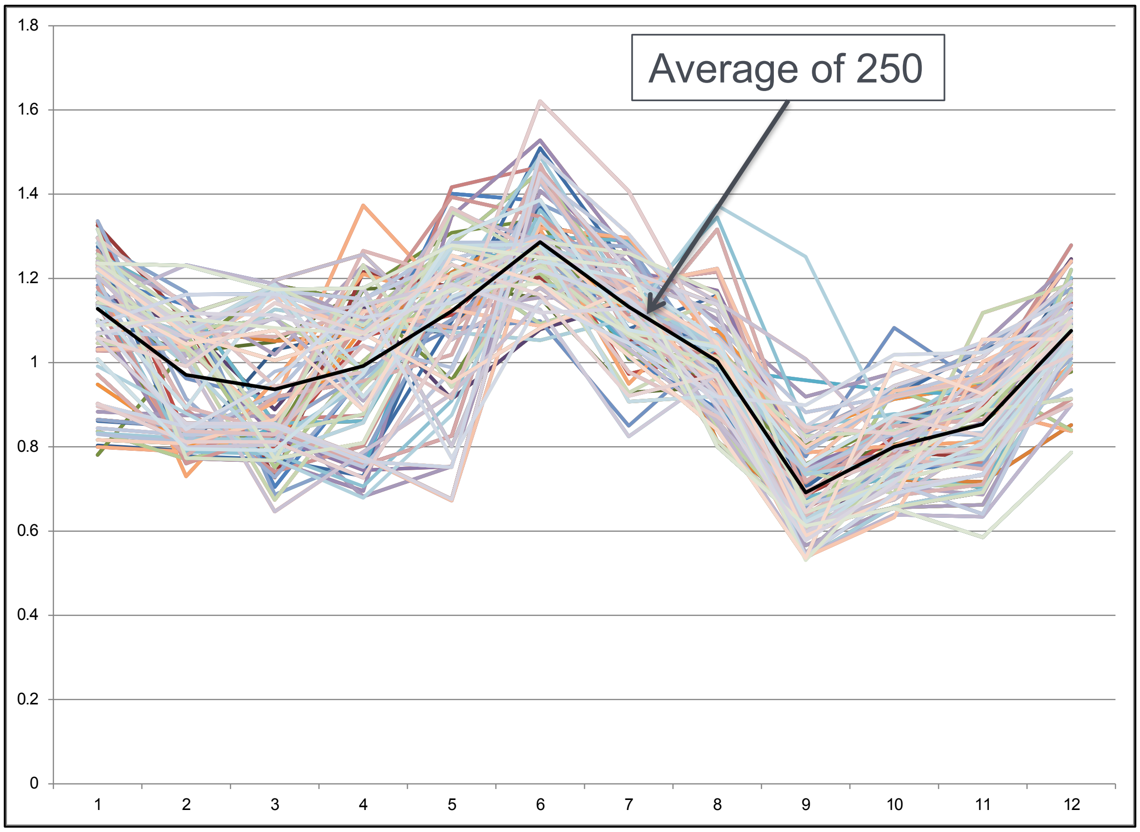
RISKS OF CO_2 PRICE. There exists significant uncertainty around future CO_2 policy, thus PSE modeled several different pricing paths as part of the IRP. Given the possible range of CO_2 price per ton assumed in the deterministic scenarios, as described in Chapter 4, equal probabilities were assigned to each of the 14 scenarios. Figure N-11 shows the annual CO_2 cost/price simulations with the weighted average of all simulations.

Figure N-11: Annual CO_2 Price Inputs, Weighted Average Simulation CO_2 Price



HYDRO GENERATION. Monte Carlo simulations for each of PSE's hydro projects were obtained using the 80-year historical Pacific Northwest Coordination Agreement Hydro Regulation data (1929-2008). 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 simulations. A different set of 250 hydro simulations is applied for each year in the planning horizon. Figure N-12 shows the monthly flows/capacity factors for all five PSE contracted Mid-C projects. See Appendix D for discussion of which projects PSE has contracted.

Figure N-12: Monthly Capacity Factor for 5 Mid-C Hydro Projects



WIND GENERATION. As part of the IRP, PSE models what happens when potential new resources are introduced into PSE's existing portfolio. PSE generates, balances or purchases energy from five different existing wind farms within the region. These existing resources enable the IRP to draw upon four years (2012-2016) of actual simultaneous wind generation across farms. Although this seems sufficient, PSE's IRP models need 250 unique 8,760 hourly profiles, which exhibit the typical wind generation patterns, to test in portfolio stochastics. 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 correlations across wind farms and the seasonality of wind generation are reflected. Thus, to form the 250 unique simulations, we sample a 24-hour day in a given month to form 250 series of 8,760 wind generation profiles. The distribution of the combined 250 simulations reflects the underlying observed distribution of monthly and hourly capacities, as well as observed cross-farm correlations.

Prior to the 2017 IRP, PSE had limited wind generation data to form stochastic wind profiles for new resources. Thus, PSE contracted with DNV GL to independently generate synthetic wind data, informed by their expertise in technical design and environmental operating conditions. DNV GL supplied PSE with 1,000 sets of 8,760 wind profiles ranging from 2000-2016. Sites and technologies modeled included offshore Washington wind, generic eastern Washington wind, generic Montana wind, and generic western Washington wind. For each resource, PSE randomly sampled annual profiles from over 17,000 possible profiles to form a set of 250 8,760 profiles for each resource.

Figure N-13 illustrates the frequency of the annual capacity factor for the generic wind project across all 250 simulations.

Figure N-13a: Wind Simulations,
Frequency of Annual Capacity Factor for 250 Simulations for Generic Resources

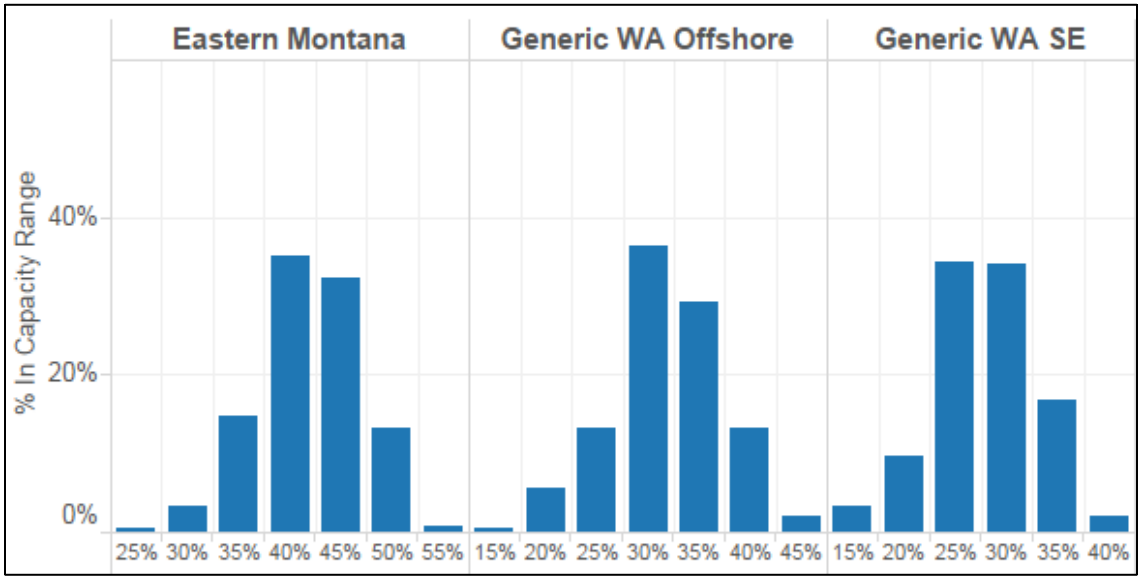


Figure N-13b: Wind Simulations, Box-Whisker Plot of Annual Capacity Factor
for 250 Simulations for Generic Resources

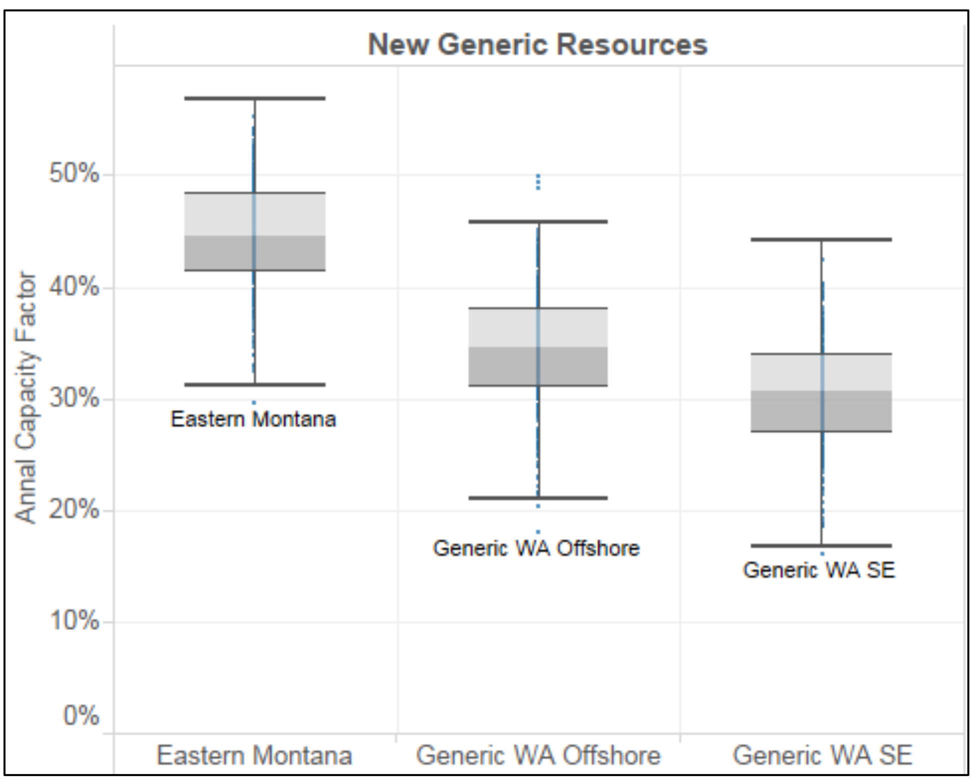


Figure N-14: Wind Simulations,
Sample Moments of 250 Simulations for Generic Resources

Type	Resource	Mean	Standard Deviation	Min	Max	P25	Median	P75
Generic	Eastern Montana	44.6%	4.9%	29.6%	56.9%	41.3%	44.6%	48.3%
	Generic WA Offshore	34.4%	5.6%	18.0%	50.0%	31.0%	34.6%	37.9%
	Generic Eastern WA	30.4%	5.0%	16.0%	44.1%	26.9%	30.6%	33.8%

THERMAL PLANT FORCED OUTAGES. "Convergent" outage method in AURORAxmp is used to model unplanned outages (forced outage) for the thermal plants. This capability ensures the simulated outage rate is convergence to an input forced outage rate in every risk iteration. The actual timing of the outage, however, will change from iteration to iteration. The logic considers each unit's forced outage rate and mean repair time. When the unit has planned maintenance schedule, the model will ignore those hours in the random outage scheduling. In other words, the hours that planned maintenance occurs is not accounted in forced outage rate.

AURORA Risk Modeling of PSE Portfolios

The economic dispatch and unit commitment capabilities of AURORAxmp are utilized to generate the variable costs, outputs and revenues of any given portfolio and input simulations. The main advantage of using AURORAxmp is its fast hourly dispatch algorithm for 20 years, a feature that is 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 within AURORAxmp, however, the set of 250 simulations for all of the risk variables (power prices, gas prices, CO_2 costs/prices, PSE loads, hydro generation and wind generation) are fed into the AURORAxmp model. The thermal plant forced outage is simulated in AURORA at the same time as it is running the dispatch for the simulation. Given each of these input simulations, AURORAxmp then dispatches PSE's existing portfolio and all generic resources to market price. The results are then saved and passed on to the PSM III model where the dispatch energy, costs and revenues for each simulation are utilized to obtain the distribution of revenue requirements for each set of generic portfolio builds.

Risk Simulation in PSM III

In order to perform risk simulation of any given portfolio in PSM III, the distribution of the stochastic variables must be incorporated into the model. The base case 250 simulations of dispatched outputs, costs and revenues for PSE's existing and generic resources were fed into PSM III from AURORAxmp and the stochastic model as described above. Note that these AURORAxmp outputs have already incorporated the variability in gas and power prices, CO_2 price, PSE's loads, hydro and wind generation from the stochastic model. Frontline Systems' Risk Solver Platform Excel add-on allows for the automatic creation of distributions of energy outputs, costs and revenues based on the 250 simulations that PSM III can utilize for the simulation analysis. In addition, peak load distribution, consistent with the energy load distribution, was incorporated into the PSM III. 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 market purchased power costs. The results of the risk simulation are presented in Chapter 6 and in the "Outputs" section of this appendix.

3. KEY INPUTS AND ASSUMPTIONS

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 synchronous regions, and limited electricity transactions occur 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 can be traded along several paths in the WECC through these areas, but can only be traded to other interconnections via direct current tie lines.

For modeling purposes, the WECC is divided into 16 zones, primarily by state and province, except for California which has three zones and Nevada which has two areas. Oregon, Washington, Idaho north and Montana west are combined into one zone, which is used to represent Mid-C market. These zones approximate the actual market activity in the WECC.

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 the EPIS North_American_DB_2016_v3 version produced in April 2016 with updates to include coal, NG plant retirements, and new WECC builds. See following sections for more details.

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 the Section titled “Renewable Portfolio Standard (WECC),” below.

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 80 historical years of 1929 to 2008. 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 using the 80-year historical stream flows.

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. The 2017 IRP uses default transmission lines assumptions in EPIS's North_American_DB_2016_v3.

Regional Load Forecast

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 2017 IRP, load forecasts for Oregon, Washington, Montana and Idaho were based on the Northwest Power and Conservation Council (NPCC) 2016 regional forecast mid-term update load forecast, net of conservation.

Natural Gas Prices

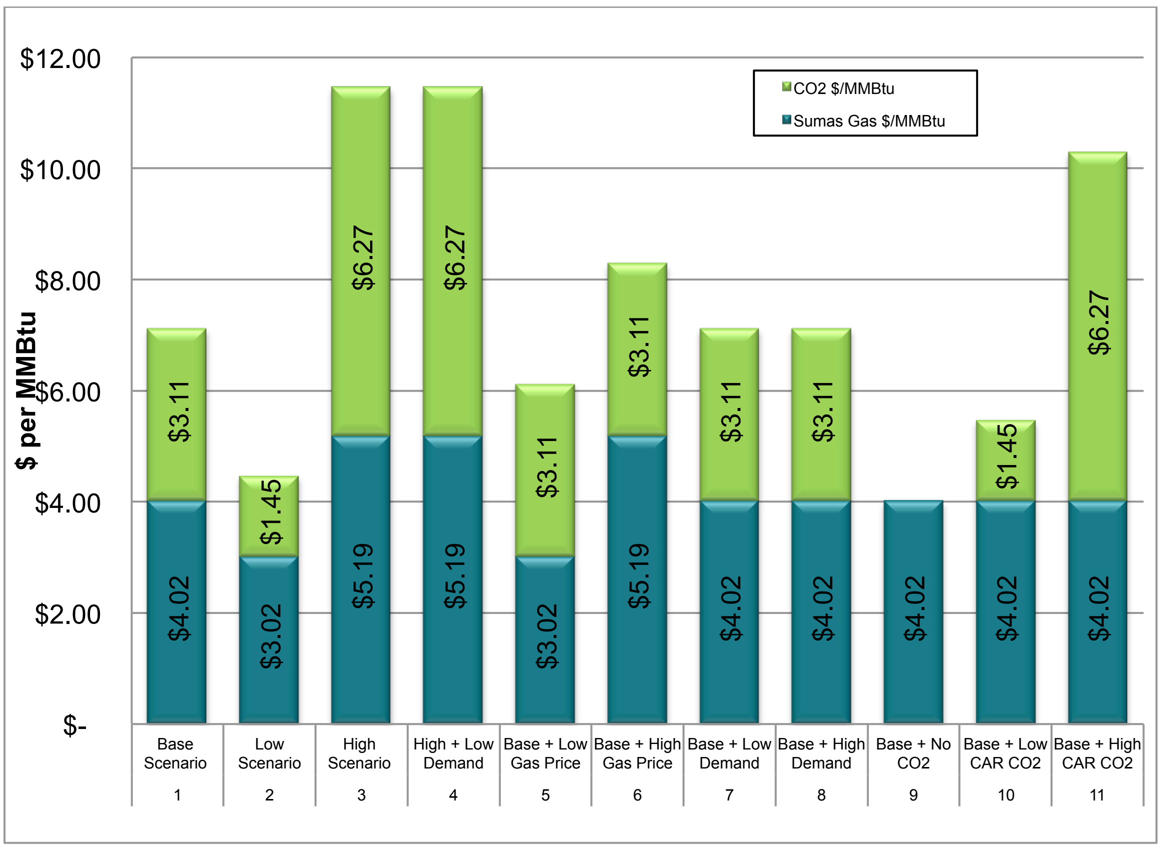
For gas price assumptions, PSE uses a combination of forward market prices, fundamental forecasts acquired in November 2016 from Wood Mackenzie. Wood MacKenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas (LNG) exports. Three gas price forecasts are used in the scenario analysis.

LOW GAS PRICES. These reflect Wood Mackenzie's long-term low price forecast for 2018-2037.

MID GAS PRICES. From 2018-2021, this IRP uses the three-month average of forward marks for the period ending November 27, 2016. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2021, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts. The 2017 IRP Base Scenario uses this forecast.

HIGH GAS PRICES. These reflect Wood Mackenzie's long-term high price forecast for 2018-2037.

Figure N-15: Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized 2018-2037, nominal $)



CO_2 Price

The carbon prices in this IRP reflect the range of potential impacts from several key pieces of carbon regulation. The two most important carbon regulations are reflected in the 2017 IRP. They are Washington state's Clean Air Rule (CAR) and the federal Environmental Protection Agency Clean Power Plan (CPP) rules. CAR regulations apply to both electric and gas utilities, and CPP regulations apply only to baseload electric resources. The annual CAR CO_2 prices modeled are presented in Figure N-16 and CPP CO_2 prices are presented in Figure N-17.

Mid CO_2 prices

The 2017 IRP Base Scenario uses this forecast.

MID CAR TO 2022 - $30 PER TON IN 2018 TO $111 PER TON IN 2037

CPP FROM 2022-2037 – $19 PER TON IN 2022 TO $52 PER TON IN 2037

CAR estimate is based on the Washington Dept. of Ecology's cost/benefit analysis of the CAR. CPP estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32 and is applied WECC-wide as a CO_2 price to all existing and new baseload generating units affected under the CPP.

Low CO_2 prices

LOW CAR CO_2 PRICE TO 2022: $15 PER TON IN 2018 TO $51 PER TON IN 2037

NO CPP

CAR estimate is based on Wood MacKenzie's estimated CO_2 price for California.

High CO_2 Prices

HIGH CAR CO_2 PRICE TO 2022: $108 PER TON IN 2018 TO $108 PER TON IN 2037

CPP FROM 2022-2037: $19 PER TON IN 2022 TO $51 PER TON IN 2037

CAR estimate is based on PSE's fundamental REC price from the 2015 IRP. It reflects the difference between the levelized cost of power and the levelized cost of wind in the 2015 IRP. CPP estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32.

Figure N-16: Annual CAR CO_2 Costs (Nominal $/Ton)

	Low	Base	High
2018	15.41	30.71	107.75
2019	16.59	32.87	107.75
2020	17.85	35.18	107.75
2021	19.22	37.64	107.75
2022	-	40.27	107.75
2023	-	43.09	107.75
2024	-	46.11	107.75
2025	-	49.34	107.75
2026	-	52.78	107.75
2027	-	56.48	107.75
2028	-	60.44	107.75
2029	-	64.67	107.75
2030	-	69.21	107.75
2031	-	74.06	107.75
2032	-	79.24	107.75
2033	-	84.78	107.75
2034	-	90.70	107.75
2035	-	97.05	107.75
2036	-	103.83	107.75
2037	-	111.09	107.75

Figure N-17: Annual CPP CO_2 Costs (Nominal $/Ton)

	Low	Mid
2018	-	14.36
2019	-	15.37
2020	-	16.45
2021	-	17.60
2022	-	18.82
2023	-	20.14
2024	-	21.55
2025	-	23.06
2026	-	24.67
2027	-	26.40
2028	-	28.25
2029	-	30.23
2030	-	32.35
2031	-	34.62
2032	-	37.04
2033	-	39.63
2034	-	42.40
2035	-	45.37
2036	-	48.54
2037	-	51.93

Figure N-18a: CO_2 Prices by Scenario with CAR and CPP Combined

	CO2 Price	Base[1]	Low	High[2]	Base No CO2	Base + Low CAR CO2	Base + High CAR CO2
2018	CAR	30.71	0.00	107.75	0	15.41	107.75
2019	CAR	32.87	0.00	107.75	0	16.59	107.75
2020	CAR	35.18	0.00	107.76	0	17.85	107.76
2021	CAR	37.64	0.00	107.75	0	19.22	107.75
2022	CPP	18.82	0.00	18.82	0	18.82	18.82
2023	CPP	20.14	0.00	20.14	0	20.14	20.14
2024	CPP	21.56	0.00	21.56	0	21.56	21.56
2025	CPP	23.06	0.00	23.06	0	23.06	23.06
2026	CPP	24.67	0.00	24.67	0	24.67	24.67
2027	CPP	26.40	0.00	26.40	0	26.4	26.4
2028	CPP	28.25	0.00	28.25	0	28.25	28.25
2029	CPP	30.23	0.00	30.23	0	30.23	30.23
2030	CPP	32.35	0.00	32.35	0	32.35	32.35
2031	CPP	34.62	0.00	34.62	0	34.62	34.62
2032	CPP	37.04	0.00	37.04	0	37.04	37.04
2033	CPP	39.63	0.00	39.63	0	39.63	39.63
2034	CPP	42.40	0.00	42.40	0	42.4	42.4
2035	CPP	45.37	0.00	45.37	0	45.37	45.37
2036	CPP	48.54	0.00	48.54	0	48.54	48.54
2037	CPP	51.93	0.00	51.93	0	51.93	51.93

NOTES
1. Scenarios Base + Low Gas, Base + High Gas, Base + Low Demand, and Base + High Demand have the same CO_2 prices as the Base Scenario.
2. Scenario High +Low Demand has the same CO_2 prices as the High Scenario.

Figure N-18b: CO_2 Prices by Scenario by Single CO_2 Policy

	Base w/ CAR only	Base w/ CPP only	Base + All-thermal CO2
2018	30.71	0.00	14.36
2019	32.87	0.00	15.37
2020	35.18	0.00	16.45
2021	37.64	0.00	17.60
2022	40.27	18.82	18.82
2023	43.09	20.14	20.14
2024	46.11	21.56	21.56
2025	49.34	23.06	23.06
2026	52.78	24.67	24.67
2027	56.48	26.40	26.40
2028	60.44	28.25	28.25
2029	64.67	30.23	30.23
2030	69.21	32.35	32.35
2031	74.06	34.62	34.62
2032	79.24	37.04	37.04
2033	84.78	39.63	39.63
2034	90.7	42.40	42.40
2035	97.05	45.37	45.37
2036	103.83	48.54	48.54
2037	111.09	51.93	51.93

Emission Standards/Coal-fired Power Plant Retirements

PSE added constraints on coal technologies to the AURORA model in order to reflect current political and regulatory trends. Specifically, no new coal builds were allowed in any state in the WECC. The EPIS's North_American_DB_2016_v3 database was used in this IRP, which includes planned coal power plant retirement. Planned retirements are shown in tables N-19 below.

Figure N-19: Planned Coal Retirements across the WECC (USA)

Planned Coal Retirement (2017 -2037)	MW
Planned Retirement (Pacific Northwest, USA)	2,575
Planned Retirement (Rocky Mountain)	1,139
Planned Retirement (Southwest)	1,040
Total Planned Retirement	**4,754**

Natural Gas-fired Power Plant Retirements

Planned natural gas power plant retirements by year and region are shown in table N-20 below. Most of the natural gas-fired power plants will retire before the end of 2025. Among the 7,459 MW retirements, 7,002 MW is in CA, which is due to Once-Through-Cooling (OTC) rules issued by the State Water Resources Board of California on May 4, 2010. The State Water Resources Board of California adopted a statewide water quality control policy on the use of Once-Through-Cooling (OTC) power plants (nuclear and non-nuclear facilities). This policy establishes requirements for the implementation of the Clean Water Act Section 316 (b), using best professional judgment in determining Best Technology Available (BTA) for cooling intake structures at existing coastal and estuarine plants.

Figure N-20: Planned Natural Gas Retirements in the WECC (USA)

Planned Natural Gas Retirement (2017-2037)	MW
California	7,002
Pacific Northwest, USA	0
Rocky Mountain	0
Southwest	457
Total Planned Retirement	**7,459**

WECC Builds

We used EPIS's North_American_DB_2016_v3 database, which includes a 128 MW new natural gas plant. We added 3,983 MW of new natural gas plant builds in WECC region, based on the data from the SNL Energy database[2] as of September 2016. The total new builds for gas plants from 2016 to 2037 is 4,111 MW. Few renewable resources are added after 2016 in the EPIS database. Since we have an RPS standard for each state in WECC, the renewable resources will be reflected by RPS requirement and added by AURORA as the result of the WECC capacity expansion run. Figure N-21 provides the natural gas new build capacity for each of the WECC sub-regions from 2016 to 2037.

Figure N-21: Planned New Builds in the WECC (USA)

WECC Sub-region	NG Planned build (MW)
Pacific Northwest	460
Rocky Mountain	40
California	1,793
Southwest	1,818
Total	**4,111**

Renewable Portfolio Standard (WECC)

Renewable portfolio standards (RPS) currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE used the same method from the NPCC Seventh Power Plan. NPCC first identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g., 3 percent in 2015, then 15 percent in 2020, etc.). Then they apply those requirements to each state's load. No retirement of existing WECC renewable resources is assumed, which perhaps underestimates the number of new resources that need to be constructed. After existing and planned renewable energy resources are accounted for, "new" renewable energy resources are matched to the load to meet the applicable RPS. Following a review for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass and geothermal.

2 / SNL, which stands for Savings and Loan, is a company that collects and disseminates corporate, financial and market data on several industries including the energy sector (www.snl.com).

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.

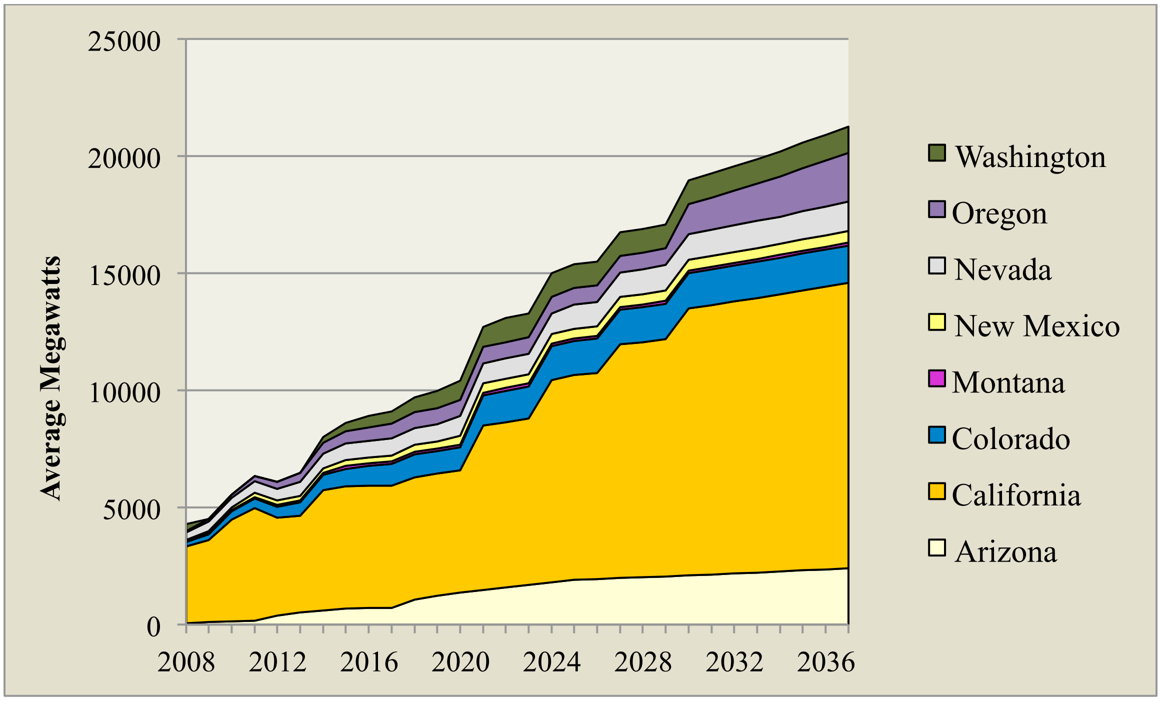
Figure N-22: RPS Requirements for States in the WECC

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.
Montana	5% of sales (net of line losses) to retail customers in 2008 and 2009; 10% from 2010 to 2014; and 15% in 2015 and thereafter. At least 50 MW must come from community renewable energy projects during 2010 to 2014, increasing to 75 MW from 2015 onward. Utilities are to conduct RFPs for renewable energy or RECs and after contracts of at least 10 years in length, unless the utility can prove to the PSC the shorter-term contracts will provide lower RPS compliance costs over the long-term. Preference is to be given to projects that offer in-state employees or wages.	The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW.

State	Standard (LBNL)	Notes for AURORA Modeling
Nevada	6% in 2005 and 2006 and increasing to 9% by 2007 and 2008, 12% by 2009 and 2010, 15% by 2011 and 2012, 18% by 2013 and 2012, ending at 20% in 2015 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane) and not more than 25% of the required standard can be based on energy efficiency measures.	The Renewable Energy Atlas shows that considerable geothermal energy and solar energy potential exists. For modeling the resources are located in the northern and southern part of the state respectively, with the remainder made up with wind.
New Mexico	Senate Bill 418 was signed into law in March 2007 and added new requirements to the state's Renewable Portfolio Standard, which formerly required utilities to get 10% of their electricity needs by 2011 from renewables. Under the new law, regulated electric utilities must have renewables meet 15% of their electricity needs by 2015 and 20% by 2020. Rural electric cooperatives must have renewable energy for 5$ of their electricity needs by 2015, increasing to 10% by 2020. Renewable energy can come from new hydropower facilities, from fuel cells that are not fossil-fueled, and from biomass, solar, wind, and geothermal resources.	New Mexico has a relatively large amount of wind generation currently for its small population. New resources are not required until 2015, at which time they are brought in as wind generation.
Oregon	Senate Bill 1547 was signed into law in 2016. Large utility targets: 50% by 2040. Large utility sales represented 73% of total sales in 2002. Medium utilities 10% by 2025. Small utilities 5% by 2025.	We followed the NWPCC 6th Power Plan assumption for REC banking in the state of Oregon.
Utah	Utah enacted The Energy Resource and Carbon Emission Reduction Initiative (S.B. 202) in March 2008. While this law contains some provisions similar to those found in renewable portfolio standards (RPSs) adopted by other states, certain other provisions in S.B. 202 indicate that this law is more accurately described as a renewable portfolio goal (RPG). Specifically, the law requires that utilities only need to pursue renewable energy to the extent that it is "cost-effective" to do so. Investor-owned utilities, municipal utilities and cooperative utilities must meet 20% of their 2025 adjusted retail electric sales.	
Washington	Washington state's RPS, I-937 (which became RCW 19.285) was passed in 2006 and requires 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.	Assumed any new generic renewables will meet the criteria for the extra 20% REC credit.

In order to reflect RPS requirements in the 20-year planning horizon, renewable resource capacities were calculated, and they were treated as new resources in the AURORA resource table.

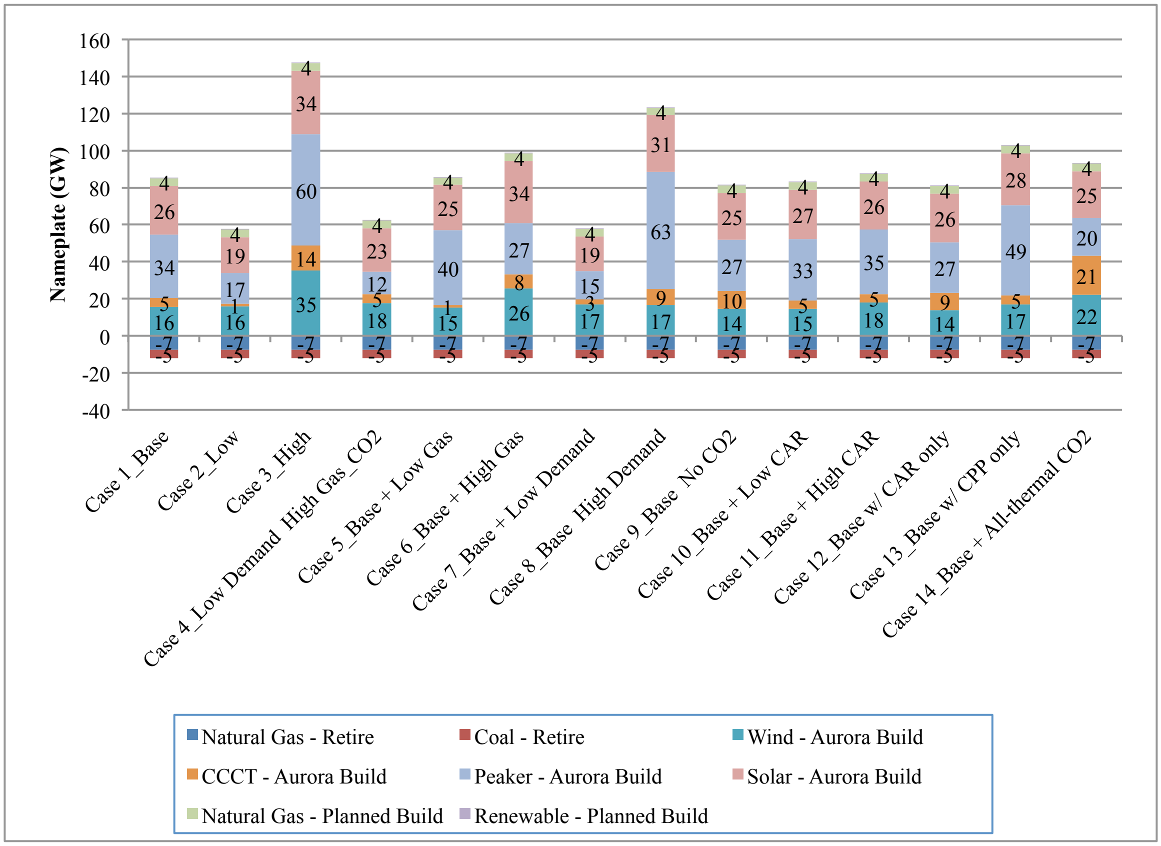
Figure N-23: RPS Builds Added to AURORA Database by State



AURORA Builds

AURORA is able to run a long-term optimization model to choose a set of available supply to meet both energy needs and peak needs. 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. Figure N-24 shows AURORAxmp builds in the 14 scenarios along with planned, retired and RPS capacity described above for both the U.S. and Canada WECC.

Figure N-24: WECC Total Builds/Retirements by 2037



Production Tax Credit Assumptions

The PTC is phased down over time: 100 percent in 2016, 80 percent in 2017, 60 percent in 2018 and 40 percent in 2019. A project must meet the physical test or show that 5 percent or more of the total cost of the project was paid during that year. For example, if a project began construction or paid 5 percent or more in costs in the year 2019, it will receive the 40 percent PTC even if the facility doesn't go online until 2022. The PTC is received over 10 years and is given as a variable rate in dollars per MWh.

Investment Tax Credit Assumptions (ITC)

The ITC is a one-time benefit based on the total capital cost invested in the project. The phase-down over time varies depending on the technology:

- Wind: 30 percent in 2016, 30 percent in 2017, 24 percent in 2018 and 18 percent in 2019;
- Solar: 30 percent 2016-2019, 26 percent in 2020 and 22 percent in 2021.

The ITC benefit is based on the year that construction begins. For example, if a wind project starts construction in 2016 but does not go online until 2018, it will receive a 30 percent tax credit based on the total capital cost. So, if the project cost $300 million, then the developer will receive $90 million in tax benefits.

Treasury Grant Assumptions

The Treasury Grant (Grant) is subsidy that amounts to 30 percent of the eligible capital cost for renewable resources; it also expired at the end of 2013. For projects placed in service in 2013, construction must have started in 2009, 2010 or 2011, and the project must meet eligibility criteria. This subsidy differs from the previous two in that it is a cash payment from the federal government, versus a tax credit. No extension of the Treasury Grant is assumed.

PSM III Inputs

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.

Discount Rate

We used the pre-tax weighted average cost of capital (WACC) from the 2017 General Rate Case of 7.74 percent nominal.

REC Price

The REC price starts at $4.25 per MWh in 2018 and escalates to $15.22 per MWh in 2037. The escalation rate is not uniform for the whole 20-year planning horizon. A major increase occurs in 2020 with an approximate 129.6 percent increase, corresponding to the RPS increase. All other years use a 2.5 percent escalation.

Inflation Rate

The 2017 IRP uses a 2.5 percent escalation for all assumptions unless otherwise noted. This is the long-run average inflation rate that the AURORAxmp model uses.

Transmission Inflation Rate

In 1996, the BPA rate was $1.000 per kW per year and the estimated total rate in 2015 is $1.798 per kW per year. Using the compounded average growth rate (CAGR) of BPA Point-to-Point (PTP) transmission service (including fixed ancillary service Scheduling Control and Dispatch) from 1996 to 2015, we estimated the nominal CAGR inflation rate to be 3.05 percent annually.

Gas Transport Inflation Rate

Natural gas pipeline rates are not updated often and recent history indicates that the rates are 0 percent. PSE has assumed zero inflation on pipeline rates because the major pipelines on which we operate have declining rate base and major expansions will be incrementally priced. Growth in cost of service from operating costs and maintenance capital additions are expected to be offset by declines due to depreciation.

Resource Adequacy Models and Planning Standard

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin for capacity is, in general, defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of service reliability to customers under peak load conditions. 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 in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads) / Normal Peak Loads,

> Where Generation Capacity (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model. This generation capacity includes existing and incremental capacity required to meet the reliability standard.

The planning margin framework allows for the derivation of multiple reliability/risk metrics (such as the likelihood, magnitude and duration of supply-driven customer outages) that, in turn, can be used to quantify the relative capacity contributions of different resource types towards meeting PSE's firm peak loads. These include thermal resources, variable energy resources such as wind, wholesale market purchases, and energy limited resources such as energy storage, demand response and backup fuel capacity.

PSE's Resource Adequacy Model (RAM)

PSE developed its probabilistic Resource Adequacy Model to quantify physical supply risks as PSE's portfolio of loads and resources evolves over time. This model provides the framework for establishing peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin. The RAM is also utilized to compare the relative capacity contribution of intermittent supply-side resources that are subject to random production patterns and to express those contributions in equivalent terms (i.e. their effective load carrying capability or ELCC). Since PSE is a winter-peaking electric utility, its capacity planning standard and associated planning margin are based upon its forecasted ability to reliably meet winter season firm peak loads.

Consistency with Regional Resource Adequacy Assessments

Consistency with the NPCC's regional probabilistic GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM. The PSE existing resources included in this analysis are Colstrip, Mid-Columbia purchase contracts and western Washington hydroelectric resources, several gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. This reliance on market purchases requires that PSE's resource adequacy modeling adequately reflect regional adequacy conditions also.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 6,160 simulations made in the NPCC's GENESYS model in terms of temperature, hydro conditions and thermal outage rates. In addition, PSE's RAM utilizes the same October 2020 – September 2021 study period as the regional GENESYS model.
The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

1. **FORCED OUTAGE RATE FOR THERMAL UNITS**. Modeled as a combination of an outage event and duration of an outage event, subject to mean time to repair and total outage rate equal to the values used in GENESYS.

2. **HOURLY SYSTEM LOADS**. Modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 77 temperature years from 1929 to 2005 to preserve its chronological order, consistent with the GENESYS model.

3. **MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 6,160 combinations of hydro and temperature simulations are consistent with the GENESYS model.

4. WHOLESALE MARKET PURCHASES. These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained in Appendix G. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM.

5. WIND. Drawn randomly from historical hourly data for PSE's Wild Horse and Hopkins Ridge plants, but constrained for the following: 1) simulations 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 to preserve seasonality; 2) simulations across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse; 3) PSE's Lower Snake River wind farm, which does not yet have a long-term generation data record, is assumed to have the same wind profile as Hopkins Ridge, with a 10-minute lag since it is located near Hopkins Ridge, and it is scaled to its nameplate capacity and pro-forma capacity factor.

Treatment of Operating Reserves in the RAM

PSE is required to maintain contingency reserves pursuant to the Northwest Power Pool (NWPP) reserve sharing agreement. Members are required to hold 3 percent of load and 3 percent of online dispatched generation in reserve, in case any member experiences an unplanned generating plant outage. In addition, half of the contingency reserves should be in spinning reserve capable of responding within ten minutes. In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60-minute period, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power, or curtailing load. PSE's RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, if a forced outage at one of PSE's generating plants causes loads to exceed available resources.

PSE's planning margin is calculated net of operating reserves, which are the sum of contingency reserves (as described above) and within-hour balancing resources. The total amount of contingency reserves and balancing reserves maintained by PSE can vary depending upon the magnitude of the resources and loads located in the PSE balancing authority area and the generating capacity needed to meet short-term system flexibility requirements.

Risk Metrics

The probabilistic resource adequacy model (RAM) allows for the calculation of several risk metrics including: 1) the loss of load probability (LOLP), which measures the likelihood of a load curtailment event occurring in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s), 2) the expected unserved energy (EUE), which measures magnitude in MWh and is the sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations, and 3) loss of load hours (LOLH) which measures outage duration and is the sum of the hours with load curtailments divided by the number of simulations. Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these three risk metrics, once a planning standard has been established.

Determining PSE's Capacity Planning Margin

In this IRP, PSE adopts the reliability standard established for the Pacific Northwest region through the NW Regional Adequacy Forum.[3] This standard utilizes the LOLP metric and establishes the 5 percent LOLP level as adequate for the region. This LOLP value is obtained by running the 6,160 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using a CT plant as the "typical" peaking plant, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

Input Updates to the Resource Adequacy Model for the 2017 IRP

For the 2017 IRP resource adequacy study, the calculation of the resource capacity needed to meet the 5 percent LOLP standard excluded DSR since the optimal DSR amount will still be determined in the portfolio optimization model. In addition to the exclusion of DSR in the study, the following key updates to the RAM inputs were also made.

1. The load forecast was updated to reflect F16 assumptions; lower population growth rate, lower normal heating degree days because recent years have been much warmer than normal, and economic growth and modelling uncertainties introduced in the stochastic load simulations.
2. PSE's resource capacities were updated to reflect capacity changes in both hydro and thermal resources; slightly reduced capacities in PSE-owned hydro and slightly higher capacities in thermals due to upgrades to the combined-cycle peaking units.
3. The hourly draws of the existing PSE wind fleet were updated to include one more year of actual data.
4. Colstrip Units 1 & 2 are removed, consistent with the GENESYS model.
5. The version of GENESYS model used in the 2016 Resource Adequacy Assessment was introduced, with Colstrip 1 & 2 retirement, and winter SW imports increased to 3,400 MWs. Further details of the inputs into this version of GENESYS are discussed in Appendix G.
6. Updated forced outage rates for PSE thermals to be consistent with those filed in the most recent General Rate Case; the updated forced outage rates are slightly lower.

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

Impacts of Input Revisions to Incremental Capacity Needed to Meet 5 Percent LOLP

Figure N-25 shows the impacts of the key input revisions to the incremental capacity needed to meet the 5 percent LOLP.

Figure N-25: Impact of Key Input Revisions

	Revisions	MW Needed for 5% LOLP Oct 2020 - Sep 2021
2015 IRP Base	Regional Market Reliance Assumptions: SW Imports = 3,500 (+550), Carty 2 = +440, Grays Harbor out (-650), 2015 IRP Base Load Forecast w/ DSM	-116
2017 IRP Updates	Remove DSR	525
	F16 loads, no DSR	335
	Update existing resource capacities	300
	Update wind draws	300
	Remove Colstrip 1 & 2 from PSE portfolio, consistent with GENESYS	560
	Regional Market: 2016 GENESYS, SW Imports = 3,400, No Carty 2, Grays Harbor in, Colstrip 1 & 2 out	542
	New forced outage rates draws for PSE thermal fleet	550

The incremental capacity needed to achieve the 5 percent LOLP is 550 MW, on top of existing PSE resource capacity. This value is used in the calculation of planning margin below.

Calculation of Planning Margin and Resource Needs

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. The 5 percent LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.[4]

Using the LOLP methodology, we determined that we need 123 MW of resources by 2020. In order to establish this need, we went through three steps.

1. Use PSE's resource adequacy model (RAM) to find the capacity need for the period October 2020 – September 2021. The RAM is consistent with GENESYS, the resource adequacy model used by the Northwest Power and Conservation Council (NPCC or the Council). In the NPCC's GENESYS, Colstrip 1 & 2 are retired during this time period, so Colstrip 1 & 2 were retired in RAM as well. With Colstrip 1 & 2 retired, PSE needs 503 MW of resources by December 2020.
2. Determine the planning margin for a 503 MW need, with Colstrip 1 & 2 retired. This comes to 13.5 percent.
3. Using the 13.5 percent planning margin, Colstrip 1 & 2 were added back to the 503 MW need because they do not retire until 2022, so the resulting need for October 2020 – September 2021 is 123 MW.

STEP 1: USE RAM TO FIND CAPACITY NEED. This analysis looked at the likelihood that load will exceed resources on an hourly basis over the course of a full year. Included are uncertainties around temperature impacts on loads before conservation, hydro conditions, wind, and forced outage rates (both their likelihood and duration), and uncertainties in market reliance based on the Council's regional adequacy model, GENESYS. Because of PSE's large reliance on the market, it is important that PSE's resource adequacy analysis is consistent with the regional assessment of resource adequacy. This is a Monte Carlo simulation that consists of 6,160 draws that model different temperature conditions, hydro conditions and thermal forced outage rate assumptions. Each of the draws and study year are consistent for both models. This analysis resulted in the need for 503 MWs of additional resources to achieve a 5 percent LOLP in the study year October 2020 – September 2021.[5]

STEP 2: DETERMINE PLANNING MARGIN. Figure N-26 shows the calculation of the planning margin to achieve the adequate level of reliability. Given that PSE has a winter peaking load, any capacity brought in to meet the planning margin in the winter is also

4 / See http://www.nwcouncil.org/library/2008/2008-07.htm

5 / The 503 MW need is before including additional cost-effective conservation. We need to establish resource need first, and then we determine how much of that need would cost effectively be met by conservation.

available to meet capacity in other seasons. The 503 MW need in December 2020 was calculated with Colstrip Units 1 & 2 retired, consistent with the NPCC GENESYS assumptions. The 503 MW capacity need translates to a 13.5 percent planning margin, not including reserves.

Figure N-26: Planning Margin Calculation

	December 2020 w/o Colstrip 1 & 2
Peak Capacity Need from LOLP	503 MW
Total Resources (No DSR)	4,103 MW
Available Mid-C Transmissions	1,714 MW
	6,320 MW
Operating Reserves	(399) MW
	5,921 MW
BPA Loss Return	(71) MW
Peak Need	5,850
Normal Peak Load	5,156
Planning Margin (Peak Need/Peak Load)	13.5%

STEP 3: DETERMINE RESOURCE NEED WITH COLSTRIP 1 & 2. Since Colstrip Units 1 & 2 do not retire till mid-2022, we add its capacity back into the calculation (that is, subtract it from the 503 MW capacity need). This results in a capacity need in December 2020 of 123 MW. See Figure N-27, below, for peak need calculation. This is the reverse of figure N-26, above. In Figure N-26, we were trying to find the planning margin. Now, we know the planning margin is 13.5 percent, so we have reversed the calculation to find the peak need.

Figure N-27: December Peak Need in 2020, with Colstrip 1 & 2

	December 2020 w/ Colstrip 1&2
Peak Demand	5,153 MW
Planning Margin	13.5%
Normal Peak Load + PM	5,836 MW
Operating Reserves	415 MW
Total Capacity Need	6,251 MW
Total Resources (No DSR)	(4,401) MW
Available Mid-C Transmissions	(1,731) MW
Total	119 MW
Operating Reserves on new resources	15 MW
Total Resource Deficit/(Surplus)	123 MW

Effective Load Carrying Capability of Resources

The effective load carrying capability (ELCC) of a resource represents the capacity credit assigned to that resource. It is implemented in RAM since this value is highly dependent on the load characteristics and the mix of resources owned by a given utility. The ELCC or the peak contribution of any given resource is therefore unique for that utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of a gas-fired peaking plant, that would yield the same level of reliability. For resources such as a wind, solar, thermal resources, wholesale market purchases, or other energy limited resources such as batteries, demand response programs, and backup fuel for thermal resources, the ELCC is expressed as a percentage of the equivalent gas peaker capacity.

The ELCC value of any resource, however, is also dependent on the reliability metric being used for evaluating the peak contribution of that resource. This is a function of the characteristics of the resource being evaluated, and more importantly, what each of the reliability metrics is counting. For example, a variable energy resource such as wind or solar with unlimited energy may show different ELCC values depending on which reliability metric is being used – LOLP or EUE. LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occurred within each draw, and it ignores the duration and magnitude of the deficit events. EUE sums up all deficit MW hours across events and draws regardless of their duration and frequency expressed as average over the number of draws. In this study, we utilize LOLP as the reliability metric in estimating the ELCC of wind, solar and market purchases. However, we use EUE to determine the ELCC of energy-limited resources such as batteries, demand response and backup fuel for thermal plants, because LOLP is not able to distinguish the ELCC of batteries and demand response programs with different durations and call frequencies. EUE is also the reliability metric used to evaluate the ELCC of backup fuel storage since it is mainly limited by the total amount of storage.

WIND CAPACITY CREDITS. In order to implement the ELCC approach for wind in the RAM, the distribution of hourly generation for each of the existing and prospective wind farms was developed. These are described in the Stochastic Portfolio Model section of this appendix under the heading "Wind Generation." For the existing wind farms, the wind distributions were derived based on historical wind outputs. For new wind farms such as Skookumchuk or generic wind farms out of Montana or Washington, the wind distributions developed by DNV GL were used. Given these distributions, the wind farms were added into the RAM incrementally to determine the reduction in peaking plant capacity needed to achieve the 5 percent LOLP level. The wind farm's peak capacity credit is the ratio of the change in gas peaker capacity with and without the incremental wind capacity. The order in which the existing and prospective wind farms were added in the model follows the timeline of when these wind farms were acquired or about to be acquired by PSE: 1) Hopkins Ridge, 2) Wild Horse, 3) Klondike, 4) Lower Snake River, 5) Skookumchuck, which is a project currently under acquisition by PSE to serve its Green Direct customers, and finally 6) a generic wind resource expected to be located in eastern Montana, or a generic wind farm located in eastern Washington close to the Lower Snake River project, or a wind resource located offshore of Washington state. However, the ELCC values for the existing wind projects were not very different from each other, so a single ELCC value was assigned to the existing wind projects. Figure N-28 below shows the estimated peak capacity credit or ELCC of the wind resources included in this IRP.

Figure N-28: Peak Capacity Credit for Wind Resources

Wind Resources	Capacity (MW)	Equivalent Peaker Capacity Change to Get Back to 5% LOLP(MW)	Peak Capacity Credit Based on 5% LOLP
Existing Wind	823	90	**11%**
Skookumchuck Wind (DNV GL)	131.1	53	**40%**
Generic Eastern Montana Wind (DNV GL)	100	49	**49%**
Generic Washington Wind (DNV GL)	100	16	**16%**
Generic WA Offshore Wind (DNV GL)	100	51	**51%**

SOLAR CAPACITY CREDIT. The approach used to derive the ELCC of solar is the same approach used for wind. The hourly solar draws were based on the historical outputs of the 0.5 MW solar farm located near the Wild Horse wind project, and the outputs of that project were scaled to a 50 MW solar farm. The solar capacity credit is shown in Figure N-29 below. As expected, solar does not contribute to peaks because it is usually not available when the system loads are peaking early in the morning and late in the evening.

Figure N-29: Peak Capacity Credit of Solar Resources

Solar	Capacity (MW)	Equivalent Peaker Capacity Change to Get Back to 5% LOLP(MW)	Peak Capacity Credit Based on 5% LOLP
Solar	50	0	**0%**

WHOLESALE MARKET PURCHASES CAPACITY CREDIT. With the reliability of wholesale market purchases now reflected in PSE's RAM, we applied the same analytical process to estimate the capacity value of wholesale market purchases using LOLP as the reliability metric. The uncertainty in PSE's wholesale market capacity purchase volumes is based on the outputs of WPCM as described in Appendix G, which in turn is highly dependent on the results of the GENESYS model inputs and assumptions. The additional peaker needed to reach the 5 percent LOLP after introducing uncertainty in market purchases divided by the total market purchase capacity (which is the total Mid-C transmission availability) is the percent reduction in the peak contribution of market purchases from 100 percent. The ELCC of market purchases is therefore one (1) minus this percent reduction in market purchase reliability. Given the regional outage outputs from the GENESYS model used in the 2016 adequacy assessment, market purchases contribute almost 100 percent to PSE's peak requirements.

Figure N-30: Peak Capacity Credit for Wholesale Market Purchases

Market Purchases	Expected Capacity(MW)	Equivalent Peaker Capacity Change to Get Back to 5% LOLP(MW)	Peak Capacity Credit Based on 5% LOLP
Market Purchases	1,580	12	**99%**

BATTERY CAPACITY CREDIT. The estimated peak contribution of two types of batteries was modelled in RAM, each of which can be charged or discharged at a maximum of 25 MW per hour up to 4 hours duration when the battery is fully charged. When fully charged, each of the batteries can produce 100 MWh of energy continuously for 4 hours. Thus, the battery is energy limited. The two battery technologies are the lithium-ion battery with a round-trip efficiency of 85 percent, and the flow battery with a round-trip efficiency of 75 percent. The battery can be charged up to its maximum charge rate per hour only when there are no system outages and the battery is less than fully charged. The battery can be discharged up to its maximum discharge rate or just the amount of system outage, adjusted for its round-trip efficiency rating as long as there is a system outage and the battery is not empty.

As stated previously, the LOLP is not able to distinguish the impacts of the two types of batteries on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using the expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the battery technologies is then added to the portfolio, which leads to lower EUE. The amount of peaker capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the battery after adding the battery determines the peak capacity credit or ELCC of the battery. Since the only difference between the two battery technologies is their round-trip efficiency, we should expect a lower peak capacity contribution or ELCC for the battery with the lower round-trip efficiency. The estimated peak contribution of the two types of batteries is shown in Figure N-31.

Figure N-31: Peak Capacity Credit for Battery Resources

Battery	Capacity(MW)	Capacity Adjustment to Get EUE @ 5% LOLP(MW)	Peak Capacity Credit Based on EUE @ 5% LOLP
Lithium-ion, 4Hr, 25MW max per hr	25	22	**88%**
Flow Battery, 4Hr, 25MW max per hr	25	19	**76%**

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response (DR) program is also estimated using EUE, since this resource is also energy limited like batteries. Even for similarly sized DR programs, each program is expected to have different capacity contribution estimates depending on how each one is designed in terms of its duration and frequency of calls within a day and season.

While using EUE as the risk metric in estimating the peak contribution or ELCC of DR, the analysis approach is slightly different and uses the following steps:

1. Calculate the EUE of the portfolio at 5 percent LOLP.
2. Remove 100 MW of peaker capacity and calculate the total incremental EUE from Step 1.
3. Implement a DR program with given attributes.
4. Calculate the reduction in incremental EUE due to the DR program.
5. The ELCC of the given DR program is the ratio of the reduction in incremental EUE (Step 4) and the total incremental EUE (Step 2).

Note that only the characteristics of the incremental EUE identified in Step 2 above is the benchmark that we use to determine the ELCC of a similarly sized (100 MW) DR program. The incremental outages as a result of removing 100 MW of peaker capacity can be described by the following characteristics: magnitudes (incremental MW deficits), frequency (how often bad events happen in a day/season), duration (length in hours of bad events) and time between bad events. The ELCC of a similarly sized DR program is therefore highly dependent in its ability to address these characteristics of the incremental outage events.

When PSE issued its initial RFP for DR, program designs were based on what was observed across the country where DR is to be called on once a day in a 4-hour period to avoid customer fatigue. However, this once-a-day DR program is more appropriate to areas that are typically summer peaking, since they experience only one peak per day. After the RFP, PSE considered further refinements to its program design to address the double-peak shape of PSE loads during typical winter season days. The charts below illustrate the double-peak nature of PSE's daily loads, and the impacts of removing 100 MW of peaker capacity from the portfolio.

Figure N-32: PSE Winter Season Double Peaks

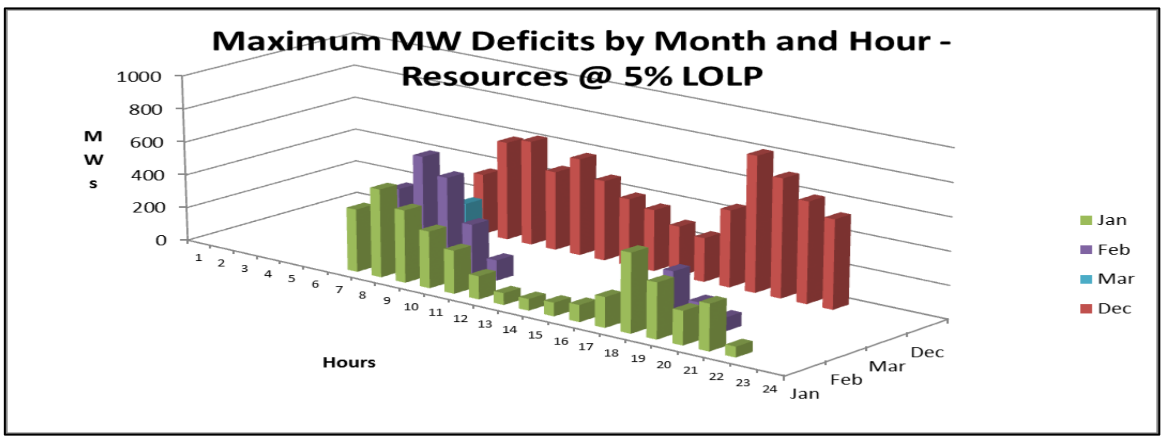
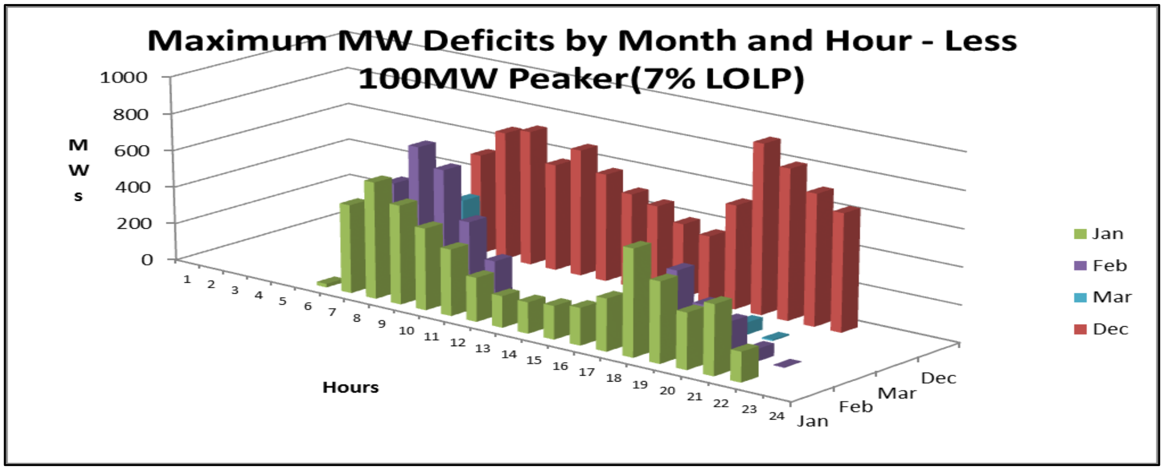


Figure N-33: PSE Winter Season Double Peaks, Minus 100 MW Peaker



When the 100 MW of peaker capacity is removed from the portfolio, not only are existing bad events made worse by higher MW deficits and longer outage durations, but new hours experience bad events as well. While not shown in these charts, the time in between bad events can be shorter also. To understand the effectiveness of DR program to meet peak loads, different combinations of DR parameters (duration in hours and call frequency within the day) are analyzed for their ability to mitigate the incremental outages resulting from the removal of a 100 MW peaker. The table below shows the ELCC or peak contribution of DR programs with different attributes, both duration the frequency of calls in a day. For the IRP, the DR program modeled was for a 3-hour maximum duration that can be called every 3 times a day or every 6 hours.

Figure N-34: Peak Capacity Credit for Demand Response Programs

ELCC Estimates for Various DR Event Parameters(100MW)					
	Call Frequency(Elapsed Hrs After Last Event)				
Duration(Hrs)	4	6	8	12	24
2	63%	61%	57%	49%	
3	80%	77%	72%	59%	
4	90%	85%	80%	65%	53%
5	94%	89%	84%	68%	55%

BACKUP FUEL CAPACITY CREDIT. PSE has relied on spot gas supply to operate its fleet of peakers, combined with a 48-hour fuel oil backup in lieu of more expensive firm gas supply contracts, since the peakers have low capacity factors. Two key issues arise from this reliance on 48-hour fuel oil backup:

1. Is the current 48-hour fuel oil backup adequate to run the peakers if spot gas is not available for the season?
2. If backup fuel oil is used for the season, does PSE exceed the annual maximum run hours constraint of 300 hours required to meet air emission standards?

Currently, PSE stores about 48 hours of fuel oil backup for each peaker with the total amount varying depending on the capacity of the peaker. This enables the peaker to run for a cumulative 48 hours within the season without fuel replenishment since replenishment within the season is usually expensive. PSE's peaker fleet consists of Fredonia Units 1-4, Whitehorn Units 1 & 2, and Frederickson Units 1 & 2 for a total of 696 MW of maximum capacity (temperature adjusted). In PSE's RAM, these units are assumed to be supplied with gas from the spot market with no risks to their availability. To analyze the adequacy of the 48-hour fuel oil backup, we looked at the case in which the fuel oil backup is not available AND the market is unable to provide spot gas for the entire season. Under these circumstances the entire peaker fleet is not available in the resource adequacy model, which leads to more frequent and severe outage events. The MWhs of outages resulting from the absence of the peakers are then summed up for the season. Then, the sum of MWhs that the 48-hour fuel oil backup is able to provide is compared with the MWhs of outages resulting from the absent peakers in the resource adequacy model. If the MWhs from the 48-hour fuel oil backup is greater than the sum of MWhs from being unable to run the peakers, then we can conclude that the 48-hour fuel oil backup is adequate.

Note that the relevant MWh outages include only those from the incremental outages in the resource adequacy model, which results in some outage events 5 percent of the time since it is based on the 5 percent LOLP reliability standard. Also, to avoid inflating the MWh outages, this analysis included the impacts of conservation based on the 2015 IRP.

Since the resource adequacy model is also able to identify and count the incremental hours when new outage events occur, we also sum up all of the hours for the incremental outages to determine if this exceeds the maximum allowed run hours for fuel oil according to current air emission standards.

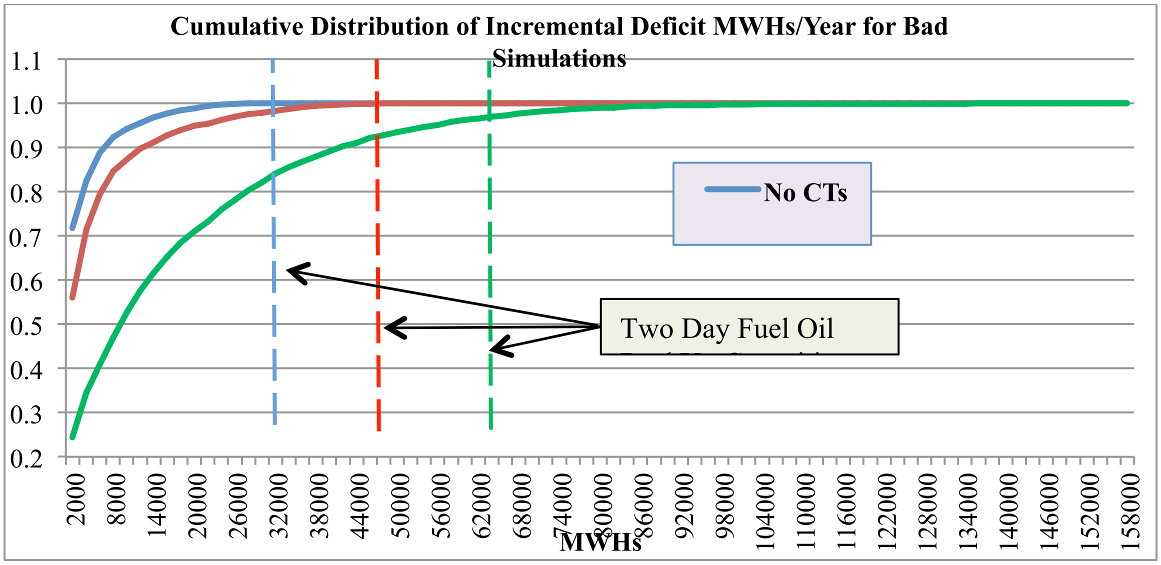
To determine if the results of the analysis are invariant to the scale of the capacity that is not available to meet resource adequacy, three scenarios were examined.

SCENARIO 1. Remove all existing peakers (696 MWs)
SCENARIO 2. Scenario 1, plus remove Colstrip Units 1 & 2 (298 MWs) and assume that peakers replace Colstrip 1 & 2 for a total of 994MWs
SCENARIO 3. Scenario 2, plus remove Colstrip 3 & 4 (359 MWs) and assume peakers replace Colstrip 3 & 4 for a total of 1,353 MWs

The resource adequacy model is run under each of the three scenarios and the resulting incremental outages are examined both for MWH outages and hours of outages. Because RAM is a stochastic model over 6,160 draws, both the MWH outages and hours of outages are presented as a cumulative distribution, and compared to the thresholds for the 48-hour fuel oil backup and maximum run hour constraints, respectively.

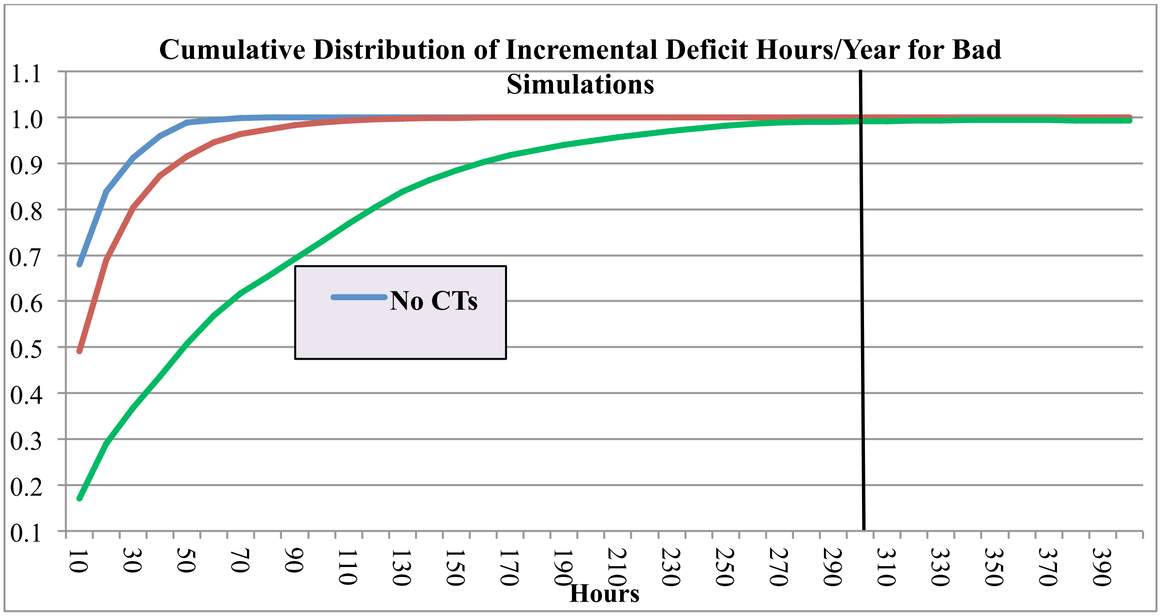
The chart below shows the cumulative distribution of MWHs resulting from the incremental outage events for each of the three scenarios. The higher the level of capacity that is unable to run due to the lack of gas supply, the greater the amount of deficit MWHs. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the cumulative MWHs that the peakers are able to supply with the 48-hour fuel oil backup. For scenarios 1 and 2, where the peaker capacity level goes up to almost 1,000 MWs, the 48-hour fuel oil back is adequate to cover 100 percent of the deficit MWHs resulting from the incremental outage events. When the peaker capacity level that is not able to operate goes up to 1,353 MWs, the 48-hour fuel oil back is only able to cover about 97 percent of all the deficit MWHs. For PSE’s current fleet of peakers, the study results show that the 48-hour fuel oil backup is adequate.

Figure N-35: Fuel Oil Backup, Cumulative Distribution of Incremental Deficits, MWh for Bad Simulations



The next chart displays the cumulative distribution of the run hours where incremental outage events occur for each of the three scenarios. Again, the higher the amount of peaker capacity that is not able to operate due to the lack of spot gas supply, the greater the amount of deficit events, so the cumulative distribution curve shifts to the right. The vertical line shows the 300 maximum run hours in a season required by current air emission standards. This chart illustrates that the maximum 300 run hours constraint is always greater than the 100 percent level of cumulative hours experiencing outage events for all of the scenarios tested in this study. This implies that for the existing PSE peaker fleet, or even with potential additions to the fleet, the 48-hour fuel oil backup meets the air emission standard for maximum run hours.

Figure N-36: Fuel Oil Backup, Run Hours Constraints



4. OUTPUTS: AVOIDED COSTS

AURORA Electric Prices and Avoided Costs

Consistent with WAC 480-107-055 (4), the schedules of estimated avoided costs in this section provide only general information about the costs of new power supplies – it should not be interpreted as a guaranteed contract price for electricity. This section includes estimated capacity costs consistent with the resource plan forecast, along with the different market price forecasts from AURORA. The two kinds of avoided costs – avoided capacity costs and avoided energy costs – are discussed below.

Avoided Capacity Costs

Within the category of avoided capacity costs, there are two types: avoided resource costs, and avoided supply-related costs.

AVOIDED CAPACITY RESOURCE COSTS: Avoided resource costs are directly related to avoiding acquisition of new capacity resources. The timing and cost of avoided capacity resources are tied directly to the resource plan. This represents the average cost of capacity additions (or average incremental costs) not marginal costs.

The indicative avoided capacity resource costs shown in Figure N-37, below, are "net" capacity costs, meaning that the energy or other resource values have been deducted, using the Base + CAR Only Scenario. For example, frame peakers can dispatch into market when the cost of running the plant is less than market, which creates a margin that flows back to reduce customers' rates. The peaker costs shown in this table are net of those margins – they represent the cost of the plant that will not be covered by the energy market operations. The avoided peaker costs increase over time. This is to ensure a capacity resource acquired earlier in the planning horizon is credited with avoiding more expensive resources in the future. With batteries, we also deducted the sub-hourly flexibility value in the calculation of net avoided capacity cost. Before 2022, Figure 1-37 also includes the Avoided Short-term Supply-related Capacity Cost, which is described in the section below.

In addition to the avoided capacity cost expressed in $/kW-yr, the capacity credit of different kinds of resources needs to be specified. After specifying the annual avoided capacity resource costs by year, Figure N-37 includes indicative adjustments to peak capacity value from the effective load carrying capability (ELCC) analysis in this IRP. The ELCC for a firm, dispatchable resource would be 100 percent, but different kinds of intermittent resources would have different peak capacity contributions. The capacity contributions used here are consistent with those described in Chapter 6.

AVOIDED SHORT-TERM SUPPLY-RELATED CAPACITY COSTS. PSE depends on short-term market purchases over existing firm transmission to meet a significant portion of our customers' peak capacity need. Annually, as PSE approaches the heating season, we examine how much of the peak need has already been covered by financial hedges to manage energy cost risk. To the extent that the capacity of those hedges falls short of covering the peak need, PSE will physically hedge most of the remaining capacity.

There are a variety of ways to cover this outstanding physical position. The easiest to conceptualize is a physical call-option contract, where PSE would pay a counter-party to provide energy during the winter at either a fixed or indexed price. The value is small – approximately $0.10/kW-yr – based on recent market experience. Avoided Short-term Supply-related Capacity Cost applies to resources not delivered to PSE's system, but to a location where PSE has firm transmission to transmit the power to our customers. These avoided costs also apply during periods before PSE has a need for supply-side resources – see Figure N-38, Avoided Short-term Supply-related Capacity Costs, below.

Figure N-37: Indicative Avoided Capacity Resource Costs for Resources Delivered to PSE (Base + CAR Only Scenario)

	Capacity Resource Addition	Levelized Net Cost ($/kw-yr)	Firm Resource ELCC = 100% ($/kw-yr)	Wind Resource ELCC = 16% ($/kw-yr)	Solar Resource ELCC = 1% ($/kw-yr)
2018	Avoided Energy Supply Capacity Cost	$0.10	$0.10	$0.02	$0.00
2019		$0.10	$0.10	$0.02	$0.00
2020		$0.10	$0.10	$0.02	$0.00
2021		$0.10	$0.10	$0.02	$0.00
2022	Transmission Redirect	$3.26	$3.26	$0.52	$0.03
2023	Flow Battery-4 hr	$93.00	$93.00	$14.88	$0.93
2024	Flow Battery-4 hr	$93.00	$93.00	$14.88	$0.93
2025	Frame Peaker	$80.00	$80.00	$12.80	$0.80
2026	Frame Peaker	$80.00	$80.00	$12.80	$0.80
2027	Frame Peaker	$80.48	$80.48	$12.88	$0.80
2028		$80.48	$80.48	$12.88	$0.80
2029		$80.48	$80.48	$12.88	$0.80
2030		$80.48	$80.48	$12.88	$0.80
2031	Frame Peaker	$84.16	$84.16	$13.47	$0.84
2032		$84.16	$84.16	$13.47	$0.84
2033		$84.16	$84.16	$13.47	$0.84
2034	Frame Peaker	$88.31	$88.31	$14.13	$0.88
2035		$88.31	$88.31	$14.13	$0.88
2036	Frame Peaker	$91.09	$91.09	$14.57	$0.91
2037		$91.09	$91.09	$14.57	$0.91

Figure N-38: Indicative Short-term Supply-related Avoided Capacity Costs for Resources Not Delivered to PSE, but to a Location from Which PSE Has Firm Transmission (Base + CAR Only Scenario)

	Capacity Resource Addition	Levelized Net Cost ($/kw-yr)	Firm Resource ELCC = 100% ($/kw-yr)	Wind Resource ELCC = 16% ($/kw-yr)	Solar Resource ELCC = 1% ($/kw-yr)
2018	Avoided Energy Supply Capacity Cost	$0.10	$0.10	$0.02	$0.00
2019		$0.10	$0.10	$0.02	$0.00
2020		$0.10	$0.10	$0.02	$0.00
2021		$0.10	$0.10	$0.02	$0.00
2022		$0.10	$0.10	$0.02	$0.00
2023		$0.10	$0.10	$0.02	$0.00
2024		$0.10	$0.10	$0.02	$0.00
2025		$0.10	$0.10	$0.02	$0.00
2026		$0.10	$0.10	$0.02	$0.00
2027		$0.10	$0.10	$0.02	$0.00
2028		$0.10	$0.10	$0.02	$0.00
2029		$0.10	$0.10	$0.02	$0.00
2030		$0.10	$0.10	$0.02	$0.00
2031		$0.10	$0.10	$0.02	$0.00
2032		$0.10	$0.10	$0.02	$0.00
2033		$0.10	$0.10	$0.02	$0.00
2034		$0.10	$0.10	$0.02	$0.00
2035		$0.10	$0.10	$0.02	$0.00
2036		$0.10	$0.10	$0.02	$0.00
2037		$0.10	$0.10	$0.02	$0.00

Avoided Energy Costs

All of the resources in PSE's resource plan are capacity resources, not energy resources. Redirected transmission, batteries and peakers all rely on market purchases for energy. Therefore, PSE's avoided energy costs are clearly avoiding Mid-C market purchases. Peakers are capable of generating energy, so they temper PSE's exposure to market prices, at least when market heat rates (the spread between natural gas prices and power prices) increase. This means using a forecast of market prices could tend to overstate avoided energy costs during some hours – but only for short periods.

The following tables include the forecast average monthly power prices and forecast average annual market power prices at Mid-C for all of the scenarios. The first table, Figure N-39, includes the Mid-C market prices forecast for the Base + CAR Only Scenario. This is the set of avoided energy costs PSE suggests would be the most informative for potential suppliers. While the future of the CAR is uncertain, it is a policy that is currently in effect.

Base Scenario prices are shown in the second table, Figure N-40. The Base Scenario includes CAR in the early years, but then transitions to the CPP in 2022, assuming the CPP is implemented as a WECC-wide cap and trade regulation that could significantly affect Mid-C prices. Whether the CPP will be implemented at all is highly uncertain. There are currently no serious efforts to develop a WECC-wide, interstate carbon market to implement the CPP. For any sizable power contracts, suppliers should not expect PSE would commit its customers to pay a market price for power that includes carbon prices associated with policies and regulatory structures that do not exist. The Base Scenario prices, however, are helpful in understanding the range of what market price could be in the future, along with the prices in all the other scenarios, which are included in the following tables.

Figure N-39: Forecast Mid-C Power Prices for Base + Mid CAR Only Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
							MONTHS						
2018	31.15	30.89	28.82	24.41	21.65	21.62	27.89	30.19	29.94	28.71	27.51	28.55	27.61
2019	29.74	29.29	27.64	24.91	22.72	22.27	28.21	30.56	30.94	30.06	27.69	28.56	27.71
2020	29.43	29.29	27.73	24.87	22.28	22.85	28.93	31.15	32.15	32.05	29.66	29.67	28.34
2021	31.21	31.27	28.91	26.02	23.36	23.82	30.12	32.71	33.52	32.18	30.92	31.16	29.60
2022	32.93	33.33	30.47	28.53	26.57	27.44	33.04	35.96	36.82	35.98	34.72	33.90	32.47
2023	35.13	35.81	32.66	30.36	29.13	29.90	35.64	38.62	39.51	40.79	38.79	36.94	35.27
2024	37.01	38.62	35.08	32.71	31.51	31.58	37.99	41.65	42.97	42.20	39.46	39.45	37.52
2025	40.60	41.97	38.71	36.91	35.43	34.92	42.20	45.57	46.80	45.86	43.18	43.15	41.27
2026	44.87	46.21	43.40	39.90	37.40	38.11	45.93	49.72	50.61	51.14	47.81	46.97	45.17
2027	47.85	49.28	46.31	42.70	40.10	40.75	48.68	52.68	53.42	52.98	50.37	49.78	47.91
2028	50.87	51.89	48.99	46.13	44.44	43.97	51.72	56.10	56.36	56.78	54.59	52.87	51.23
2029	53.83	55.67	51.83	48.25	45.85	45.23	54.83	59.55	60.06	60.20	57.05	55.80	54.01
2030	56.83	58.50	53.86	50.80	47.73	46.09	57.40	61.82	63.06	62.38	59.30	59.14	56.41
2031	59.84	61.59	56.73	54.49	51.47	49.09	60.71	65.32	66.79	65.83	63.11	62.63	59.80
2032	63.34	64.33	60.11	56.58	52.37	52.84	63.69	69.04	70.32	70.13	68.21	66.37	63.11
2033	66.96	67.97	62.83	60.23	56.59	55.91	66.95	72.51	73.42	72.30	70.45	69.25	66.28
2034	69.65	70.23	64.08	61.88	59.32	56.67	68.85	74.71	75.56	74.83	73.17	71.72	68.39
2035	72.45	73.49	67.78	64.22	59.37	57.05	71.53	78.53	80.06	78.72	76.81	75.44	71.29
2036	75.00	76.00	69.85	66.30	60.46	58.88	73.76	80.59	83.10	80.47	78.50	78.47	73.45
2037	77.57	78.09	71.78	68.66	63.78	60.56	75.52	82.63	85.24	82.37	81.49	81.18	75.74

Figure N-40: Forecast of Mid-C Power Prices for Base Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	31.02	30.80	28.80	24.44	21.83	21.77	27.92	30.12	29.94	28.81	27.63	28.68	27.65
2019	29.82	29.36	27.64	24.89	22.78	22.48	28.21	30.47	31.04	30.12	27.79	28.66	27.77
2020	29.65	29.37	27.76	24.92	22.46	23.11	28.97	31.21	32.23	32.11	29.75	29.84	28.45
2021	31.43	31.38	28.97	26.04	23.42	23.91	29.94	32.61	33.57	32.44	31.12	31.31	29.68
2022	36.86	36.35	33.15	30.27	29.17	30.36	34.56	38.16	38.37	36.32	36.90	37.18	34.80
2023	38.30	38.27	35.68	32.95	31.11	33.17	37.01	41.00	41.18	41.00	40.35	39.74	37.48
2024	39.95	40.65	38.50	36.48	33.48	34.89	39.75	44.07	45.52	42.62	42.00	42.11	40.00
2025	43.29	43.78	41.95	40.32	37.43	38.84	43.41	48.14	49.55	46.50	45.63	45.85	43.72
2026	46.78	47.27	45.37	42.60	40.22	42.20	46.61	51.50	52.91	51.09	49.63	49.17	47.11
2027	49.92	50.38	48.56	46.20	43.10	45.12	49.52	54.85	56.04	53.38	52.66	52.29	50.17
2028	53.54	53.81	51.54	49.49	47.04	48.31	52.82	58.81	59.25	57.21	57.24	56.48	53.79
2029	57.70	58.41	55.22	52.61	49.40	50.86	56.19	62.59	64.07	61.98	61.07	60.47	57.55
2030	61.38	61.95	57.93	55.35	52.05	52.79	58.71	65.04	67.36	64.59	63.67	64.03	60.40
2031	64.56	65.10	61.56	58.92	55.73	56.28	62.52	68.72	71.35	68.61	67.88	68.02	64.10
2032	68.73	68.90	65.70	62.07	58.45	60.65	66.75	73.95	76.32	74.34	74.62	73.45	68.66
2033	72.80	73.42	69.49	65.82	62.44	63.56	70.21	78.06	79.97	77.20	77.80	77.14	72.33
2034	77.16	77.45	71.23	67.81	64.61	65.12	72.38	79.93	81.54	79.67	80.54	79.52	74.75
2035	79.13	79.93	74.68	70.86	66.07	66.59	74.95	83.57	85.48	83.61	84.61	83.04	77.71
2036	82.13	82.62	77.22	73.54	67.82	68.82	78.04	86.01	88.86	85.69	86.28	86.20	80.27
2037	85.20	85.67	80.17	76.30	71.24	71.19	81.19	88.68	91.90	88.48	89.74	89.39	83.26

Figure N-41: Forecast of Mid-C Power Prices for Base + No CO_2 Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
							MONTHS						
2018	30.02	29.53	28.15	22.97	19.45	19.01	25.33	28.93	28.48	26.16	26.72	27.90	26.05
2019	28.79	28.19	26.87	23.78	20.29	19.49	25.55	29.33	29.12	26.73	26.90	27.88	26.08
2020	28.76	28.31	26.95	23.44	19.89	19.95	26.23	29.88	30.19	28.49	28.20	29.02	26.61
2021	30.17	29.51	27.98	24.12	20.68	20.66	27.04	31.20	31.02	28.48	29.03	30.27	27.51
2022	31.71	31.34	29.51	27.25	24.16	24.09	30.31	34.21	33.85	31.52	31.88	32.48	30.19
2023	33.02	33.10	31.17	29.32	26.89	27.06	32.81	36.73	36.22	35.97	35.70	35.40	32.78
2024	34.96	35.31	32.78	31.78	29.55	29.27	35.36	39.42	39.81	37.85	37.34	37.79	35.10
2025	38.67	38.81	36.46	35.60	32.97	31.98	39.08	43.44	43.81	41.81	41.22	41.77	38.80
2026	42.70	43.15	40.25	38.42	34.33	33.93	42.31	47.33	47.68	46.99	45.42	45.09	42.30
2027	45.72	46.05	43.11	41.43	36.83	36.49	45.12	50.22	50.42	49.11	47.95	47.83	45.02
2028	48.67	48.99	45.65	44.22	40.79	39.36	48.10	53.39	53.13	52.59	51.46	50.73	48.09
2029	51.58	52.47	48.84	46.73	42.57	41.56	50.71	56.60	57.10	56.12	54.32	53.88	51.04
2030	54.78	55.17	51.28	49.00	44.06	42.44	52.28	59.03	60.06	58.90	56.82	57.37	53.43
2031	57.81	58.36	54.34	52.08	47.40	45.23	55.31	62.10	63.49	62.19	60.66	60.96	56.66
2032	61.29	61.26	57.81	54.15	48.76	49.00	58.80	65.34	66.70	66.18	65.68	64.73	59.97
2033	64.88	65.05	60.54	57.63	52.68	51.53	61.60	68.43	69.54	68.30	68.11	67.58	62.99
2034	67.58	67.44	61.66	59.04	54.94	52.25	63.06	70.35	71.51	70.85	70.55	69.90	64.93
2035	70.48	70.71	65.55	61.13	55.28	53.14	65.18	73.69	75.84	74.97	74.37	73.81	67.85
2036	72.98	73.00	67.43	62.78	56.50	54.63	67.35	75.53	78.59	76.82	76.26	76.68	69.88
2037	75.17	75.37	69.42	64.96	59.20	56.33	68.80	77.26	80.50	78.68	79.13	79.07	71.99

Figure N-42: Forecast of Mid-C Power Prices for Low Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	25.96	25.60	23.78	19.94	17.25	17.49	23.19	25.38	24.51	22.53	21.95	23.53	22.59
2019	24.22	23.66	22.18	19.99	17.93	17.51	22.22	24.97	24.61	22.95	21.79	22.66	22.06
2020	23.54	23.35	21.81	19.48	16.97	17.54	22.28	24.94	25.18	23.71	22.53	22.95	22.02
2021	23.63	23.55	22.24	19.55	17.41	18.13	22.64	25.38	25.27	23.31	22.73	24.02	22.32
2022	24.32	24.21	22.30	20.56	18.24	18.15	23.20	27.45	26.55	23.66	24.61	25.58	23.24
2023	26.13	26.06	24.29	22.17	20.18	20.30	25.16	29.31	28.48	26.98	27.73	27.67	25.37
2024	27.41	27.81	25.94	24.13	21.85	21.89	26.90	31.06	31.12	28.18	29.29	30.21	27.15
2025	30.46	31.05	29.82	28.05	25.29	24.81	30.46	34.92	35.55	32.73	33.45	33.51	30.84
2026	34.05	35.03	32.62	29.06	25.96	26.12	31.99	37.16	37.87	35.43	35.32	34.70	32.94
2027	35.07	36.08	33.09	29.96	26.61	26.53	32.32	37.95	38.53	35.94	36.27	35.59	33.66
2028	36.17	37.12	34.35	31.31	28.13	27.40	33.41	39.44	39.67	37.39	37.82	36.81	34.92
2029	37.23	39.03	35.81	32.08	28.83	28.69	34.79	41.43	42.47	40.15	39.12	38.37	36.50
2030	38.99	40.72	37.67	33.87	30.46	29.57	36.05	43.04	45.18	42.40	41.36	40.97	38.36
2031	41.87	43.85	40.76	37.32	33.55	31.96	39.26	46.22	48.84	45.93	45.06	44.69	41.61
2032	44.87	46.58	42.67	39.31	34.73	35.02	42.25	49.09	51.15	48.97	49.32	47.65	44.30
2033	47.01	48.21	43.74	40.73	36.74	36.09	43.72	51.12	52.72	49.74	50.54	49.28	45.80
2034	48.76	49.60	43.64	40.40	37.32	35.23	43.33	51.28	53.47	50.84	51.39	49.83	46.26
2035	49.53	51.35	45.55	40.36	36.11	34.46	43.45	52.91	56.34	53.26	53.39	51.34	47.34
2036	50.47	52.24	46.21	40.66	36.21	34.70	44.38	53.25	57.99	54.06	53.64	52.61	48.04
2037	51.66	53.53	47.07	41.76	37.92	35.33	45.52	54.25	59.37	55.11	55.40	53.89	49.23

Figure N-43: Forecast of Mid-C Power Prices for High Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
							MONTHS						
2018	32.31	32.56	30.28	25.62	23.69	23.74	29.94	32.27	32.20	30.90	30.32	31.20	29.59
2019	41.92	40.94	35.03	31.00	28.17	26.93	34.00	36.80	36.73	36.23	34.20	34.72	34.72
2020	36.58	36.41	33.28	29.23	26.94	27.17	33.80	36.39	37.14	37.10	35.62	35.34	33.75
2021	38.57	38.20	34.02	29.75	27.53	27.97	34.52	37.50	38.19	37.09	38.06	39.07	35.04
2022	44.24	43.09	39.48	36.25	35.35	36.91	41.54	45.64	45.88	44.63	47.20	48.30	42.38
2023	49.55	49.02	45.00	41.05	40.10	41.57	47.16	51.34	51.33	51.75	52.46	51.75	47.67
2024	50.78	51.39	47.45	43.97	41.41	42.29	48.98	53.95	54.54	52.13	52.81	53.94	49.47
2025	57.86	58.33	54.47	51.66	48.65	49.19	56.77	61.85	62.16	59.97	60.48	61.17	56.88
2026	61.59	62.17	57.18	53.19	50.25	51.63	59.15	64.78	65.52	64.43	64.23	63.98	59.84
2027	63.93	64.21	59.15	55.80	52.04	53.26	61.45	67.31	67.47	64.80	66.11	66.08	61.80
2028	68.90	68.56	63.57	59.44	56.47	56.30	65.47	71.88	70.89	69.17	71.06	70.83	66.05
2029	78.86	79.54	72.52	67.75	64.63	65.39	74.76	82.11	82.23	81.29	83.93	84.59	76.47
2030	85.47	86.13	79.57	76.08	73.18	73.51	82.48	89.32	90.99	90.09	96.50	97.42	85.06
2031	86.03	86.37	80.97	78.14	74.72	74.97	83.78	90.44	92.33	91.20	96.70	98.16	86.15
2032	89.54	88.96	83.71	80.38	76.08	78.71	86.96	94.20	95.86	95.52	99.54	99.27	89.06
2033	93.80	93.13	88.86	85.53	82.00	82.93	91.29	99.10	101.04	100.27	113.90	114.02	95.49
2034	99.89	99.32	91.98	88.37	85.00	84.21	93.31	100.91	102.74	100.99	104.05	103.25	96.17
2035	98.68	98.63	94.90	87.31	82.45	82.06	91.33	100.03	102.67	100.49	100.08	99.66	94.86
2036	101.30	100.90	96.81	89.25	84.16	84.41	93.75	101.53	105.27	102.25	101.26	102.40	96.94
2037	103.96	103.20	98.79	91.65	87.41	86.79	95.95	103.88	107.59	104.46	104.28	105.01	99.41

Figure N-44: Forecast of Mid-C Power Prices for Low Demand + High Gas CO_2 Scenario (Nominal \$/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	29.44	29.57	28.53	24.73	21.37	20.85	27.85	30.78	30.79	28.79	28.26	28.73	27.47
2019	38.30	37.85	33.26	29.87	25.51	24.34	31.46	34.98	35.07	33.62	31.78	32.22	32.36
2020	33.12	33.01	31.64	27.93	23.96	23.65	30.66	34.41	34.84	34.05	32.57	32.74	31.05
2021	33.90	33.73	32.11	28.23	24.09	23.96	31.32	35.49	35.85	33.67	33.36	35.06	31.73
2022	41.07	40.07	37.73	34.90	33.67	34.87	39.04	42.92	43.12	40.92	43.56	44.23	39.68
2023	45.55	45.41	42.34	39.54	38.27	38.84	43.91	47.96	48.12	47.91	48.90	47.88	44.55
2024	46.56	47.16	44.15	41.36	39.43	40.03	44.72	49.05	50.24	48.05	49.12	49.39	45.77
2025	52.72	53.52	50.10	48.02	45.36	45.41	51.65	55.91	57.26	55.87	56.11	56.10	52.34
2026	55.29	55.99	52.08	49.16	46.31	47.65	53.10	57.54	59.02	58.09	58.26	57.67	54.18
2027	57.17	57.56	53.58	51.10	48.20	48.87	54.45	59.02	60.10	58.24	59.74	59.33	55.61
2028	61.36	61.34	57.55	54.36	51.81	51.01	57.16	62.61	63.35	61.60	64.07	63.30	59.13
2029	70.12	71.17	65.44	61.67	58.42	58.84	66.31	72.15	73.89	73.61	76.34	75.32	68.61
2030	75.76	77.49	71.49	67.99	65.19	65.09	73.46	79.02	81.70	82.16	86.66	85.70	75.98
2031	77.59	78.70	73.68	70.82	68.22	67.10	75.89	81.52	84.38	84.47	87.88	87.29	78.13
2032	81.42	81.79	76.51	72.78	69.27	70.87	79.80	86.58	89.63	89.96	92.08	89.38	81.67
2033	85.66	86.18	81.45	77.11	74.02	74.81	84.20	91.81	95.31	94.83	104.80	102.54	87.73
2034	91.98	92.68	85.40	81.47	79.29	77.77	88.08	95.61	98.59	96.98	97.37	94.91	90.01
2035	92.18	93.51	88.95	83.27	79.19	77.66	88.68	96.62	100.48	98.42	95.43	93.26	90.64
2036	95.18	96.30	91.55	85.51	81.29	80.36	91.52	99.27	104.11	100.57	97.02	96.31	93.25
2037	98.25	99.19	94.35	88.61	85.22	83.04	94.16	102.12	107.21	103.56	100.34	99.33	96.28

Figure N-45: Forecast of Mid-C Power Prices for Base + Low Gas Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	26.85	26.34	24.14	20.03	18.05	18.40	24.36	26.49	25.94	25.14	23.08	24.14	23.58
2019	25.47	25.14	22.63	20.08	18.61	18.60	24.05	26.25	26.51	25.77	23.45	23.86	23.37
2020	24.96	25.11	22.21	19.71	17.85	18.81	24.17	26.47	27.38	27.34	24.50	24.16	23.56
2021	25.29	25.45	22.89	19.98	18.40	19.21	24.24	26.98	27.97	26.82	25.16	25.29	23.97
2022	31.24	30.55	28.13	25.30	23.46	24.94	28.83	32.97	33.59	31.40	32.23	32.52	29.60
2023	33.42	33.05	30.35	27.70	25.32	27.13	31.29	35.63	35.72	35.55	35.46	34.52	32.09
2024	34.40	35.17	33.04	30.14	26.69	27.90	33.59	38.20	39.26	36.73	36.50	37.04	34.05
2025	37.18	38.19	37.14	34.91	31.42	32.81	38.19	42.46	44.01	40.89	40.21	40.62	38.17
2026	41.05	41.80	39.81	36.45	33.60	35.46	40.09	44.65	46.35	43.83	42.88	42.21	40.68
2027	42.84	43.41	41.04	37.98	34.81	36.71	41.54	46.44	47.51	44.52	44.36	43.41	42.05
2028	44.47	45.06	42.64	39.93	37.20	38.30	43.42	49.03	49.01	46.64	46.39	45.45	43.96
2029	46.35	47.19	44.69	41.85	38.18	39.68	45.69	51.55	52.60	49.92	48.65	47.72	46.17
2030	49.25	49.90	47.57	44.49	40.85	42.14	48.59	54.46	56.29	52.62	51.01	51.35	49.04
2031	52.99	53.49	51.45	48.89	44.88	45.76	52.97	58.50	60.51	56.63	55.29	55.85	53.10
2032	56.62	57.34	54.18	51.24	46.91	49.38	56.46	62.43	63.60	60.76	60.10	59.68	56.56
2033	59.13	59.32	55.80	53.16	48.63	50.79	58.05	64.43	65.34	62.39	62.16	61.88	58.42
2034	62.02	61.61	55.92	53.34	49.65	50.65	58.35	65.45	65.86	62.55	63.11	62.43	59.24
2035	62.73	62.69	57.66	53.83	49.82	50.61	59.44	67.73	68.61	64.69	64.87	64.01	60.56
2036	63.86	63.75	58.77	54.91	50.65	51.60	61.02	68.51	70.44	64.94	65.00	65.56	61.58
2037	65.06	64.79	59.60	56.13	52.68	52.75	62.00	69.62	71.31	65.61	66.54	66.73	62.74

Figure N-46: Forecast of Mid-C Power Prices for Base + High Gas Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
							MONTHS						
2018	30.61	30.45	28.94	24.76	22.31	22.20	28.41	30.62	30.53	29.54	28.61	29.17	28.01
2019	39.40	38.47	33.60	30.01	26.85	25.62	32.32	34.72	35.09	34.66	32.41	33.22	33.03
2020	34.31	34.10	32.24	28.42	25.70	25.76	32.11	34.54	35.34	35.40	33.61	33.57	32.09
2021	35.35	35.54	32.74	29.15	26.38	26.56	32.91	35.62	36.67	35.93	35.49	36.19	33.21
2022	42.21	41.06	38.00	35.14	33.97	35.40	39.04	43.41	43.88	42.07	45.17	45.86	40.43
2023	47.21	46.73	43.48	39.99	38.89	39.88	44.42	48.95	49.01	49.22	50.09	49.29	45.60
2024	48.15	48.69	45.91	42.62	40.31	40.77	45.92	50.88	51.94	49.97	50.77	51.17	47.26
2025	54.61	55.30	52.15	49.45	46.44	47.12	53.28	58.08	59.10	57.17	57.82	58.04	54.05
2026	57.36	57.93	54.46	50.32	47.87	49.20	54.95	60.19	61.59	60.29	60.21	59.77	56.18
2027	59.48	59.81	56.41	52.70	49.86	50.88	56.81	62.40	63.51	61.13	62.12	61.55	58.05
2028	63.94	63.83	60.44	56.23	54.12	53.50	60.48	66.80	66.97	65.03	66.56	65.83	61.98
2029	73.47	74.28	68.98	64.28	61.94	62.81	69.98	76.82	78.14	77.31	79.69	78.99	72.22
2030	79.76	81.18	76.00	72.47	69.44	70.24	77.63	84.33	87.22	86.68	91.41	91.00	80.61
2031	80.57	81.63	77.58	74.54	71.33	71.95	79.51	86.15	88.89	88.03	91.94	91.89	82.00
2032	84.28	84.41	80.72	77.34	72.73	75.14	83.20	90.82	93.28	92.80	95.08	93.76	85.30
2033	88.46	89.07	86.13	81.95	77.58	79.03	87.62	96.01	98.70	97.65	108.68	107.28	91.51
2034	95.27	96.06	89.83	85.58	81.87	81.59	91.02	99.02	101.62	99.50	100.74	98.90	93.42
2035	94.59	95.71	91.75	85.02	80.51	80.16	90.33	98.86	102.30	99.60	97.27	95.93	92.67
2036	96.81	97.85	93.40	86.74	81.90	82.10	92.27	99.98	104.35	101.16	98.18	98.21	94.41
2037	99.42	99.76	95.10	89.17	84.86	83.86	93.76	101.85	106.15	103.09	100.85	100.53	96.53

Figure N-47: Forecast of Mid-C Power Prices for Base + Low Demand Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	30.29	30.13	28.60	24.42	20.92	20.60	27.37	29.84	29.88	28.19	27.14	28.08	27.12
2019	28.93	28.59	27.31	24.88	21.86	20.89	27.64	30.22	30.56	28.81	27.25	27.76	27.06
2020	28.60	28.33	27.30	24.49	20.79	20.96	27.81	30.55	31.30	30.50	28.53	29.01	27.35
2021	30.10	29.90	28.46	25.42	21.48	21.70	28.77	31.99	32.40	29.94	29.32	30.18	28.30
2022	36.13	35.67	32.68	29.99	28.97	30.05	34.81	38.11	37.90	35.37	36.32	36.53	34.38
2023	37.53	37.53	35.00	32.34	31.09	32.99	37.41	40.62	40.60	39.76	39.69	39.17	36.98
2024	39.20	39.99	37.46	35.22	32.93	34.44	39.56	43.32	44.39	41.66	41.13	41.26	39.21
2025	42.45	43.09	40.68	39.19	36.74	38.11	43.06	46.82	48.22	45.76	44.51	44.55	42.76
2026	45.73	46.30	44.05	41.35	39.32	41.16	46.02	50.06	51.29	49.93	48.46	47.81	45.96
2027	48.56	49.16	46.77	44.17	42.01	43.85	48.51	52.52	53.71	51.77	50.98	50.50	48.54
2028	51.96	52.22	49.73	47.80	45.47	46.92	51.43	55.84	56.49	55.16	55.42	54.32	51.90
2029	55.53	56.55	52.97	50.30	47.48	49.29	54.47	59.38	60.69	59.30	58.91	57.86	55.23
2030	58.86	59.54	55.03	52.36	49.85	50.47	56.56	60.96	63.13	61.82	60.98	60.68	57.52
2031	62.08	62.74	58.55	55.87	53.03	53.60	60.14	64.81	67.31	65.65	65.06	64.80	61.13
2032	66.01	66.52	62.55	59.15	55.29	57.72	64.16	69.64	72.15	71.17	71.54	69.89	65.48
2033	70.29	71.17	66.67	63.23	59.41	60.94	67.93	73.97	76.65	74.50	74.84	73.37	69.41
2034	74.17	74.84	68.69	65.89	62.19	62.69	70.43	76.66	78.87	76.94	77.85	76.05	72.11
2035	76.62	77.53	72.47	68.54	64.35	65.13	73.84	80.86	83.96	81.74	82.20	80.27	75.63
2036	79.91	80.81	75.42	70.92	66.17	67.31	77.33	84.00	87.68	83.99	84.18	83.51	78.44
2037	83.28	84.03	78.20	73.86	69.64	70.16	80.75	87.49	90.81	86.86	87.97	86.77	81.65

Figure N-48: Forecast of Mid-C Power Prices for Base + High Demand Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	32.80	32.76	30.05	25.25	23.29	23.32	29.25	31.23	30.95	29.95	29.24	30.50	29.05
2019	32.00	31.38	28.82	25.95	24.26	24.07	29.49	31.63	31.98	31.44	29.70	30.64	29.28
2020	32.19	31.53	28.68	25.74	23.53	24.37	29.98	32.21	32.96	33.19	31.52	31.88	29.81
2021	34.84	34.00	30.36	26.87	24.71	25.62	31.34	33.97	34.66	33.66	33.79	34.37	31.52
2022	39.79	38.52	35.42	31.93	30.75	32.17	36.97	41.27	41.72	39.39	39.88	40.13	37.33
2023	41.21	40.82	37.73	34.33	33.06	35.03	39.76	44.26	44.68	44.71	44.40	43.02	40.25
2024	43.08	44.18	40.53	38.02	35.37	36.93	43.12	48.20	49.52	46.63	45.22	46.15	43.08
2025	48.04	48.83	43.92	42.55	39.85	40.90	47.49	52.77	54.38	51.46	49.85	50.88	47.58
2026	52.75	53.35	48.02	44.95	42.82	44.62	51.21	57.30	58.74	56.62	55.36	54.79	51.71
2027	56.87	57.19	52.09	48.80	46.13	47.76	54.82	61.38	62.14	59.13	58.77	58.69	55.31
2028	58.96	58.65	54.39	52.00	49.65	50.55	57.77	64.13	63.45	61.68	62.09	61.63	57.91
2029	63.41	64.21	58.67	55.23	52.51	53.31	61.59	69.04	68.71	66.41	65.22	65.77	62.01
2030	66.72	67.10	61.21	57.98	55.01	55.16	63.78	71.05	71.73	68.93	68.18	69.67	64.71
2031	70.49	70.82	64.95	61.57	58.68	58.64	67.50	74.55	75.81	72.62	72.58	73.94	68.51
2032	75.15	74.69	69.39	65.23	61.90	63.55	72.41	79.88	80.43	77.73	79.33	79.33	73.25
2033	78.91	78.60	72.92	69.53	66.49	66.91	76.08	83.37	83.69	80.00	82.25	82.67	76.78
2034	82.17	81.54	74.19	71.18	68.51	68.56	77.49	85.11	84.86	82.37	84.88	84.97	78.82
2035	85.42	85.24	78.42	73.96	70.38	70.41	80.00	89.38	89.70	86.51	88.66	89.29	82.28
2036	87.63	87.23	80.56	76.20	72.06	72.68	82.77	90.91	92.43	88.42	90.37	91.96	84.44
2037	90.57	90.10	83.72	79.68	75.69	75.76	86.06	93.92	95.20	91.47	93.95	94.97	87.59

Figure N-49: Forecast of Mid-C Power Prices for Base + Low CAR CO_2 Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	31.22	30.82	28.92	24.26	21.71	21.39	26.66	29.39	28.89	27.11	27.50	28.73	27.22
2019	29.77	29.12	27.66	24.75	22.73	22.04	26.78	29.66	29.64	28.32	27.73	28.60	27.23
2020	29.58	29.33	27.71	24.86	22.36	22.70	27.49	30.39	30.78	30.00	29.58	29.82	27.88
2021	31.27	30.86	28.91	25.97	23.40	23.67	28.67	31.70	31.77	30.15	30.67	31.23	29.02
2022	37.43	36.59	33.74	30.77	29.64	31.11	35.49	39.42	39.73	37.57	37.57	37.64	35.56
2023	38.66	38.60	35.99	33.37	31.72	33.83	37.89	42.33	42.51	42.72	41.57	40.19	38.28
2024	40.33	41.16	38.86	37.03	34.10	35.57	40.89	45.79	47.21	44.40	42.74	42.71	40.90
2025	44.03	44.51	42.35	40.81	38.21	39.74	45.00	50.01	51.86	49.00	46.64	46.64	44.90
2026	47.39	48.00	45.79	43.07	40.81	43.02	48.22	53.39	55.45	53.88	51.00	50.02	48.34
2027	50.92	51.41	49.09	46.83	43.88	46.11	51.23	56.87	58.73	56.25	54.01	53.26	51.55
2028	54.64	54.92	52.06	50.03	47.69	49.23	54.65	61.03	62.00	60.20	58.41	57.42	55.19
2029	58.72	59.45	55.82	53.15	50.27	51.69	57.86	64.91	66.79	64.96	61.92	60.99	58.88
2030	62.28	62.85	58.53	55.72	52.83	53.74	60.33	67.09	69.90	66.74	64.64	64.69	61.61
2031	65.64	66.07	61.96	59.11	56.47	57.07	64.15	70.81	73.74	70.71	68.77	68.78	65.27
2032	69.60	69.91	66.25	62.66	59.08	61.20	68.22	75.68	78.44	76.29	75.48	74.09	69.74
2033	74.18	74.52	70.13	66.41	63.29	64.04	71.59	79.74	82.14	78.90	78.52	77.86	73.44
2034	78.29	78.48	71.87	68.56	65.46	66.20	74.04	82.25	83.90	81.15	81.31	80.25	75.98
2035	80.10	80.70	75.21	71.36	67.11	68.21	76.87	85.97	88.17	85.56	85.27	83.90	79.04
2036	83.28	83.78	77.88	74.41	69.13	70.59	80.32	88.63	91.63	87.69	87.08	87.18	81.80
2037	86.45	87.07	80.89	77.25	72.84	73.28	83.65	91.60	94.77	90.68	90.74	90.46	84.97

Figure N-50: Forecast of Mid-C Power Prices for Base + High CAR CO_2 Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
							MONTHS						
2018	31.29	31.01	28.97	24.43	21.84	21.83	28.03	30.57	30.32	28.98	27.61	28.72	27.80
2019	29.82	29.31	27.55	24.82	22.82	22.45	28.45	31.06	31.47	30.16	27.82	28.69	27.87
2020	29.65	29.31	27.70	24.85	22.40	23.09	29.24	31.80	32.76	32.40	29.77	29.74	28.56
2021	31.39	31.40	28.97	26.00	23.53	23.98	30.26	33.32	34.41	32.42	31.00	31.31	29.83
2022	37.39	36.41	33.51	30.59	29.57	31.08	35.39	39.00	39.37	37.17	37.34	37.47	35.36
2023	38.47	38.54	35.95	33.33	31.47	33.74	37.67	41.88	42.11	42.16	41.19	40.11	38.05
2024	40.30	41.06	38.89	36.73	33.86	35.34	40.60	45.16	46.59	44.04	42.29	42.50	40.61
2025	43.66	44.22	42.32	40.52	37.90	39.56	44.49	49.25	51.05	48.24	46.10	46.30	44.47
2026	47.20	47.79	45.51	42.78	40.62	42.85	47.63	52.55	54.63	53.04	50.47	49.55	47.89
2027	50.54	50.83	48.78	46.30	43.52	45.73	50.51	55.84	57.59	55.08	53.30	52.74	50.90
2028	53.97	54.26	51.65	49.65	47.21	48.97	53.70	59.87	60.47	58.86	57.93	56.96	54.46
2029	58.22	58.83	55.45	52.83	49.86	51.45	57.29	64.00	65.65	63.60	61.47	60.61	58.27
2030	61.97	62.40	58.19	55.71	52.64	53.61	59.90	66.53	69.03	65.97	64.34	64.34	61.22
2031	65.01	65.49	61.63	59.00	55.99	56.92	63.54	70.25	73.09	69.82	68.53	68.45	64.81
2032	69.24	69.31	65.84	62.32	58.97	61.06	67.94	75.25	77.63	75.31	75.02	73.86	69.31
2033	73.66	73.90	69.79	66.05	62.77	64.12	71.21	79.18	81.20	78.00	78.10	77.36	72.94
2034	77.84	78.10	71.48	68.18	65.02	65.65	73.48	81.79	82.69	80.10	80.75	79.84	75.41
2035	79.88	80.58	75.04	71.12	66.71	67.62	76.14	85.17	87.32	84.88	84.96	83.68	78.59
2036	82.22	82.79	77.05	73.47	68.16	69.25	78.75	86.47	89.74	86.04	86.26	86.37	80.55
2037	85.57	85.66	80.12	76.28	71.66	71.96	81.82	89.54	92.70	88.77	89.51	89.46	83.59

Figure N-51: Forecast of Mid-C Power Prices for Base + CPP only Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
							MONTHS						
2018	30.00	29.55	28.20	23.04	19.54	19.10	25.48	28.99	28.58	26.40	26.66	27.96	26.12
2019	28.81	28.13	26.90	23.86	20.37	19.55	25.71	29.32	29.17	26.78	26.86	27.91	26.11
2020	28.86	28.23	26.80	23.43	20.01	19.99	26.30	29.93	30.19	28.65	28.24	29.08	26.64
2021	30.26	29.62	28.00	24.24	20.82	20.86	27.26	31.27	31.10	28.53	29.14	30.36	27.62
2022	36.82	36.32	33.05	30.23	29.18	30.37	34.57	38.06	38.09	36.35	36.81	37.12	34.75
2023	38.15	38.28	35.58	32.78	31.04	33.10	36.96	40.91	40.83	40.61	40.13	39.63	37.33
2024	39.92	40.63	38.46	36.54	33.47	34.92	39.83	43.87	45.27	42.34	41.93	41.96	39.93
2025	43.12	43.71	41.96	40.18	37.56	38.83	43.71	48.14	49.13	46.13	45.33	45.63	43.62
2026	46.75	47.14	45.19	42.53	40.26	42.17	46.73	51.35	52.44	50.87	49.36	48.93	46.98
2027	49.82	50.27	48.49	46.16	43.33	45.10	49.67	54.64	55.50	53.06	52.49	52.15	50.06
2028	53.36	53.65	51.44	49.52	47.04	48.26	52.89	58.50	58.59	56.88	57.02	56.38	53.63
2029	57.32	58.01	55.00	52.55	49.48	51.12	56.28	62.36	63.18	61.06	60.72	60.19	57.27
2030	60.95	61.36	57.59	55.24	52.10	52.88	58.39	64.35	66.20	63.56	63.31	63.54	59.96
2031	63.97	64.57	61.07	58.66	55.50	56.16	62.12	67.91	70.00	67.38	67.45	67.52	63.52
2032	68.25	68.21	65.33	61.63	58.29	60.67	66.66	72.93	75.08	73.22	73.92	72.96	68.10
2033	72.38	72.71	69.27	65.47	62.44	63.47	69.97	76.68	78.53	75.99	76.91	76.65	71.71
2034	76.34	76.39	70.62	67.82	64.39	64.85	71.95	78.54	80.25	78.07	79.54	78.76	73.96
2035	78.23	78.62	73.92	70.57	65.77	66.41	74.31	81.74	83.79	81.80	83.47	82.31	76.75
2036	80.76	81.13	76.44	72.87	67.46	68.38	77.02	83.46	86.42	83.42	84.92	85.23	78.96
2037	83.81	83.66	79.23	75.51	70.41	70.61	79.70	85.88	89.02	85.72	88.04	88.12	81.64

Figure N-52: Forecast of Mid-C Power Prices for Base + All-thermal CO_2 Scenario (Nominal $/MWh)

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
						MONTHS							
2018	34.78	34.55	32.77	26.83	25.55	26.69	30.88	34.15	33.42	31.94	31.73	33.15	31.37
2019	34.16	33.61	31.76	28.06	26.31	27.14	31.42	34.98	35.28	33.64	32.78	33.83	31.91
2020	35.16	34.29	31.88	27.64	26.09	28.13	32.69	36.13	37.23	36.65	35.06	35.26	33.02
2021	36.55	35.96	33.12	28.76	27.30	29.13	33.67	37.73	38.79	36.58	36.29	36.60	34.21
2022	38.38	38.03	35.41	32.69	30.45	32.08	36.31	41.14	42.12	40.14	39.04	38.80	37.05
2023	39.90	40.05	37.88	35.03	32.66	34.65	39.00	43.98	45.11	45.39	43.39	41.53	39.88
2024	42.00	42.97	40.58	38.59	35.32	36.58	42.22	47.66	49.84	47.13	44.07	43.98	42.58
2025	45.59	46.82	43.85	42.93	39.48	40.87	46.59	52.34	54.75	51.78	48.33	48.26	46.80
2026	49.10	50.15	46.96	44.56	42.01	44.18	49.60	55.48	58.25	56.57	52.80	51.22	50.07
2027	52.56	53.49	50.60	48.02	45.20	47.21	52.66	59.25	61.69	58.61	55.57	54.42	53.27
2028	56.25	57.00	53.72	51.51	48.97	50.35	56.23	63.47	65.08	62.74	60.29	58.75	57.03
2029	60.52	61.73	57.69	54.51	51.60	53.07	59.77	67.56	70.29	67.80	64.02	62.44	60.92
2030	64.18	65.38	60.47	57.37	54.26	55.40	62.46	69.94	73.90	70.10	66.50	66.15	63.84
2031	67.70	68.75	64.21	60.99	57.91	58.77	66.68	74.13	78.12	74.29	71.07	70.54	67.76
2032	71.12	71.63	67.46	63.67	60.32	62.52	70.18	78.07	81.90	78.73	77.15	75.36	71.51
2033	75.61	76.66	71.63	67.74	64.12	65.89	73.93	82.56	85.95	81.51	80.59	79.21	75.45
2034	79.73	80.20	73.28	70.00	67.04	68.11	76.37	85.26	88.07	84.61	83.68	82.01	78.20
2035	81.68	83.15	77.00	72.18	68.50	69.86	78.91	88.70	92.21	89.20	87.56	85.32	81.19
2036	84.26	85.21	78.69	74.65	70.21	71.87	81.28	90.32	94.63	90.20	88.67	88.44	83.20
2037	87.33	88.06	81.53	77.62	73.25	74.27	83.89	92.94	96.97	92.41	91.97	91.55	85.98

5. OUTPUTS: SCENARIO ANALYSIS RESULTS

Expected Portfolio Costs – Scenarios

This table summarizes the expected costs of the different portfolios.

Figure N-53: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenarios

Expected Cost for Portfolios

Scenario	NPV to 2018 ($Millions)					
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Incremental Rev. Req.	End Effects	REC Revenue
Resource Plan	11,994	4,687	618	6,351	354	(16)
Base	11,981	4,664	569	6,396	364	(11)
Low	8,611	1,970	423	5,692	531	(4)
High	15,398	5,240	700	9,041	520	(103)
High + Low Demand	11,769	5,006	572	5,959	280	(48)
Base + Low Gas Price	10,772	4,187	423	5,767	399	(5)
Base + High Gas Price	13,269	5,131	621	7,290	348	(122)
Base + Low Demand	10,701	4,393	569	5,425	325	(10)
Base + High Demand	13,755	3,979	621	8,806	382	(33)
Base No CO2	10,446	670	618	8,982	181	(5)
Base + Low CO2 w CPP	11,932	4,112	569	6,971	303	(23)
Base + High CO2	11,976	4,408	569	6,686	337	(23)
Base + CAR only	10,732	5,590	621	4,089	441	(9)
Base + CPP Only	11,875	4,176	569	6,741	401	(11)
Base + All-thermal CO2	12,664	3,976	621	7,700	390	(23)

Figure N-54: Annual Revenue Requirements for Optimal Portfolio ($Millions)

	Resource Plan	Base	Low	High	High + Low Demand	Base + Low Gas Price	Base + High Gas Price	Base + Low Demand
2018	730	728	647	787	696	683	732	693
2019	777	773	670	903	767	715	823	729
2020	876	869	765	988	846	812	905	822
2021	890	883	774	1,006	852	824	918	830
2022	973	962	707	1,187	920	885	1,004	867
2023	941	957	664	1,203	926	881	1,039	860
2024	962	968	690	1,218	948	881	1,082	863
2025	1,007	989	692	1,272	980	922	1,124	877
2026	1,038	1,045	673	1,351	1,011	954	1,181	900
2027	1,095	1,079	666	1,369	1,012	961	1,186	922
2028	1,151	1,134	683	1,417	1,051	998	1,226	968
2029	1,240	1,222	731	1,665	1,207	1,065	1,409	1,042
2030	1,298	1,303	789	1,849	1,352	1,146	1,588	1,113
2031	1,459	1,439	921	2,029	1,521	1,288	1,705	1,267
2032	1,688	1,683	1,056	2,310	1,749	1,498	1,956	1,475
2033	1,744	1,779	1,101	2,514	1,843	1,564	2,124	1,562
2034	1,835	1,842	1,098	2,582	1,883	1,573	2,176	1,618
2035	1,927	1,943	1,122	2,607	1,955	1,603	2,202	1,732
2036	1,981	1,995	1,191	2,720	2,015	1,593	2,293	1,748
2037	2,023	2,042	1,175	2,812	2,053	1,594	2,331	1,786
20-yr NPV	11,640	11,617	8,081	14,879	11,489	10,373	12,921	10,376
End Effects	354	364	531	520	280	399	348	325
Expected Cost	**11,994**	**11,981**	**8,611**	**15,398**	**11,769**	**10,772**	**13,269**	**10,701**

Figure N-55: Annual Revenue Requirements for Optimal Portfolio ($Millions) Cont.

	Base + High Demand	Base No CO2	Base + Low CO2 w CPP	Base + High CO2	Base + CAR only	Base + CPP Only	Base + All Thermal CO2
2018	775	698	721	729	689	696	818
2019	834	743	765	774	735	738	869
2020	938	839	862	870	831	832	968
2021	985	850	874	884	844	842	988
2022	1,108	824	965	965	841	962	958
2023	1,070	833	959	959	837	956	959
2024	1,120	837	983	982	840	968	996
2025	1,169	871	1,001	999	882	988	1,041
2026	1,241	926	1,055	1,053	901	1,044	1,077
2027	1,282	947	1,089	1,086	925	1,078	1,120
2028	1,344	987	1,144	1,140	961	1,134	1,175
2029	1,450	1,056	1,230	1,226	1,051	1,220	1,293
2030	1,505	1,091	1,309	1,306	1,118	1,300	1,354
2031	1,708	1,238	1,443	1,439	1,236	1,434	1,539
2032	1,994	1,479	1,683	1,680	1,437	1,678	1,760
2033	2,072	1,491	1,771	1,768	1,507	1,775	1,824
2034	2,159	1,516	1,837	1,833	1,559	1,835	1,917
2035	2,278	1,584	1,940	1,939	1,639	1,934	2,015
2036	2,355	1,723	1,996	1,987	1,801	1,984	2,101
2037	2,455	1,732	2,042	2,034	1,821	2,029	2,145
20-yr NPV	13,373	10,265	11,628	11,639	10,292	11,474	12,273
End Effects	382	181	303	337	441	401	390
Expected Cost	**13,755**	**10,446**	**11,932**	**11,976**	**10,732**	**11,875**	**12,664**

Incremental Portfolio Builds by Year – Scenarios

Figure N-56: Incremental Portfolio Builds by Year (nameplate MW)

Resource Plan Forecast

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	266	-	-	-	45	9
2023	-	-	-	-	-	-	-	50	-	41	3
2024	-	-	-	-	-	112	25	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	-	239	-	-	-	-	-	-	36	12
2027	-	-	239	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	-	478	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	25	-	-	-	20	1
2033	-	-	-	-	-	59	-	-	-	19	1
2034	-	-	239	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	-	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,912**	**-**	**-**	**486**	**25**	**50**	**-**	**714**	**148**
Winter	**188**	**-**	**1,912**	**-**	**-**	**-**	**15**	**38**	**-**	**714**	**114**

Figure N-57: Incremental Portfolio Builds by Year (nameplate MW)

Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	108	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	478	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0.0
2030	-	-	239	-	-	-	-	-	-	20	0.5
2031	-	-	239	-	-	-	-	-	-	20	0.5
2032	-	-	-	-	-	25	-	25	-	20	0.5
2033	-	-	239	-	-	63	-	-	-	19	0.3
2034	-	-	-	-	-	-	-	-	-	17	0.4
2035	-	-	-	-	-	-	-	25	-	16	0.4
2036	-	-	478	-	-	-	-	-	-	16	0.7
2037	-	-	63	-	-	25	-	-	-	16	0.2
Total	**188**	**-**	**1,975**	**-**	**-**	**486**	**-**	**50**	**-**	**714**	**58**
Winter	**188**	**-**	**1,975**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**45**

Figure N-58: Incremental Portfolio Builds by Year (nameplate MW)

Base + No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	50	-	41	3
2024	-	-	-	-	-	29	50	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	413	-	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0.0
2030	-	-	-	-	-	-	-	-	-	20	1.4
2031	-	413	-	-	-	32	-	-	-	20	1.2
2032	-	413	-	-	-	-	-	-	-	20	1.4
2033	-	-	-	-	-	72	-	-	-	19	0.6
2034	-	-	-	-	-	-	-	-	-	17	0.9
2035	-	-	-	-	-	-	-	-	-	16	1.1
2036	-	413	-	-	-	-	-	-	-	16	1.8
2037	-	-	18	-	-	26	-	-	-	16	0.6
Total	**188**	**1,652**	**257**	**-**	**-**	**484**	**50**	**50**	**-**	**714**	**148**
Winter	**188**	**-**	**-**	**-**	**-**	**-**	**30**	**38**	**-**	**714**	**114**

Figure N-59: Incremental Portfolio Builds by Year (nameplate MW)
Low Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	26	2
2019	-	-	-	-	-	-	-	-	-	51	4
2020	-	-	-	-	-	-	-	-	-	98	4
2021	-	-	-	-	-	-	-	-	-	95	3
2022	-	-	-	-	-	-	-	-	-	41	1
2023	-	-	-	-	-	47	-	-	-	36	5
2024	-	-	-	-	-	172	-	-	-	34	9
2025	-	-	-	-	-	-	-	-	-	33	14
2026	-	-	239	-	-	-	-	25	-	32	14
2027	-	-	-	-	-	-	-	-	-	31	5
2028	-	-	-	-	-	50	-	-	-	26	0
2029	-	-	-	-	-	-	-	25	-	19	0.1
2030	-	-	239	-	-	-	-	-	-	18	0.7
2031	-	-	478	-	-	26	-	-	-	19	0.6
2032	-	-	-	-	-	-	-	-	-	19	0.7
2033	-	-	239	-	-	49	-	-	-	18	0.4
2034	-	-	-	-	-	-	-	-	-	16	0.5
2035	-	-	-	-	-	-	-	-	-	15	0.6
2036	-	413	-	-	-	-	-	-	-	15	0.8
2037	-	-	60	-	-	25	-	-	-	15	0.4
Total	**188**	**413**	**1,255**	**-**	**-**	**369**	**-**	**50**	**-**	**658**	**67**
Winter	**188**	**413**	**1,255**	**-**	**-**	**-**	**-**	**38**	**-**	**658**	**52**

Figure N-60: Incremental Portfolio Builds by Year (nameplate MW)
High Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	30	11
2019	-	-	-	-	-	-	-	-	-	58	21
2020	-	-	-	-	-	-	-	-	-	105	30
2021	-	-	-	-	-	-	-	-	-	101	29
2022	-	-	478	-	-	261	-	-	-	46	9
2023	-	-	-	-	300	-	-	-	-	42	3
2024	-	-	-	-	-	214	-	-	-	40	8
2025	-	-	-	-	-	-	-	-	-	38	11
2026	-	-	478	-	-	-	-	-	-	37	12
2027	-	-	-	-	-	-	-	25	-	37	5
2028	-	-	-	-	-	-	-	-	-	29	0
2029	-	-	239	-	-	-	-	-	-	21	0
2030	-	-	-	-	-	-	-	-	-	20	1.4
2031	-	-	717	-	-	-	-	-	-	20	1.2
2032	-	-	-	-	-	-	-	-	-	20	1.4
2033	-	-	239	-	-	-	-	-	-	19	0.6
2034	-	-	239	-	-	-	-	-	-	17	0.9
2035	-	-	-	-	-	-	-	-	-	16	1.1
2036	-	-	478	-	-	-	-	-	-	16	1.8
2037	-	-	7	-	-	25	-	25	-	16	0.6
Total	**188**	**-**	**2,875**	**-**	**300**	**500**	**-**	**50**	**-**	**728**	**148**
Winter	**188**	**-**	**2,875**	**-**	**136**	**-**	**-**	**38**	**-**	**728**	**114**

Figure N-61: Incremental Portfolio Builds by Year (nameplate MW)
High + Low Demand Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	-	-	-	-	-	-	-	45	1
2023	-	-	-	-	-	190	-	-	-	41	5
2024	-	-	-	-	-	285	-	-	-	38	9
2025	-	-	-	-	-	-	-	-	-	37	14
2026	-	-	239	-	-	-	-	-	-	36	14
2027	-	-	-	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0.1
2030	-	-	-	-	-	-	-	66	-	20	0.7
2031	-	-	717	-	-	-	-	-	-	20	0.6
2032	-	-	-	-	-	-	-	-	-	20	0.7
2033	-	-	-	-	-	-	-	-	-	19	0.4
2034	-	-	-	-	-	-	-	25	-	17	0.5
2035	-	-	239	-	-	-	-	-	-	16	0.6
2036	-	-	239	-	-	-	-	-	-	16	0.8
2037	-	-	141	-	-	25	-	-	-	16	0.4
Total	**188**	**-**	**1,575**	**-**	**-**	**500**	**-**	**91**	**-**	**714**	**67**
Winter	**188**	**-**	**1,575**	**-**	**-**	**-**	**-**	**69**	**-**	**714**	**52**

Figure N-62: Incremental Portfolio Builds by Year (nameplate MW)

Base + Low Gas Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	26	2
2019	-	-	-	-	-	-	-	-	-	51	4
2020	-	-	-	-	-	-	-	-	-	98	4
2021	-	-	-	-	-	-	-	-	-	95	3
2022	-	-	239	-	-	50	-	-	-	41	1
2023	-	-	-	-	-	222	-	-	-	36	5
2024	-	-	-	-	-	35	-	-	-	34	9
2025	-	-	-	-	-	-	-	29	-	33	14
2026	-	-	478	-	-	-	-	-	-	32	14
2027	-	-	-	-	-	-	-	-	-	31	5
2028	-	-	-	-	-	46	-	-	-	26	0
2029	-	-	-	-	-	25	-	-	-	19	0.1
2030	-	-	239	-	-	-	-	-	-	18	0.7
2031	-	-	239	-	-	26	-	-	-	19	0.6
2032	-	-	-	-	-	-	-	54	-	19	0.7
2033	-	-	239	-	-	74	-	-	-	18	0.4
2034	-	-	-	-	-	-	-	-	-	16	0.5
2035	-	-	-	-	-	-	-	25	-	15	0.6
2036	-	-	478	-	-	-	-	-	-	15	0.8
2037	-	-	70	-	-	27	-	-	-	15	0.4
Total	**188**	**-**	**1,982**	**-**	**-**	**504**	**-**	**108**	**-**	**658**	**67**
Winter	**188**	**-**	**1,982**	**-**	**-**	**-**	**-**	**82**	**-**	**658**	**52**

Figure N-63: Incremental Portfolio Builds by Year (nameplate MW)

Base + High Gas Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	300	-	-	-	-	41	4
2024	-	-	-	-	-	435	-	-	-	38	10
2025	-	-	-	-	-	-	-	26	-	37	13
2026	-	-	478	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0.1
2030	-	-	239	-	-	-	-	-	-	20	1.5
2031	-	-	239	-	-	-	-	-	-	20	1.4
2032	-	-	-	-	-	-	-	25	-	20	1.5
2033	-	-	239	-	-	-	-	-	-	19	0.7
2034	-	-	-	-	-	-	-	-	-	17	1.1
2035	-	-	-	-	-	-	-	25	-	16	1.2
2036	-	-	478	-	-	-	-	-	-	16	1.9
2037	-	-	62	-	-	25	-	-	-	16	0.7
Total	**188**	**-**	**1,735**	**-**	**300**	**500**	**-**	**76**	**-**	**714**	**157**
Winter	**188**	**-**	**1,735**	**-**	**136**	**-**	**-**	**58**	**-**	**714**	**121**

Figure N-64: Incremental Portfolio Builds by Year (nameplate MW)

Base + Low Demand Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	-	-	-	-	-	-	-	45	1
2023	-	-	-	-	-	190	-	-	-	41	4
2024	-	-	-	-	-	64	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	239	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	239	-	-	-	-	-	-	20	0.5
2031	-	-	478	-	-	25	-	-	-	20	0.5
2032	-	-	-	-	-	-	-	-	-	20	0.5
2033	-	-	-	-	-	47	-	63	-	19	0.3
2034	-	-	-	-	-	-	-	39	-	17	0.4
2035	-	-	239	-	-	-	-	-	-	16	0.4
2036	-	-	239	-	-	-	-	-	-	16	0.7
2037	-	-	141	-	-	25	-	-	-	16	0.2
Total	**188**	**-**	**1,575**	**-**	**-**	**351**	**-**	**102**	**-**	**714**	**58**
Winter	**188**	**-**	**1,575**	**-**	**-**	**-**	**-**	**78**	**-**	**714**	**45**

Figure N-65: Incremental Portfolio Builds by Year (nameplate MW)

Base + High Demand Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	DR
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	239	-	-	-	-	-	-	99	29
2022	-	-	239	-	-	-	-	-	-	45	9
2023	-	-	-	-	-	190	-	-	-	41	4
2024	-	-	-	-	-	64	-	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	478	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	(0.1)
2029	-	-	-	-	-	-	-	-	-	20	0.1
2030	-	-	-	-	-	-	-	-	-	20	1.5
2031	-	-	717	-	-	25	-	25	-	20	1.4
2032	-	-	239	-	-	-	-	-	-	20	1.5
2033	-	-	-	-	-	47	-	-	-	19	0.7
2034	-	-	239	-	-	-	-	-	-	17	1.1
2035	-	-	-	-	-	-	-	-	-	16	1.2
2036	-	-	478	-	-	-	-	25	-	16	1.9
2037	-	-	135	-	-	25	-	-	-	16	0.7
Total	**188**	**-**	**3,003**	**-**	**-**	**351**	**-**	**75**	**-**	**714**	**157**
Winter	**188**	**-**	**3,003**	**-**	**-**	**-**	**-**	**57**	**-**	**714**	**121**

Figure N-66: Incremental Portfolio Builds by Year (nameplate MW)
Base + Low CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	200	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	478	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0.0
2030	-	-	239	-	-	-	-	-	-	20	0.5
2031	-	-	239	-	-	-	-	-	-	20	0.5
2032	-	-	-	-	-	-	-	25	-	20	0.5
2033	-	-	239	-	-	-	-	-	-	19	0.3
2034	-	-	-	-	-	-	-	-	-	17	0.4
2035	-	-	-	-	-	-	-	25	-	16	0.4
2036	-	-	478	-	-	-	-	-	-	16	0.7
2037	-	-	63	-	-	25	-	-	-	16	0.2
Total	**188**	**-**	**1,975**	**-**	**-**	**490**	**-**	**50**	**-**	**714**	**58**
Winter	**188**	**-**	**1,975**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**45**

Figure N-67: Incremental Portfolio Builds by Year (nameplate MW)
Base + High CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	200	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	478	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	-	-	20	0.0
2030	-	-	239	-	-	-	-	-	-	20	0.5
2031	-	-	239	-	-	-	-	-	-	20	0.5
2032	-	-	-	-	-	-	-	25	-	20	0.5
2033	-	-	239	-	-	-	-	-	-	19	0.3
2034	-	-	-	-	-	-	-	-	-	17	0.4
2035	-	-	-	-	-	-	-	25	-	16	0.4
2036	-	-	478	-	-	-	-	-	-	16	0.7
2037	-	-	63	-	-	25	-	-	-	16	0.2
Total	**188**	**-**	**1,975**	**-**	**-**	**490**	**-**	**50**	**-**	**714**	**58**
Winter	**188**	**-**	**1,975**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**45**

Figure N-68: Incremental Portfolio Builds by Year (nameplate MW)
Base + Mid CAR only Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	114	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	90	-	-	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	-	-	-	-	-	50	-	20	0.1
2030	-	-	239	-	-	-	-	-	-	20	1.5
2031	-	-	239	-	-	32	-	-	-	20	1.4
2032	-	-	-	-	-	-	-	-	41	20	1.5
2033	-	-	239	-	-	73	-	-	-	19	0.7
2034	-	-	-	-	-	-	-	-	-	17	1.1
2035	-	-	-	-	-	-	-	-	-	16	1.2
2036	-	-	478	-	-	-	-	-	-	16	1.9
2037	-	-	73	-	-	25	-	-	-	16	0.7
Total	**188**	**-**	**1,859**	**-**	**-**	**486**	**-**	**50**	**41**	**714**	**157**
Winter	**188**	**-**	**1,859**	**-**	**-**	**-**	**-**	**38**	**41**	**714**	**121**

Figure N-69: Incremental Portfolio Builds by Year (nameplate MW)
Base + CPP Only Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	108	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	478	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	0.0
2029	-	-	-	-	-	-	-	-	-	20	0.0
2030	-	-	239	-	-	-	-	-	-	20	0.5
2031	-	-	239	-	-	-	-	-	-	20	0.5
2032	-	-	-	-	-	25	-	25	-	20	0.5
2033	-	-	239	-	-	63	-	-	-	19	0.3
2034	-	-	-	-	-	-	-	-	-	17	0.4
2035	-	-	-	-	-	-	-	25	-	16	0.4
2036	-	-	478	-	-	-	-	-	-	16	0.7
2037	-	-	63	-	-	25	-	-	-	16	0.2
Total	**188**	**-**	**1,975**	**-**	**-**	**486**	**-**	**50**	**-**	**714**	**58**
Winter	**188**	**-**	**1,975**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**45**

Figure N-70: Incremental Portfolio Builds by Year (nameplate MW)
Scenario: Base + All Thermal CO_2

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	108	-	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	0
2029	-	-	239	-	-	-	-	-	-	20	0.1
2030	-	-	-	-	-	-	-	-	-	20	1.5
2031	-	413	-	-	-	-	-	-	-	20	1.4
2032	-	-	-	-	-	25	-	-	-	20	1.5
2033	-	-	-	-	-	63	-	-	25	19	0.7
2034	-	-	239	-	-	-	-	-	-	17	1.1
2035	-	-	-	-	-	-	-	-	-	16	1.2
2036	-	413	-	-	-	-	-	-	-	16	1.9
2037	-	-	70	-	-	25	-	-	-	16	0.7
Total	**188**	**826**	**1,026**	**-**	**-**	**486**	**-**	**75**	**25**	**714**	**157**
Winter	**188**	**826**	**1,026**	**-**	**-**	**-**	**-**	**57**	**25**	**714**	**121**

Portfolio CO_2 Emissions – Scenarios

Figure N-71: Total Portfolio CO_2 Emissions
Emission PSE Portfolio - All (Millions Tons)

	Resource Plan	Base	Low	High	High + Low Demand	Base + Low Gas Price	Base + High Gas Price	Base + Low Demand
2018	12.30	12.30	10.58	13.10	11.94	11.18	12.31	11.92
2019	12.02	12.02	10.16	13.90	12.61	10.80	13.13	11.45
2020	11.64	11.64	9.57	13.27	11.84	10.34	12.40	10.90
2021	11.17	11.17	9.66	12.34	10.91	10.37	11.52	10.47
2022	5.87	6.06	8.53	8.61	6.82	5.25	7.41	5.08
2023	6.09	6.12	8.17	9.09	7.27	5.18	7.88	5.48
2024	6.23	6.27	7.89	8.67	6.81	5.24	7.32	5.36
2025	6.85	6.86	8.25	9.44	7.54	5.53	8.01	5.92
2026	7.28	7.33	8.27	9.40	7.67	5.75	8.20	6.35
2027	7.55	7.57	8.05	9.30	7.44	5.69	8.13	6.38
2028	7.73	7.73	8.41	9.94	7.84	5.84	8.66	6.56
2029	8.14	8.14	8.34	9.98	7.89	6.09	8.63	6.86
2030	8.24	8.30	8.39	9.67	7.88	6.23	8.59	6.71
2031	8.65	8.66	8.82	10.04	8.21	6.62	8.87	7.14
2032	9.42	9.42	9.27	10.44	8.60	7.37	9.25	7.87
2033	9.58	9.63	9.57	10.79	8.90	7.23	9.59	8.07
2034	9.52	9.53	9.52	10.73	8.72	7.52	9.49	7.93
2035	9.49	9.49	9.88	11.01	8.97	7.96	9.66	8.15
2036	7.64	7.64	7.31	8.27	6.19	8.27	6.77	6.39
2037	7.81	7.83	7.45	8.51	6.26	8.47	6.76	6.58

Figure N-72: Total Portfolio CO_2 Emissions

Emission PSE Portfolio - All (Millions Tons)

	Base + High Demand	Base No CO2	Base + Low CO2 w CPP	Base + High CO2	Base + CAR only	Base + CPP Only	Base + All Thermal CO2
2018	13.05	12.66	12.31	12.33	12.24	12.68	7.62
2019	12.96	12.31	12.02	12.06	11.95	12.36	7.43
2020	12.59	11.83	11.63	11.65	11.53	11.91	6.82
2021	12.09	11.69	11.18	11.20	11.08	11.76	6.76
2022	7.92	10.28	6.65	6.46	9.66	6.04	6.84
2023	7.96	9.82	6.61	6.42	9.31	6.05	6.82
2024	7.97	9.85	6.54	6.42	9.40	6.16	6.97
2025	8.64	10.17	7.16	7.02	9.59	6.85	7.53
2026	9.18	9.38	7.64	7.49	8.44	7.34	7.59
2027	9.42	9.22	7.86	7.61	8.30	7.54	7.78
2028	9.71	9.55	8.12	7.91	8.70	7.77	8.00
2029	9.86	9.53	8.35	8.22	8.75	8.04	8.18
2030	9.94	9.73	8.46	8.38	8.94	8.20	8.28
2031	10.64	10.37	8.85	8.73	9.45	8.57	8.96
2032	11.52	11.00	9.60	9.48	10.05	9.32	9.39
2033	11.88	11.28	9.87	9.72	10.34	9.48	9.56
2034	11.75	11.21	9.87	9.71	10.21	9.28	9.45
2035	11.78	11.37	9.85	9.73	10.39	9.28	9.39
2036	9.63	8.71	7.94	7.67	7.64	7.37	7.22
2037	10.08	8.79	8.21	7.86	7.72	7.52	7.22

6. OUTPUTS: SENSITIVITY ANALYSIS RESULTS

Expected Portfolio Costs – Sensitivities

This table summarizes the expected costs of the different sensitivity analysis.

Figure N-73: Annual Revenue Requirements for Sensitivities ($Millions)

Sensitivity	NPV to 2018 ($Millions)					
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Incremental Rev. Req.	Generic End Effects	REC Revenue
Retire Colstrip 2018 Base	11,944	4,853	572	6,163	370	(13)
Retire Colstrip 2018 No CO2	10,456	839	618	8,821	181	(5)
Retire Colstrip 2025 Base	11,766	5,091	572	5,772	344	(13)
Retire Colstrip 2025 No CO2	10,647	656	621	9,252	123	(5)
Retire Colstrip 2030 Base	11,833	4,893	572	6,025	356	(13)
Retire Colstrip 2030 No CO2	10,462	695	621	9,006	144	(5)

Figure N-74: Annual Revenue Requirements for Sensitivities ($Millions)

Sensitivity	NPV to 2018 ($Millions)					
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Incremental Rev. Req.	Generic End Effects	REC Revenue
Retire Encogen Base	11,975	4,695	621	6,365	304	(11)
Retire Ferndale Base	12,013	4,611	572	6,505	337	(11)
Retire Goldendale Base	11,971	4,652	621	6,390	318	(11)
Retire Mint Farm Base	11,974	4,652	621	6,394	318	(11)
Retire Sumas Base	11,977	4,695	621	6,355	317	(11)
Retire Encogen No CO2	10,721	2,211	621	7,374	519	(5)
Retire Ferndale No CO2	10,787	2,207	621	7,402	562	(5)
Retire Goldendale No CO2	10,782	2,195	621	7,404	566	(5)
Retire Mint Farm No CO2	10,805	2,195	621	7,406	588	(5)
Retire Sumas No CO2	10,795	2,207	621	7,406	565	(5)
Retire Encogen All Thermal CO2	12,668	3,584	621	8,143	343	(23)
Retire Ferndale All Thermal CO2	12,702	3,508	621	8,242	353	(23)
Retire Goldendale All Thermal CO2	12,663	3,508	621	8,235	322	(23)
Retire Mint Farm All Thermal CO2	12,664	3,508	621	8,229	329	(23)
Retire Sumas All Thermal CO2	12,665	3,584	621	8,129	355	(23)

Figure N-75: Annual Revenue Requirements for Sensitivities ($Millions)

Sensitivity	NPV to 2018 ($Millions)					
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Incremental Rev. Req.	Generic End Effects	REC Revenue
No New Thermal	13,343	4,881	748	6,709	1,045	(39)
High Thermal Cost	12,194	4,736	621	6,409	440	(11)
Energy Storage Battery	11,988	4,699	618	6,325	357	(12)
Energy Storage Pumped Hydro	11,996	4,718	618	6,316	355	(11)
Battery ITC	12,055	4,736	621	6,378	331	(11)
EV Load	12,343	4,781	569	6,600	408	(15)
No DSR	12,536	5,229	-	6,883	441	(17)
Extended DSR	11,894	4,637	704	6,251	312	(11)
DSR Discount Rate	11,999	4,709	516	6,425	360	(11)
MT Wind - 150 MW	12,016	4,704	621	6,344	360	(14)
MT Wind 175MW	12,023	4,692	621	6,354	373	(17)
MT Wind - 300 MW	12,063	4,598	569	6,532	404	(39)
Hopkins Ridge Repowering	12,021	4,664	569	6,397	403	(11)
Wild Horse Repowering	12,023	4,693	621	6,347	375	(14)
Add 300 MW Solar	12,027	4,432	569	6,717	383	(74)
No Transmission Redirect	12,108	4,646	621	6,477	374	(11)
More Conservation	12,145	4,431	1,230	6,181	314	(10)

Figure N-76: Annual Revenue Requirements for Sensitivities ($Millions)

	Retire Colstrip 2018 Base	Retire Colstrip 2018 No CO2	Retire Colstrip 2025 Base	Retire Colstrip 2025 No CO2	Retire Colstrip 2030 Base	Retire Colstrip 2030 No CO2
2018	733	709	740	716	727	697
2019	797	760	786	760	773	742
2020	861	826	881	857	867	836
2021	879	840	893	867	881	846
2022	945	836	958	842	944	828
2023	920	817	956	846	940	830
2024	959	837	979	855	963	839
2025	1,001	870	1,021	889	1,005	870
2026	1,034	926	1,017	1,000	1,039	924
2027	1,072	949	1,032	999	1,076	947
2028	1,144	989	1,073	1,031	1,149	989
2029	1,231	1,056	1,156	1,090	1,240	1,062
2030	1,289	1,091	1,233	1,138	1,299	1,110
2031	1,445	1,239	1,362	1,280	1,400	1,320
2032	1,678	1,479	1,628	1,463	1,617	1,459
2033	1,756	1,492	1,716	1,570	1,707	1,554
2034	1,836	1,517	1,772	1,576	1,764	1,563
2035	1,931	1,585	1,862	1,632	1,855	1,622
2036	1,984	1,723	1,923	1,651	1,938	1,668
2037	2,032	1,732	2,005	1,690	2,020	1,710
20-yr NPV	11,574	10,274	11,422	10,525	11,477	10,317
End Effects	370	181	344	123	356	144
Expected Cost	**11,944**	**10,456**	**11,766**	**10,647**	**11,833**	**10,462**

Figure N-77: Annual Revenue Requirements for Sensitivities ($Millions)

	Retire Encogen Base	Retire Ferndale Base	Retire Goldendale Base	Retire Mint Farm Base	Retire Sumas Base	Retire Encogen No CO2	Retire Ferndale No CO2	Retire Goldendale No CO2
2018	730	728	730	730	730	698	698	698
2019	777	773	777	777	777	743	743	743
2020	876	869	876	876	876	839	839	839
2021	890	883	891	891	890	850	850	850
2022	942	962	942	942	942	824	824	824
2023	946	957	946	946	946	825	825	821
2024	971	969	971	971	971	835	835	829
2025	1,015	1,015	1,015	1,015	1,015	870	870	865
2026	1,044	1,046	1,044	1,044	1,044	876	876	873
2027	1,085	1,083	1,085	1,085	1,085	907	907	906
2028	1,139	1,137	1,139	1,139	1,139	950	950	950
2029	1,253	1,250	1,253	1,253	1,253	1,049	1,049	1,049
2030	1,310	1,304	1,310	1,310	1,310	1,088	1,088	1,088
2031	1,458	1,449	1,472	1,472	1,461	1,233	1,234	1,249
2032	1,707	1,704	1,696	1,699	1,698	1,420	1,449	1,432
2033	1,791	1,797	1,780	1,784	1,783	1,457	1,486	1,502
2034	1,846	1,857	1,836	1,839	1,839	1,533	1,532	1,542
2035	1,947	1,955	1,929	1,930	1,941	1,627	1,627	1,620
2036	1,998	2,005	1,981	1,981	1,993	1,774	1,776	1,773
2037	2,036	2,050	2,018	2,019	2,032	1,795	1,811	1,796
20-yr NPV	11,671	11,677	11,653	11,656	11,660	10,202	10,225	10,216
End Effects	304	337	318	318	317	519	562	566
Expected Cost	**11,975**	**12,013**	**11,971**	**11,974**	**11,977**	**10,721**	**10,787**	**10,782**

Figure N-78: Annual Revenue Requirements for Sensitivities ($Millions)

	Retire Mint Farm No CO2	Retire Sumas No CO2	Retire Encogen All Thermal CO2	Retire Ferndale All Thermal CO2	Retire Goldendale All Thermal CO2	Retire Mint Farm All Thermal CO2	Retire Sumas All Thermal CO2
2018	698	698	818	818	818	818	818
2019	743	743	869	869	869	869	869
2020	839	839	968	968	968	968	968
2021	850	850	988	988	989	989	988
2022	824	824	958	958	958	958	958
2023	821	825	959	959	959	959	959
2024	825	835	996	996	996	992	996
2025	862	870	1,041	1,041	1,041	1,038	1,041
2026	869	876	1,077	1,077	1,077	1,075	1,077
2027	903	907	1,120	1,120	1,120	1,116	1,117
2028	947	950	1,175	1,175	1,175	1,172	1,172
2029	1,047	1,049	1,293	1,293	1,293	1,291	1,290
2030	1,086	1,088	1,354	1,354	1,354	1,352	1,352
2031	1,247	1,237	1,536	1,599	1,597	1,594	1,528
2032	1,435	1,452	1,826	1,813	1,807	1,806	1,820
2033	1,509	1,488	1,874	1,862	1,855	1,854	1,869
2034	1,556	1,535	1,930	1,919	1,912	1,917	1,926
2035	1,628	1,628	2,030	2,039	2,039	2,046	2,026
2036	1,780	1,777	2,115	2,134	2,133	2,139	2,112
2037	1,804	1,812	2,156	2,174	2,173	2,179	2,159
20-yr NPV	10,218	10,230	12,325	12,348	12,341	12,335	12,311
End Effects	588	565	343	353	322	329	355
Expected Cost	**10,805**	**10,795**	**12,668**	**12,702**	**12,663**	**12,664**	**12,665**

Figure N-79: Annual Revenue Requirements for Sensitivities ($Millions)

	No New Thermal	High Thermal Cost	Energy Storage Battery	Energy Storage Pumped Hydro	Battery ITC	EV Load	No DSR
2018	737	730	730	730	730	729	698
2019	791	777	777	777	777	775	721
2020	891	876	876	876	876	872	741
2021	906	890	890	890	890	886	754
2022	956	942	942	942	957	970	953
2023	979	955	946	948	951	965	978
2024	976	974	962	968	972	985	1,036
2025	1,005	1,025	1,006	1,013	1,018	1,032	1,063
2026	1,127	1,061	1,036	1,042	1,048	1,074	1,130
2027	1,153	1,095	1,094	1,083	1,089	1,118	1,177
2028	1,194	1,149	1,149	1,138	1,144	1,199	1,255
2029	1,299	1,270	1,238	1,252	1,259	1,289	1,389
2030	1,380	1,326	1,297	1,310	1,316	1,347	1,452
2031	1,607	1,476	1,458	1,457	1,465	1,512	1,623
2032	1,842	1,736	1,687	1,686	1,719	1,747	1,861
2033	1,949	1,790	1,756	1,779	1,785	1,852	1,960
2034	2,033	1,847	1,847	1,837	1,843	1,919	2,031
2035	2,141	1,964	1,937	1,929	1,978	2,024	2,131
2036	2,294	2,029	1,991	1,983	2,027	2,074	2,193
2037	2,358	2,077	2,033	2,025	2,063	2,122	2,253
20-yr NPV	12,299	11,755	11,631	11,641	11,724	11,935	12,095
End Effects	1,045	440	357	355	331	408	441
Expected Cost	**13,343**	**12,194**	**11,988**	**11,996**	**12,055**	**12,343**	**12,536**

Figure N-80: Annual Revenue Requirements for Sensitivities ($Millions)

	Extended DSR Potential	DSR Discount Rate	MT Wind 150 MW	MT Wind 175 MW	MT Wind 300 MW
2018	730	723	730	730	728
2019	777	764	777	777	773
2020	876	870	876	876	869
2021	890	885	890	890	883
2022	942	957	965	970	990
2023	953	951	930	930	947
2024	973	964	947	948	947
2025	1,017	994	996	997	997
2026	1,046	1,049	1,029	1,030	1,028
2027	1,082	1,083	1,063	1,064	1,063
2028	1,147	1,142	1,130	1,122	1,126
2029	1,269	1,233	1,245	1,238	1,239
2030	1,322	1,314	1,304	1,298	1,293
2031	1,451	1,449	1,449	1,446	1,438
2032	1,695	1,696	1,720	1,717	1,725
2033	1,744	1,793	1,787	1,787	1,788
2034	1,796	1,855	1,852	1,852	1,854
2035	1,879	1,950	1,987	1,988	1,991
2036	1,886	2,003	2,037	2,039	2,042
2037	1,919	2,051	2,081	2,083	2,087
20-yr NPV	11,581	11,639	11,655	11,650	11,659
End Effects	312	360	360	373	404
Expected Cost	**11,894**	**11,999**	**12,016**	**12,023**	**12,063**

Figure N-81: Annual Revenue Requirements for Sensitivities ($Millions)

	Hopkins Ridge Repowering	Wild Horse Repowering	Add 300 MW Solar	No Transmission Redirect	More Conservation
2018	728	718	728	729	777
2019	773	771	773	777	870
2020	869	866	869	876	964
2021	883	880	883	890	978
2022	970	965	962	965	1,015
2023	967	955	997	958	1,002
2024	976	970	994	979	998
2025	995	1,010	1,007	1,024	1,033
2026	1,050	1,043	1,057	1,054	1,054
2027	1,083	1,078	1,086	1,086	1,074
2028	1,138	1,137	1,136	1,151	1,102
2029	1,226	1,247	1,220	1,265	1,187
2030	1,306	1,307	1,299	1,321	1,264
2031	1,411	1,462	1,431	1,462	1,391
2032	1,668	1,699	1,671	1,717	1,629
2033	1,767	1,772	1,764	1,784	1,715
2034	1,831	1,856	1,824	1,841	1,773
2035	1,933	1,950	1,923	1,957	1,859
2036	1,987	2,002	1,972	2,005	1,910
2037	2,035	2,047	2,017	2,052	1,955
20-yr NPV	11,618	11,647	11,644	11,733	11,831
End Effects	403	375	383	374	314
Expected Cost	**12,021**	**12,023**	**12,027**	**12,108**	**12,145**

Incremental Portfolio Builds by Year – Sensitivities

Figure N-82: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Colstrip 2018, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	-	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	5
2024	-	-	-	-	-	123	-	21	-	38	9
2025	-	-	239	-	-	-	-	-	-	37	14
2026	-	-	239	-	-	-	-	-	-	36	14
2027	-	-	-	-	-	-	8	4	-	35	5
2028	-	-	239	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	-	478	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	73	-	-	-	19	0
2034	-	-	239	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	76	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,988**	**-**	**-**	**487**	**8**	**25**	**-**	**714**	**67**
Winter	**188**	**-**	**1,988**	**-**	**-**	**-**	**5**	**19**	**-**	**714**	**52**

Figure N-83: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2018, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	50	-	41	3
2024	-	-	-	-	-	29	50	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	413	-	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	413	-	-	-	32	-	-	-	20	1
2032	-	413	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	18	-	-	26	-	-	-	16	1
Total	**188**	**1,652**	**257**	**-**	**-**	**484**	**50**	**50**	**-**	**714**	**148**
Winter	**188**	**1,652**	**257**	**-**	**-**	**-**	**30**	**38**	**-**	**714**	**114**

Figure N-84: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2025, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	-	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	5
2024	-	-	-	-	-	123	-	21	-	38	9
2025	-	-	239	-	-	-	-	-	-	37	14
2026	-	-	717	-	-	-	-	-	-	36	14
2027	-	-	-	-	-	-	8	4	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	239	-	-	-	-	-	-	20	1
2031	-	-	239	-	-	-	-	-	-	20	1
2032	-	-	239	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	73	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	239	-	-	-	-	-	-	16	1
2036	-	-	-	-	-	-	-	-	-	16	1
2037	-	-	80	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,992**	**-**	**-**	**487**	**8**	**25**	**-**	**714**	**67**
Winter	**188**	**-**	**1,992**	**-**	**-**	**-**	**5**	**19**	**-**	**714**	**52**

Figure N-85: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2025, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	29	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	826	-	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	25	-	20	2
2031	-	413	-	-	-	32	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	413	-	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	-	-	-	-	-	-	-	16	2
2037	-	-	-	-	-	26	-	-	-	16	1
Total	**188**	**1,652**	**239**	**-**	**-**	**484**	**25**	**75**	**-**	**714**	**157**
Winter	**188**	**1,652**	**239**	**-**	**-**	**-**	**15**	**57**	**-**	**714**	**121**

Figure N-86: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2030, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	-	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	5
2024	-	-	-	-	-	123	-	21	-	38	9
2025	-	-	239	-	-	-	-	-	-	37	14
2026	-	-	239	-	-	-	-	-	-	36	14
2027	-	-	-	-	-	-	8	4	-	35	5
2028	-	-	239	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	-	717	-	-	-	-	-	-	20	1
2032	-	-	239	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	73	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	239	-	-	-	-	-	-	16	1
2036	-	-	-	-	-	-	-	-	-	16	1
2037	-	-	76	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,988**	**-**	**-**	**487**	**8**	**25**	**-**	**714**	**67**
Winter	**188**	**-**	**1,988**	**-**	**-**	**-**	**5**	**19**	**-**	**714**	**52**

Figure N-87: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2030, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	29	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	413	-	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	25	-	20	2
2031	-	826	-	-	-	32	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	413	-	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	-	-	-	-	-	-	-	16	2
2037	-	-	-	-	-	26	-	-	-	16	1
Total	**188**	**1,652**	**239**	**-**	**-**	**484**	**25**	**75**	**-**	**714**	**157**
Winter	**188**	**1,652**	**239**	**-**	**-**	**-**	**15**	**57**	**-**	**714**	**121**

Figure N-88: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	28	-	41	4
2024	-	-	-	-	-	108	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	478	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	25	-	56	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	30	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	73	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,985**	**-**	**-**	**486**	**25**	**164**	**-**	**714**	**157**
Winter	**188**	**-**	**1,985**	**-**	**-**	**-**	**15**	**125**	**-**	**714**	**121**

Figure N-89: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Ferndale, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	5
2024	-	-	-	-	-	108	-	-	-	38	9
2025	-	-	239	-	-	-	-	-	-	37	14
2026	-	-	239	-	-	-	-	-	-	36	14
2027	-	-	-	-	-	-	25	-	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	-	478	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	25	-	60	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	25	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	80	-	-	25	-	-	-	16	0
Total	**188**	**-**	**2,231**	**-**	**-**	**486**	**25**	**85**	**-**	**714**	**67**
Winter	**188**	**-**	**2,231**	**-**	**-**	**-**	**15**	**64**	**-**	**714**	**52**

Figure N-90: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Goldendale, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	28	-	41	4
2024	-	-	-	-	-	108	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	717	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	25	-	-	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	43	-	-	25	-	-	-	16	1
Total	**188**	**-**	**2,194**	**-**	**-**	**486**	**25**	**78**	**-**	**714**	**157**
Winter	**188**	**-**	**2,194**	**-**	**-**	**-**	**15**	**59**	**-**	**714**	**121**

Figure N-91: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Mint Farm, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	28	-	41	4
2024	-	-	-	-	-	108	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	717	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	25	-	-	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	48	-	-	25	-	-	-	16	1
Total	**188**	**-**	**2,199**	**-**	**-**	**486**	**25**	**78**	**-**	**714**	**157**
Winter	**188**	**-**	**2,199**	**-**	**-**	**-**	**15**	**59**	**-**	**714**	**121**

Figure N-92: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Sumas, Base Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	28	-	41	4
2024	-	-	-	-	-	108	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	478	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	25	-	25	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	29	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	73	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,985**	**-**	**-**	**486**	**25**	**132**	**-**	**714**	**157**
Winter	**188**	**-**	**1,985**	**-**	**-**	**-**	**15**	**101**	**-**	**714**	**121**

Figure N-93: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	29	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	25	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	478	-	-	32	-	30	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	72	-	-	-	19	1
2034	-	-	239	-	-	-	-	-	25	17	1
2035	-	-	-	-	-	-	-	-	76	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	11	-	-	26	-	-	-	16	1
Total	**188**	**-**	**1,923**	**-**	**-**	**484**	**25**	**80**	**126**	**714**	**157**
Winter	**188**	**-**	**1,923**	**-**	**-**	**-**	**15**	**61**	**123**	**714**	**121**

Figure N-94: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Ferndale, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	29	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	25	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	478	-	-	32	-	30	-	20	1
2032	-	-	239	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	25	17	1
2035	-	-	-	-	-	-	-	-	76	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	123	-	-	26	-	-	-	16	1
Total	**188**	**-**	**2,035**	**-**	**-**	**484**	**25**	**80**	**126**	**714**	**157**
Winter	**188**	**-**	**2,035**	**-**	**-**	**-**	**15**	**61**	**123**	**714**	**121**

Figure N-95: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Goldendale, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	25	-	-	41	4
2024	-	-	-	-	-	29	-	28	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	717	-	-	32	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	239	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	43	-	-	26	-	-	-	16	1
Total	**188**	**-**	**2,194**	**-**	**-**	**484**	**25**	**53**	**-**	**714**	**157**
Winter	**188**	**-**	**2,194**	**-**	**-**	**-**	**15**	**40**	**-**	**714**	**121**

Figure N-96: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Mint Farm, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	25	-	-	41	4
2024	-	-	-	-	-	29	-	-	26	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	717	-	-	32	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	239	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	48	-	-	26	-	-	-	16	1
Total	**188**	**-**	**2,199**	**-**	**-**	**484**	**25**	**25**	**26**	**714**	**157**
Winter	**188**	**-**	**2,199**	**-**	**-**	**-**	**15**	**19**	**26**	**714**	**121**

Figure N-97: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Sumas, No CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	29	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	25	35	6
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	478	-	-	32	-	30	-	20	1
2032	-	-	239	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	25	17	1
2035	-	-	-	-	-	-	-	-	76	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	123	-	-	26	-	-	-	16	1
Total	**188**	**-**	**2,035**	**-**	**-**	**484**	**25**	**80**	**126**	**714**	**157**
Winter	**188**	**-**	**2,035**	**-**	**-**	**-**	**15**	**61**	**123**	**714**	**121**

Figure N-98: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, All Thermal CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	200	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	413	-	-	-	-	-	-	28	20	1
2032	-	413	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	-	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	66	-	-	25	-	-	-	16	1
Total	**188**	**1,239**	**783**	**-**	**-**	**490**	**25**	**75**	**28**	**714**	**157**
Winter	**188**	**1,239**	**783**	**-**	**-**	**-**	**15**	**57**	**27**	**714**	**121**

Figure N-99: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Ferndale, All Thermal CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	200	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	826	-	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	-	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	68	16	1
2036	-	413	-	-	-	-	-	-	44	16	2
2037	-	-	93	-	-	25	-	-	-	16	1
Total	**188**	**1,239**	**810**	**-**	**-**	**490**	**25**	**75**	**112**	**714**	**157**
Winter	**188**	**1,239**	**810**	**-**	**-**	**-**	**15**	**57**	**110**	**714**	**121**

Figure N-100: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Goldendale, All Thermal CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	200	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	826	-	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	-	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	77	16	1
2036	-	413	-	-	-	-	-	-	44	16	2
2037	-	-	93	-	-	25	-	-	-	16	1
Total	**188**	**1,239**	**810**	**-**	**-**	**490**	**25**	**75**	**122**	**714**	**157**
Winter	**188**	**1,239**	**810**	**-**	**-**	**-**	**15**	**57**	**119**	**714**	**121**

Figure N-101: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Mint Farm, All Thermal CO_2 Scenario

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	200	-	-	32	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	826	-	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	-	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	85	16	1
2036	-	413	-	-	-	-	-	-	44	16	2
2037	-	-	93	-	-	25	-	-	-	16	1
Total	**188**	**1,239**	**810**	**-**	**-**	**490**	**-**	**50**	**161**	**714**	**157**
Winter	**188**	**1,239**	**810**	**-**	**-**	**-**	**-**	**38**	**158**	**714**	**121**

Figure N-102: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Sumas All Thermal CO_2

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	25	-	41	4
2024	-	-	-	-	-	200	25	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	25	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	413	-	-	-	-	-	-	-	20	1
2032	-	413	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	-	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	63	-	-	25	-	-	-	16	1
Total	**188**	**1,239**	**780**	**-**	**-**	**490**	**25**	**50**	**25**	**714**	**157**
Winter	**188**	**1,239**	**780**	**-**	**-**	**-**	**15**	**38**	**25**	**714**	**121**

Figure N-103: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: No New Thermal

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	30	15
2019	-	-	-	-	-	-	-	-	-	58	30
2020	-	-	-	-	-	-	-	-	-	105	43
2021	-	-	-	-	-	-	-	-	-	101	41
2022	-	-	-	-	-	35	-	-	-	46	13
2023	-	-	-	-	300	-	-	-	-	42	4
2024	-	-	-	-	-	-	-	-	-	40	9
2025	-	-	-	-	-	-	-	25	-	38	13
2026	-	-	-	-	-	-	25	125	201	37	15
2027	-	-	-	-	-	-	25	-	12	37	6
2028	-	-	-	-	-	-	-	-	11	29	0
2029	-	-	-	-	-	-	-	-	76	21	0.5
2030	-	-	-	-	-	-	-	-	83	20	2.1
2031	-	-	-	-	-	-	-	-	336	20	1.9
2032	-	-	-	-	-	-	-	-	78	20	2.0
2033	-	-	-	-	-	-	-	-	79	19	1.3
2034	-	-	-	-	-	-	-	-	80	17	1.6
2035	-	-	-	-	-	-	-	-	87	16	1.8
2036	-	-	-	-	-	-	-	-	465	16	2.6
2037	-	-	-	-	-	25	-	-	104	16	1.1
Total	**188**	**-**	**-**	**-**	**300**	**60**	**50**	**150**	**1,612**	**728**	**203**
Winter	**188**	**-**	**-**	**-**	**136**	**-**	**30**	**114**	**1582**	**728**	**156**

Figure N-104: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Higher Thermal Cost

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	52	-	41	4
2024	-	-	-	-	-	108	-	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	25	-	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	(0)
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	239	-	-	-	-	-	33	20	1
2032	-	-	239	-	-	25	-	-	-	20	1
2033	-	-	-	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	88	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	86	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,759**	**-**	**-**	**486**	**25**	**77**	**120**	**714**	**157**
Winter	**188**	**-**	**1,759**	**-**	**-**	**-**	**15**	**59**	**118**	**714**	**121**

Figure N-105: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Energy Storage – Battery

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	50	-	41	3
2024	-	-	-	-	-	112	25	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	-	239	-	-	-	-	-	-	36	12
2027	-	-	239	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0.0
2030	-	-	-	-	-	-	-	-	-	20	1.4
2031	-	-	478	-	-	-	-	-	-	20	1.2
2032	-	-	-	-	-	25	-	-	-	20	1.4
2033	-	-	-	-	-	59	-	-	-	19	0.6
2034	-	-	239	-	-	-	-	-	-	17	0.9
2035	-	-	-	-	-	-	-	-	-	16	1.1
2036	-	-	478	-	-	-	-	-	-	16	1.8
2037	-	-	-	-	-	25	-	-	-	16	0.6
Total	**188**	**-**	**1,912**	**-**	**-**	**486**	**25**	**50**	**-**	**714**	**148**
Winter	**188**	**-**	**1,912**	**-**	**-**	**-**	**15**	**38**	**-**	**714**	**114**

Figure N-106: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Energy Storage - Pumped Storage

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	-	50	41	3
2024	-	-	-	-	-	108	-	25	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	-	239	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	25	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	(0.1)
2029	-	-	239	-	-	-	-	-	-	20	0.0
2030	-	-	-	-	-	-	-	-	-	20	1.4
2031	-	-	353	-	-	-	-	-	-	20	1.2
2032	-	-	-	-	-	25	-	-	-	20	1.4
2033	-	-	239	-	-	63	-	-	-	19	0.6
2034	-	-	-	-	-	-	-	-	-	17	0.9
2035	-	-	-	-	-	-	-	-	-	16	1.1
2036	-	-	478	-	-	-	-	-	-	16	1.8
2037	-	-	71	-	-	25	-	-	-	16	0.6
Total	**188**	**-**	**1,858**	**-**	**-**	**486**	**-**	**50**	**50**	**714**	**148**
Winter	**188**	**-**	**1,858**	**-**	**-**	**-**	**-**	**38**	**50**	**714**	**114**

Figure N-107: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Battery ITC

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	108	-	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	25	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	239	-	-	-	-	37	-	20	1
2032	-	-	239	-	-	25	-	-	-	20	1
2033	-	-	-	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	113	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	73	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,746**	**-**	**-**	**486**	**-**	**200**	**-**	**714**	**157**
Winter	**188**	**-**	**1,746**	**-**	**-**	**-**	**-**	**152**	**-**	**714**	**121**

Figure N-108: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Electric Vehicle Load

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	52	-	-	-	45	1
2023	-	-	-	-	-	221	-	-	-	41	4
2024	-	-	-	-	-	148	-	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	12
2026	-	-	239	-	-	-	-	25	-	36	12
2027	-	-	-	-	-	-	-	25	-	35	4
2028	-	-	239	-	-	-	-	-	-	28	(0)
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	-	478	-	-	-	-	-	-	20	0
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	239	-	-	85	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	0
2035	-	-	-	-	-	-	-	-	34	16	0
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	102	-	-	25	-	-	-	16	0
Total	**188**	**-**	**2,253**	**-**	**-**	**530**	**-**	**50**	**34**	**714**	**58**
Winter	**188**	**-**	**2,253**	**-**	**-**	**-**	**-**	**38**	**33**	**714**	**45**

Figure N-109: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: No DSR

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	239	-	-	114	-	27	-	-	-
2023	-	-	-	-	-	197	25	54	-	-	-
2024	-	-	239	-	-	191	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	478	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	239	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	478	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	239	-	-	90	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	478	-	-	-	-	-	-	-	-
2037	-	-	87	-	-	25	-	-	-	-	-
Total	**188**	**-**	**2,477**	**-**	**-**	**616**	**25**	**81**	**-**	**-**	**-**
Winter	**188**	**-**	**2,477**	**-**	**-**	**-**	**15**	**61**	**-**	**-**	**-**

Figure N-110: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Extended DSR Potential

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	47	-	41	4
2024	-	-	-	-	-	109	-	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	25	-	-	35	6
2028	-	-	-	-	-	-	-	-	-	36	-
2029	-	-	239	-	-	-	-	-	-	35	0
2030	-	-	-	-	-	-	-	-	-	35	2
2031	-	-	239	-	-	-	-	-	-	37	1
2032	-	-	239	-	-	-	-	-	-	37	1
2033	-	-	-	-	-	49	-	-	-	37	1
2034	-	-	-	-	-	-	-	-	-	37	1
2035	-	-	-	-	-	-	-	-	-	37	1
2036	-	-	478	-	-	-	-	-	-	37	2
2037	-	-	28	-	-	25	-	-	-	38	1
Total	**188**	**-**	**1,701**	**-**	**-**	**449**	**25**	**72**	**-**	**886**	**157**
Winter	**188**	**-**	**1,701**	**-**	**-**	**-**	**15**	**55**	**-**	**886**	**121**

Figure N-111: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: DSR Discount Rate

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	28	2
2019	-	-	-	-	-	-	-	-	-	55	4
2020	-	-	-	-	-	-	-	-	-	101	4
2021	-	-	-	-	-	-	-	-	-	97	3
2022	-	-	239	-	-	45	-	-	-	43	1
2023	-	-	-	-	-	224	-	-	-	39	4
2024	-	-	-	-	-	113	-	-	-	36	8
2025	-	-	-	-	-	-	-	25	-	35	12
2026	-	-	478	-	-	-	-	-	-	34	12
2027	-	-	-	-	-	-	-	-	-	34	4
2028	-	-	-	-	-	-	-	-	-	27	(0)
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	239	-	-	-	-	-	-	20	1
2031	-	-	239	-	-	-	-	-	-	20	0
2032	-	-	-	-	-	25	-	29	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	0
2035	-	-	-	-	-	-	-	25	-	16	0
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	67	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,979**	**-**	**-**	**494**	**-**	**79**	**-**	**693**	**58**
Winter	**188**	**-**	**1,979**	**-**	**-**	**-**	**-**	**60**	**-**	**693**	**45**

Figure N-112: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: MT Wind - 150 MW

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	150	-	-	-	-	45	9
2023	-	-	-	-	-	33	-	-	-	41	4
2024	-	-	-	-	-	98	-	-	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	-	-	25	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	239	-	-	-	-	25	-	20	1
2032	-	-	239	-	-	25	-	-	-	20	1
2033	-	-	-	-	-	56	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	109	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	73	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,746**	**-**	**150**	**237**	**-**	**159**	**-**	**714**	**157**
Winter	**188**	**-**	**1,746**	**-**	**68**	**-**	**-**	**121**	**-**	**714**	**121**

Figure N-113: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: MT Wind - 175 MW

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	175	-	-	-	-	45	9
2023	-	-	-	-	-	-	-	-	-	41	4
2024	-	-	-	-	-	106	-	-	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	239	-	-	-	-	31	-	20	1
2032	-	-	239	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	66	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	113	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	73	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,746**	**-**	**175**	**197**	**-**	**144**	**-**	**714**	**157**
Winter	**188**	**-**	**1,746**	**-**	**86**	**-**	**-**	**109**	**-**	**714**	**121**

Figure N-114: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: MT Wind - 300 MW

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	-	-	300	-	-	-	-	45	1
2023	-	-	-	-	-	-	-	-	-	41	4
2024	-	-	-	-	-	-	-	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	12
2026	-	-	239	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	25	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	-	239	-	-	-	-	29	-	20	0
2032	-	-	239	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	-	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	0
2035	-	-	-	-	-	-	-	113	-	16	0
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	74	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,747**	**-**	**300**	**25**	**-**	**168**	**-**	**714**	**58**
Winter	**188**	**-**	**1,747**	**-**	**136**	**-**	**-**	**128**	**-**	**714**	**45**

Figure N-115: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Hopkins Ridge Repowering

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	108	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	478	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	239	-	-	-	-	-	-	20	1
2031	-	-	239	-	-	-	-	-	-	20	0
2032	-	-	-	-	-	25	-	25	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	0
2035	-	-	-	-	-	-	-	25	-	16	0
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	67	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,979**	**-**	**-**	**486**	**-**	**50**	**-**	**714**	**58**
Winter	**188**	**-**	**1,979**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**45**

Figure N-116: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Wild Horse Repowering

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	21	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	25	-	-	-	45	9
2023	-	-	-	-	-	217	-	-	-	41	4
2024	-	-	-	-	-	122	-	5	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	5	7	-	35	6
2028	-	-	-	-	-	-	-	14	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	478	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	72	-	-	-	19	1
2034	-	-	239	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	58	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,970**	**21**	**-**	**462**	**5**	**25**	**-**	**714**	**157**
Winter	**188**	**-**	**1,970**	**3**	**-**	**-**	**-**	**19**	**-**	**714**	**121**

Figure N-117: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Add 300 MW Solar

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	2
2019	-	-	-	-	-	-	-	-	-	57	4
2020	-	-	-	-	-	-	-	-	-	103	4
2021	-	-	-	-	-	-	-	-	-	99	3
2022	-	-	239	-	-	40	-	-	-	45	1
2023	-	-	-	-	-	525	-	-	-	41	4
2024	-	-	-	-	-	108	-	-	-	38	8
2025	-	-	-	-	-	-	-	-	-	37	12
2026	-	-	478	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	4
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	239	-	-	-	-	-	-	20	1
2031	-	-	239	-	-	-	-	-	-	20	0
2032	-	-	-	-	-	25	-	25	-	20	1
2033	-	-	239	-	-	63	-	-	-	19	0
2034	-	-	-	-	-	-	-	-	-	17	0
2035	-	-	-	-	-	-	-	25	-	16	0
2036	-	-	478	-	-	-	-	-	-	16	1
2037	-	-	67	-	-	25	-	-	-	16	0
Total	**188**	**-**	**1,979**	**-**	**-**	**786**	**-**	**50**	**-**	**714**	**58**
Winter	**188**	**-**	**1,979**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**45**

Figure N-118: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: No Transmission Redirect

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	239	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	-	-	41	4
2024	-	-	-	-	-	108	-	25	-	38	10
2025	-	-	239	-	-	-	-	-	-	37	13
2026	-	-	239	-	-	-	-	-	-	36	15
2027	-	-	-	-	-	-	-	-	-	35	6
2028	-	-	-	-	-	-	-	25	-	28	-
2029	-	-	239	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	2
2031	-	-	239	-	-	-	-	-	25	20	1
2032	-	-	239	-	-	25	-	-	-	20	1
2033	-	-	-	-	-	63	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	239	-	-	-	-	-	-	16	1
2036	-	-	239	-	-	-	-	-	64	16	2
2037	-	-	93	-	-	25	-	-	-	16	1
Total	**188**	**-**	**2,005**	**-**	**-**	**486**	**-**	**50**	**89**	**714**	**157**
Winter	**188**	**-**	**2,005**	**-**	**-**	**-**	**-**	**38**	**87**	**714**	**121**

Figure N-119: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: More Conservation

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	36	11
2019	-	-	-	-	-	-	-	-	-	67	21
2020	-	-	-	-	-	-	-	-	-	114	30
2021	-	-	-	-	-	25	-	-	-	110	29
2022	-	-	-	-	-	-	-	-	-	56	9
2023	-	-	-	-	-	221	-	-	-	51	4
2024	-	-	-	-	-	78	-	-	-	48	10
2025	-	-	239	-	-	-	-	-	-	47	13
2026	-	-	239	-	-	-	-	-	-	46	15
2027	-	-	-	-	-	-	-	-	-	45	6
2028	-	-	-	-	-	-	-	-	-	34	-
2029	-	-	-	-	-	-	-	51	-	23	0
2030	-	-	239	-	-	-	-	-	-	22	2
2031	-	-	239	-	-	-	-	-	-	22	1
2032	-	-	-	-	-	25	-	41	-	22	1
2033	-	-	239	-	-	58	-	-	-	20	1
2034	-	-	-	-	-	-	-	-	-	18	1
2035	-	-	-	-	-	-	-	-	-	17	1
2036	-	-	478	-	-	-	-	-	-	16	2
2037	-	-	72	-	-	25	-	-	-	16	1
Total	**188**	**-**	**1,745**	**-**	**-**	**431**	**-**	**92**	**-**	**830**	**157**
Winter	**188**	**-**	**1,745**	**-**	**-**	**-**	**-**	**70**	**-**	**830**	**121**

Portfolio CO_2 Emissions – Sensitivities

Figure N-120: Total Portfolio CO_2 Emissions

Emission PSE Portfolio - Sensitivity (Millions Tons)

	Retire Colstrip 2018 Base	Retire Colstrip 2018 No CO2	Retire Colstrip 2025 Base	Retire Colstrip 2025 No CO2	Retire Colstrip 2030 Base	Retire Colstrip 2030 No CO2
2018	12.30	12.66	12.05	12.66	12.30	12.90
2019	12.02	9.66	11.71	12.31	12.02	12.61
2020	11.64	9.49	11.31	11.83	11.64	12.15
2021	11.17	9.14	10.96	11.69	11.17	11.89
2022	6.03	9.11	6.72	10.28	6.03	9.68
2023	6.09	9.82	7.37	9.82	6.09	8.65
2024	6.22	9.85	7.74	9.85	6.22	8.43
2025	6.84	10.17	8.50	10.17	6.84	8.63
2026	7.27	9.38	7.69	6.39	7.27	9.24
2027	7.51	9.22	7.95	6.45	7.51	9.05
2028	7.73	9.55	8.14	6.54	7.73	9.38
2029	8.14	9.53	8.59	6.74	8.14	9.32
2030	8.24	9.73	8.79	6.91	8.24	9.50
2031	8.65	10.37	9.19	7.35	6.24	7.34
2032	9.44	11.00	10.13	8.05	7.03	7.93
2033	9.58	11.28	10.28	8.24	7.13	8.25
2034	9.53	11.21	10.17	8.40	7.29	8.42
2035	9.49	11.37	10.22	8.53	7.45	8.53
2036	7.65	8.71	8.27	8.71	7.63	8.69
2037	7.84	8.79	8.44	8.79	7.82	8.76

Figure N-121: Total Portfolio CO_2 Emissions

Emission PSE Portfolio - Sensitivity (Millions Tons)

	Retire Encogen Base	Retire Ferndale Base	Retire Goldendale Base	Retire Mint Farm Base	Retire Sumas Base
2018	12.30	12.30	12.30	12.30	12.30
2019	12.02	12.02	12.02	12.02	12.02
2020	11.64	11.64	11.64	11.64	11.64
2021	11.17	11.17	11.17	11.17	11.17
2022	6.03	6.06	6.03	6.03	6.03
2023	6.09	6.12	6.09	6.09	6.09
2024	6.23	6.27	6.23	6.23	6.23
2025	6.85	6.89	6.85	6.85	6.85
2026	7.28	7.32	7.28	7.28	7.28
2027	7.52	7.56	7.52	7.52	7.52
2028	7.70	7.73	7.70	7.70	7.70
2029	8.14	8.18	8.14	8.14	8.14
2030	8.24	8.29	8.24	8.24	8.24
2031	8.65	8.65	8.59	8.79	8.57
2032	9.41	9.42	9.39	9.62	9.34
2033	9.62	9.63	9.63	9.91	9.56
2034	9.53	9.54	9.52	9.81	9.45
2035	9.49	9.50	9.45	9.74	9.42
2036	7.65	7.66	7.61	7.89	7.58
2037	7.84	7.86	7.80	8.10	7.77

Figure N-122: Total Portfolio CO_2 Emissions

Emission PSE Portfolio - Sensitivity (Millions Tons)

	Retire Encogen No CO2	Retire Ferndale No CO2	Retire Goldendale No CO2	Retire Mint Farm No CO2	Retire Sumas No CO2
2018	12.90	12.90	12.90	12.90	12.90
2019	12.61	12.61	12.61	12.61	12.61
2020	12.15	12.15	12.15	12.15	12.15
2021	11.89	11.89	11.89	11.89	11.89
2022	9.68	9.68	9.68	9.68	9.68
2023	8.65	8.65	8.65	8.65	8.65
2024	8.43	8.43	8.43	8.43	8.43
2025	8.63	8.63	8.63	8.63	8.63
2026	9.01	9.01	9.01	9.01	9.01
2027	8.82	8.82	8.82	8.82	8.82
2028	9.14	9.14	9.14	9.14	9.14
2029	9.10	9.10	9.10	9.10	9.10
2030	9.30	9.30	9.30	9.30	9.30
2031	9.76	9.59	9.63	9.68	9.71
2032	10.14	9.97	10.01	10.07	10.09
2033	10.42	10.26	10.33	10.49	10.38
2034	10.38	10.18	10.27	10.39	10.32
2035	10.54	10.34	10.42	10.48	10.48
2036	7.79	7.58	7.65	7.71	7.72
2037	7.82	7.63	7.70	7.73	7.77

Figure N-123: Total Portfolio CO_2 Emissions

Emission PSE Portfolio - Sensitivity (Millions Tons)

	Retire Encogen All Thermal CO2	Retire Ferndale All Thermal CO2	Retire Goldendale All Thermal CO2	Retire Mint Farm All Thermal CO2	Retire Sumas All Thermal CO2
2018	7.62	7.62	7.62	7.62	7.62
2019	7.43	7.43	7.43	7.43	7.43
2020	6.82	6.82	6.82	6.82	6.82
2021	6.76	6.76	6.76	6.76	6.76
2022	6.84	6.84	6.84	6.84	6.84
2023	6.82	6.82	6.82	6.82	6.82
2024	6.97	6.97	6.97	6.97	6.97
2025	7.53	7.53	7.53	7.53	7.53
2026	7.59	7.59	7.59	7.59	7.59
2027	7.78	7.78	7.78	7.78	7.78
2028	8.00	8.00	8.00	8.00	8.00
2029	8.18	8.18	8.18	8.18	8.18
2030	8.28	8.28	8.28	8.28	8.28
2031	8.92	8.70	9.61	9.61	8.92
2032	9.61	9.26	9.96	9.96	9.60
2033	9.78	9.50	10.08	10.08	9.76
2034	9.68	9.37	9.99	9.99	9.66
2035	9.62	9.19	10.00	10.00	9.61
2036	7.48	7.07	7.84	7.84	7.45
2037	7.49	7.07	7.86	7.86	7.45

Figure N-124: Total Portfolio CO_2 Emissions

Emission PSE Portfolio - Sensitivity (Millions Tons)

	No New Thermal	High Thermal Cost	Energy Storage Battery	Energy Storage Pumped Hydro	Batteries ITC	EV Load	No DSR
2018	12.30	12.30	12.30	12.30	12.30	12.30	12.35
2019	12.01	12.02	12.02	12.02	12.02	12.02	12.15
2020	11.63	11.64	11.64	11.64	11.64	11.64	11.84
2021	11.15	11.17	11.17	11.17	11.17	11.17	11.42
2022	6.01	6.03	6.03	6.03	6.03	6.05	6.30
2023	5.90	6.09	6.09	6.09	6.09	6.12	6.43
2024	6.12	6.23	6.23	6.23	6.23	6.23	6.60
2025	6.69	6.85	6.85	6.85	6.85	6.86	7.26
2026	7.07	7.28	7.28	7.28	7.28	7.29	7.79
2027	7.31	7.52	7.55	7.52	7.52	7.53	8.08
2028	7.48	7.70	7.73	7.70	7.70	7.74	8.28
2029	7.89	8.14	8.14	8.14	8.14	8.15	8.75
2030	7.95	8.24	8.24	8.24	8.24	8.27	8.89
2031	8.25	8.61	8.65	8.63	8.61	8.68	9.33
2032	9.03	9.42	9.42	9.40	9.42	9.46	10.13
2033	9.21	9.58	9.57	9.62	9.58	9.66	10.35
2034	9.06	9.47	9.52	9.50	9.47	9.55	10.28
2035	9.01	9.43	9.49	9.46	9.43	9.52	10.26
2036	7.01	7.58	7.64	7.61	7.58	7.68	8.44
2037	7.11	7.77	7.81	7.80	7.77	7.88	8.66

Figure N-125: Total Portfolio CO_2 Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

	Extended DSR Potential	DSR Discount Rate	MT Wind 150 MW	MT Wind 175 MW	MT Wind 300 MW
2018	12.30	12.30	12.30	12.30	12.30
2019	12.02	12.03	12.02	12.02	12.02
2020	11.64	11.66	11.64	11.64	11.64
2021	11.17	11.18	11.17	11.17	11.17
2022	6.03	6.08	5.90	5.87	5.74
2023	6.09	6.14	6.09	6.08	5.95
2024	6.23	6.29	6.24	6.23	6.17
2025	6.85	6.89	6.86	6.85	6.78
2026	7.28	7.36	7.28	7.27	7.21
2027	7.52	7.60	7.53	7.52	7.45
2028	7.68	7.77	7.70	7.69	7.63
2029	8.10	8.18	8.15	8.14	8.07
2030	8.17	8.34	8.25	8.24	8.17
2031	8.51	8.70	8.61	8.60	8.53
2032	9.31	9.46	9.42	9.43	9.36
2033	9.44	9.67	9.58	9.58	9.56
2034	9.29	9.57	9.47	9.47	9.45
2035	9.21	9.53	9.43	9.43	9.41
2036	7.32	7.68	7.58	7.58	7.56
2037	7.45	7.87	7.77	7.77	7.75

Figure N-126: Total Portfolio CO_2 Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

	Hopkins Ridge Repowering	Wild Horse Repowering	Add 300 MW Solar	No Transmission Redirect	More Conservation
2018	12.30	12.30	12.30	12.30	12.29
2019	12.02	12.02	12.02	12.02	11.97
2020	11.64	11.63	11.64	11.64	11.56
2021	11.17	11.15	11.17	11.17	11.04
2022	6.06	6.02	6.06	6.06	5.90
2023	6.12	6.09	5.92	6.12	5.94
2024	6.27	6.22	6.06	6.27	6.08
2025	6.86	6.84	6.65	6.89	6.66
2026	7.33	7.27	7.12	7.32	7.07
2027	7.57	7.51	7.36	7.56	7.29
2028	7.73	7.69	7.52	7.73	7.44
2029	8.14	8.13	7.94	8.18	7.85
2030	8.30	8.23	8.09	8.29	7.99
2031	8.66	8.64	8.45	8.66	8.34
2032	9.42	9.43	9.21	9.47	9.11
2033	9.63	9.58	9.43	9.63	9.32
2034	9.53	9.53	9.32	9.52	9.20
2035	9.49	9.49	9.29	9.54	9.15
2036	7.64	7.65	7.44	7.64	7.30
2037	7.83	7.83	7.63	7.84	7.48

7. STOCHASTIC ANALYSIS RESULTS

Figure N-127: Revenue Requirement with Input Simulations – 1,000 Trials

Expected Portfolio Cost ($Millions)	Risk Simulation - 1000 Trials							
	Resource Plan	Base Portfolio (Frame Peakers)	Base + No CO2 Portfolio (CCCT)	No DSR	Add 300 MW Solar	No Transmission Redirect	No New Thermal	More Conservation (Bundle 5)
Minimum	7.46	7.19	8.29	6.84	6.93	7.17	9.92	7.92
1st Quartile (P25)	10.09	10.03	10.55	10.34	10.06	10.12	12.06	10.31
Mean	10.57	10.52	11.13	10.84	10.54	10.62	12.69	10.81
Median (P50)	10.60	10.55	11.19	10.89	10.60	10.66	12.70	10.82
3rd Quartile (P75)	11.14	11.08	11.71	11.42	11.09	11.18	13.44	11.36
TVar90	11.84	11.79	12.50	12.18	11.80	11.89	14.65	12.06
Maximum	12.89	12.80	13.33	13.03	12.61	12.86	16.34	13.15

8. CARBON ABATEMENT ANALYSIS RESULTS

Expected Portfolio Costs – Carbon Abatement

This table summarizes the expected costs of the different carbon abatement analysis.

Figure N-128: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenario Expected Cost for All Portfolios

Scenario	NPV to 2018 ($Millions)					
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Incremental Rev. Req.	Generic End Effects	REC Revenue
Add 300 MW Wind No CO2	10,841	738	618	9,163	328	(5)
Add 300 MW Solar No CO2	10,523	657	618	9,115	142	(9)
50%RPS	11,707	(37)	618	10,364	794	(32)
CAR Cap on WA CCCT	10,562	1,393	420	8,839	(82)	(9)
Additional Conservation – Incremental	10,645	358	1,230	8,908	156	(6)
Additional Conservation – All	26,971	(889)	20,927	6,858	112	(37)
Early Retirement of Colstrip 3&4 [1]	10,647	656	621	9,252	123	(5)

NOTE

1. *This is the same portfolio as "Retire Colstrip 2025 No CO_2" in Figure N-73.*

Figure N-129: Annual Revenue Requirements for Optimal Portfolio ($Millions)

	Add 300 Wind No CO2	Add 300 Solar No CO2	50% RPS	Cap Gas	Additional Conservation Incremental	Additional Conservation All	Early Retirement of Colstrip 3&4
2018	698	698	698	691	745	1,987	716
2019	743	743	743	723	836	3,376	760
2020	839	839	839	822	927	3,569	857
2021	850	850	850	839	938	3,656	867
2022	824	824	894	899	899	3,678	842
2023	894	886	884	897	885	3,613	846
2024	890	884	960	903	870	3,318	855
2025	916	907	965	913	896	3,057	889
2026	966	955	1,003	972	940	2,813	1,000
2027	983	971	1,013	999	947	2,534	999
2028	1,018	996	1,062	1,034	955	1,974	1,031
2029	1,084	1,063	1,142	1,110	1,010	1,527	1,090
2030	1,118	1,097	1,186	1,153	1,108	1,405	1,138
2031	1,262	1,242	1,342	1,292	1,174	1,314	1,280
2032	1,446	1,480	1,527	1,492	1,410	1,379	1,463
2033	1,559	1,490	1,696	1,573	1,430	1,295	1,570
2034	1,575	1,513	1,678	1,601	1,450	1,114	1,576
2035	1,640	1,579	1,712	1,678	1,501	1,028	1,632
2036	1,774	1,716	1,822	1,815	1,637	1,093	1,650
2037	1,778	1,722	1,844	1,823	1,647	1,042	1,690
20-yr NPV	10,514	10,381	10,913	10,643	10,489	26,859	10,525
End Effects	328	142	794	(82)	156	112	123
Expected Cost	**10,841**	**10,523**	**11,707**	**10,562**	**10,645**	**26,971**	**10,647**

Incremental Portfolio Builds by Year – Carbon Abatement

Figure N-130: Incremental Portfolio Builds by Year (nameplate MW)

Carbon Abatement: Add 300 MW Wind No CO_2

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	-	-	41	3
2024	-	-	-	-	-	29	-	25	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	413	-	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	413	-	-	-	32	-	-	-	20	1
2032	-	-	-	-	-	-	-	25	-	20	1
2033	-	413	-	-	-	72	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	-	-	-	26	-	-	-	16	1
Total	**188**	**1,652**	**239**	**-**	**-**	**484**	**-**	**50**	**-**	**714**	**148**
Winter	**188**	**1,652**	**239**	**-**	**-**	**-**	**-**	**38**	**-**	**714**	**114**

Figure N-131: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Add 300 MW Solar No CO_2

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	40	-	-	-	45	9
2023	-	-	-	-	-	225	-	50	-	41	3
2024	-	-	-	-	-	90	50	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	413	-	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	-	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	0
2030	-	-	-	-	-	-	-	-	-	20	1
2031	-	413	-	-	-	32	-	-	-	20	1
2032	-	413	-	-	-	-	-	-	-	20	1
2033	-	-	-	-	-	73	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	18	-	-	25	-	-	-	16	1
Total	**188**	**1,652**	**257**	**-**	**-**	**486**	**50**	**50**	**-**	**714**	**148**
Winter	**188**	**1,652**	**257**	**-**	**-**	**-**	**30**	**38**	**-**	**714**	**114**

Figure N-132: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: 50% Washington RPS

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	29	11
2019	-	-	-	-	-	-	-	-	-	57	21
2020	-	-	-	-	-	-	-	-	-	103	30
2021	-	-	-	-	-	-	-	-	-	99	29
2022	-	-	-	-	-	435	-	-	-	45	9
2023	-	-	-	-	-	224	-	50	-	41	3
2024	-	-	-	-	-	579	50	-	-	38	8
2025	-	-	239	-	-	-	-	-	-	37	11
2026	-	413	-	-	-	-	-	-	-	36	12
2027	-	-	-	-	-	-	-	-	-	35	5
2028	-	-	-	-	-	184	-	-	-	28	-
2029	-	-	-	-	-	157	-	-	-	20	0
2030	-	-	-	-	-	149	-	-	-	20	1
2031	-	413	-	-	-	172	-	-	-	20	1
2032	-	-	-	-	-	174	-	25	-	20	1
2033	-	413	-	-	-	780	-	-	-	19	1
2034	-	-	-	-	-	-	-	-	-	17	1
2035	-	-	-	-	-	-	-	-	-	16	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	-	-	-	231	-	-	-	16	1
Total	**188**	**1,652**	**239**	**-**	**-**	**3,086**	**50**	**75**	**-**	**714**	**148**
Winter	**188**	**1,652**	**239**	**-**	**-**	**-**	**30**	**57**	**-**	**714**	**114**

Figure N-133: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: CAR Cap on WA CCCT Plants

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	26	-
2019	-	-	-	-	-	-	-	-	-	51	-
2020	-	-	-	-	-	-	-	-	-	98	-
2021	-	-	-	-	-	-	-	-	-	95	-
2022	-	413	-	-	-	50	-	-	-	41	-
2023	-	-	-	-	-	222	-	-	-	36	5
2024	-	-	-	-	-	93	-	-	-	34	10
2025	-	-	-	-	-	-	-	-	-	33	14
2026	-	413	-	-	-	-	-	-	-	32	14
2027	-	-	-	-	-	-	-	-	-	31	5
2028	-	-	-	-	-	-	-	-	-	26	-
2029	-	-	-	-	-	-	-	-	-	19	0
2030	-	-	-	-	-	25	-	25	-	18	0
2031	-	413	-	-	-	-	-	-	-	19	0
2032	-	-	-	-	-	25	-	25	-	19	0
2033	-	413	-	-	-	65	-	-	-	18	0
2034	-	-	-	-	-	-	-	-	-	16	0
2035	-	-	-	-	-	-	-	-	-	15	0
2036	-	413	-	-	-	-	-	-	-	15	1
2037	-	-	-	-	-	25	-	-	-	15	0
Total	**188**	**2,065**	**-**	**-**	**-**	**505**	**-**	**50**	**-**	**658**	**51**
Winter	**188**	**2,065**	**-**	**-**	**-**	**-**	**-**	**38**	**-**	**658**	**39**

Figure N-134: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Additional Conservation – Incremental (Bundle 5)

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	36	11
2019	-	-	-	-	-	-	-	-	-	67	21
2020	-	-	-	-	-	-	-	-	-	114	30
2021	-	-	-	-	-	25	-	-	-	110	29
2022	-	-	-	-	-	-	-	-	-	56	9
2023	-	-	-	-	-	221	-	-	-	51	4
2024	-	-	-	-	-	25	-	-	-	48	10
2025	-	-	-	-	-	-	25	50	28	47	13
2026	-	413	-	-	-	-	-	-	-	46	15
2027	-	-	-	-	-	-	-	-	-	45	6
2028	-	-	-	-	-	35	-	-	-	34	-
2029	-	-	-	-	-	-	-	-	37	23	0
2030	-	413	-	-	-	-	-	-	-	22	2
2031	-	-	-	-	-	30	-	-	-	22	1
2032	-	413	-	-	-	-	-	-	-	22	1
2033	-	-	-	-	-	69	-	-	-	20	1
2034	-	-	-	-	-	-	-	-	-	18	1
2035	-	-	-	-	-	-	-	-	-	17	1
2036	-	413	-	-	-	-	-	-	-	16	2
2037	-	-	60	-	-	25	-	-	-	16	1
Total	**188**	**1,652**	**60**	**-**	**-**	**430**	**25**	**50**	**65**	**830**	**157**
Winter	**188**	**1,652**	**60**	**-**	**-**	**-**	**15**	**38**	**63**	**830**	**121**

Figure N-135: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Additional Conservation – All (Bundle 10)

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	93	-
2019	-	-	-	-	-	-	-	-	-	140	-
2020	-	-	-	-	-	-	-	-	-	190	-
2021	-	-	-	-	-	-	-	-	-	190	-
2022	-	-	-	-	-	-	-	-	-	139	-
2023	-	-	-	-	-	72	-	-	-	134	4
2024	-	-	-	-	-	-	-	-	-	121	8
2025	-	-	-	-	-	-	-	-	-	122	12
2026	-	-	-	-	-	-	-	-	-	113	12
2027	-	-	-	-	-	-	-	-	-	109	4
2028	-	-	-	-	-	-	-	-	-	83	-
2029	-	-	-	-	-	-	-	-	-	61	(0)
2030	-	-	-	-	-	-	-	-	-	55	0
2031	-	413	-	-	-	-	-	-	-	49	0
2032	-	-	-	-	-	-	-	-	-	52	0
2033	-	-	-	-	-	-	-	-	-	44	0
2034	-	-	-	-	-	-	-	-	-	35	0
2035	-	-	-	-	-	-	-	-	-	32	0
2036	-	413	-	-	-	-	-	-	-	30	0
2037	-	-	-	-	-	25	-	50	-	28	0
Total	**188**	**826**	**-**	**-**	**-**	**97**	**-**	**50**	**-**	**1,820**	**42**
Winter	**188**	**826**	**-**	**-**	**-**	**-**	**-**	**38**	**-**	**1,820**	**32**

Figure N-136: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Early Retirement of Colstrip 3 & 4

Annual Builds (MW)	Transmission Redirect	CCCT	Frame Peaker	WA Wind	MT Wind	Solar	Li-Ion 2-hr Battery	Flow 4-hr Battery	Pumped Storage Hydro	DSR	Demand Response
2018	188	-	-	-	-	-	-	-	-	38	8
2019	-	-	-	-	-	-	-	-	-	73	16
2020	-	-	-	-	-	-	-	-	-	126	23
2021	-	-	-	-	-	-	-	-	-	121	22
2022	-	-	-	-	-	40	-	-	-	52	7
2023	-	-	-	-	-	225	-	25	-	44	3
2024	-	-	-	-	-	29	25	25	-	46	7
2025	-	-	239	-	-	-	-	-	-	47	10
2026	-	826	-	-	-	-	-	-	-	47	11
2027	-	-	-	-	-	-	-	-	-	40	4
2028	-	-	-	-	-	60	-	-	-	28	-
2029	-	-	-	-	-	-	-	-	-	20	-
2030	-	-	-	-	-	-	-	25	-	21	1
2031	-	413	-	-	-	32	-	-	-	21	1
2032	-	-	-	-	-	-	-	-	-	21	1
2033	-	413	-	-	-	72	-	-	-	20	1
2034	-	-	-	-	-	-	-	-	-	18	1
2035	-	-	-	-	-	-	-	-	-	17	1
2036	-	-	-	-	-	-	-	-	-	17	1
2037	-	-	-	-	-	26	-	-	-	16	1
Total	**188**	**1,652**	**239**	**-**	**-**	**484**	**25**	**75**	**-**	**834**	**121**
Winter	**188**	**1,652**	**239**	**-**	**-**	**-**	**15**	**57**	**-**	**834**	**121**

Change in WECC Emissions by Resource Type

Figure N-137: Change in WECC Emissions by Resource Type

Carbon Abatement: 50% Washington RPS

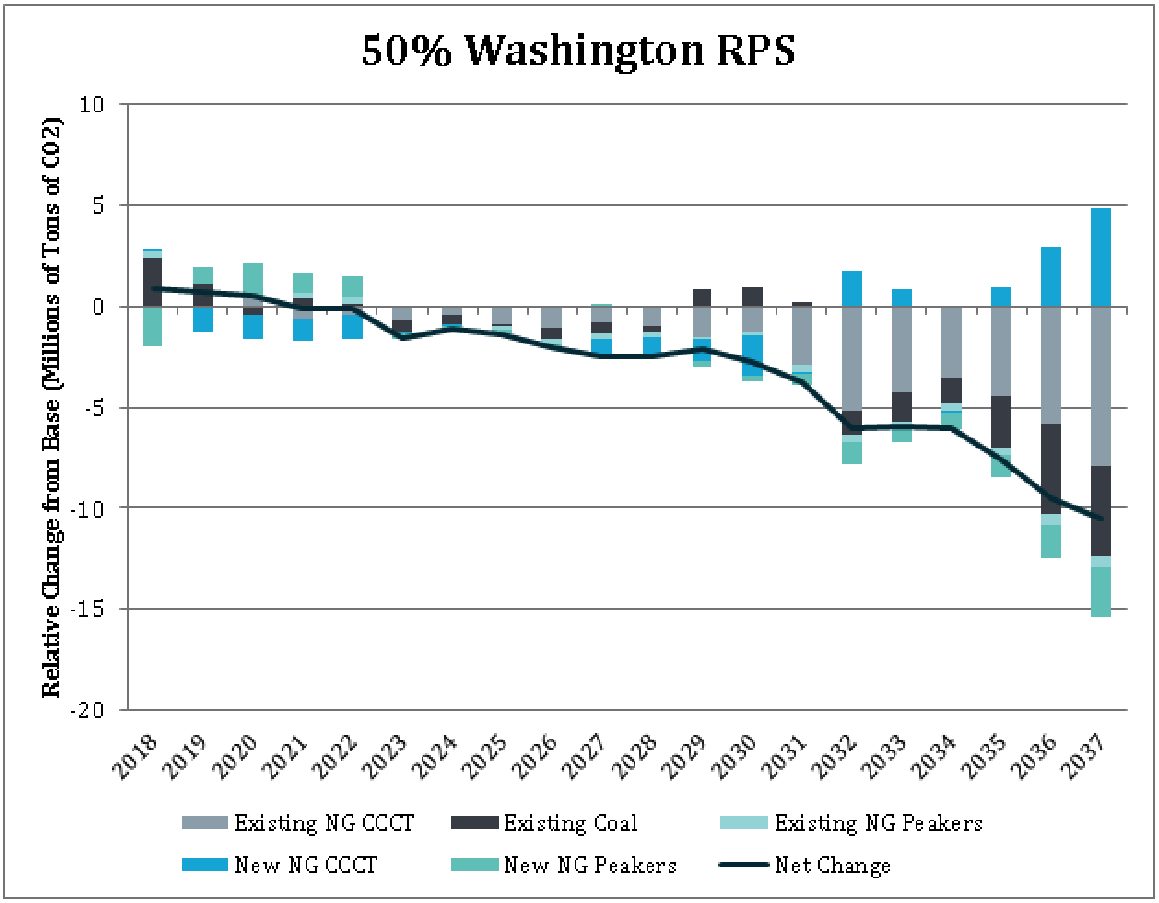


Figure N-138: Change in WECC Emissions by Resource Type

Carbon Abatement: Add 300 MW Solar

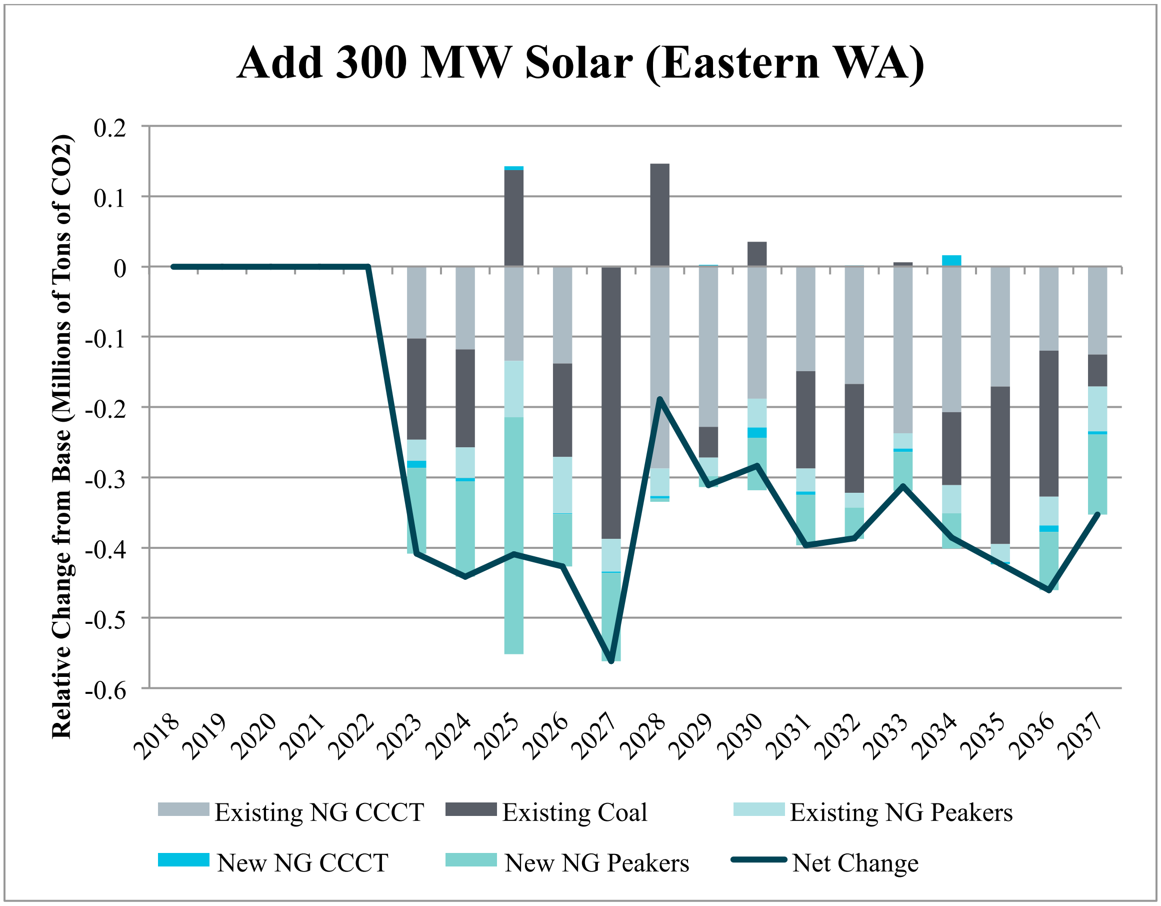


Figure N-139: Change in WECC Emissions by Resource Type

Carbon Abatement: Add 300 MW Wind

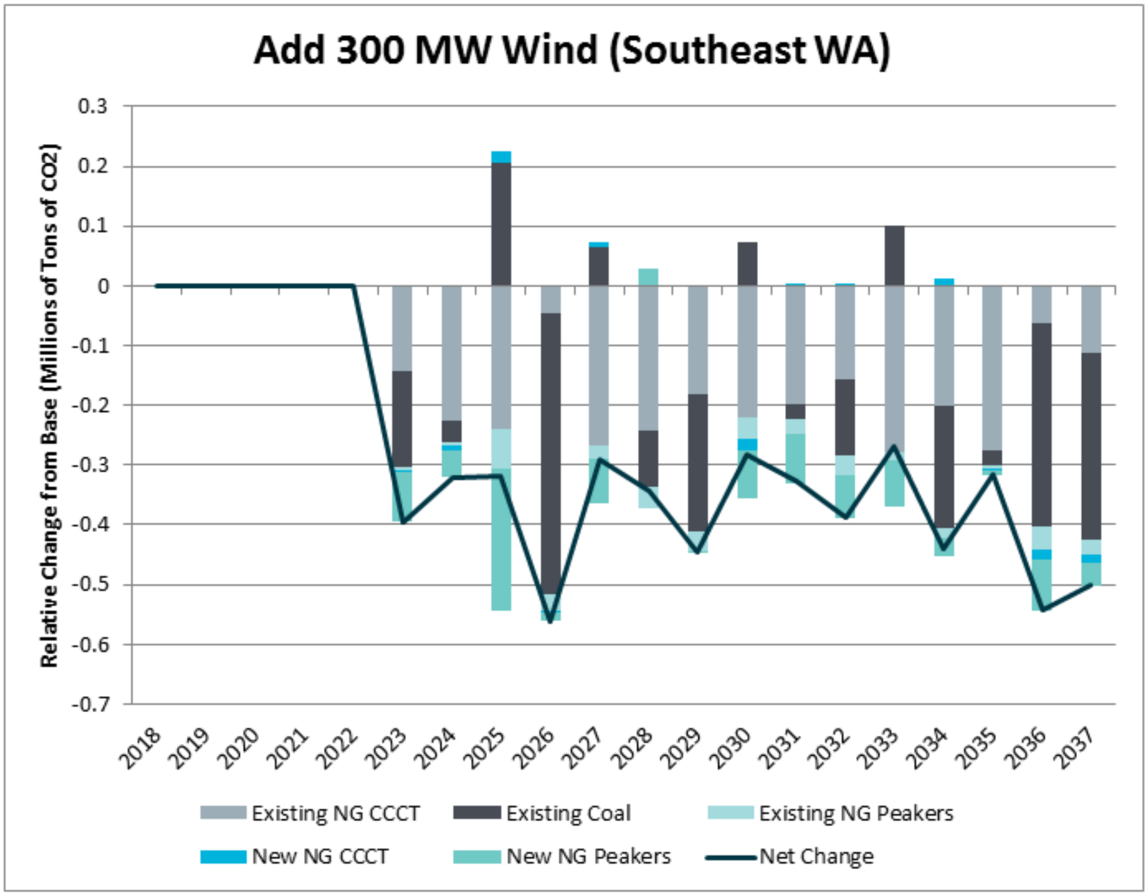


Figure N-140: Change in WECC Emissions by Resource Type

Carbon Abatement: CAR Cap on WA CCCT

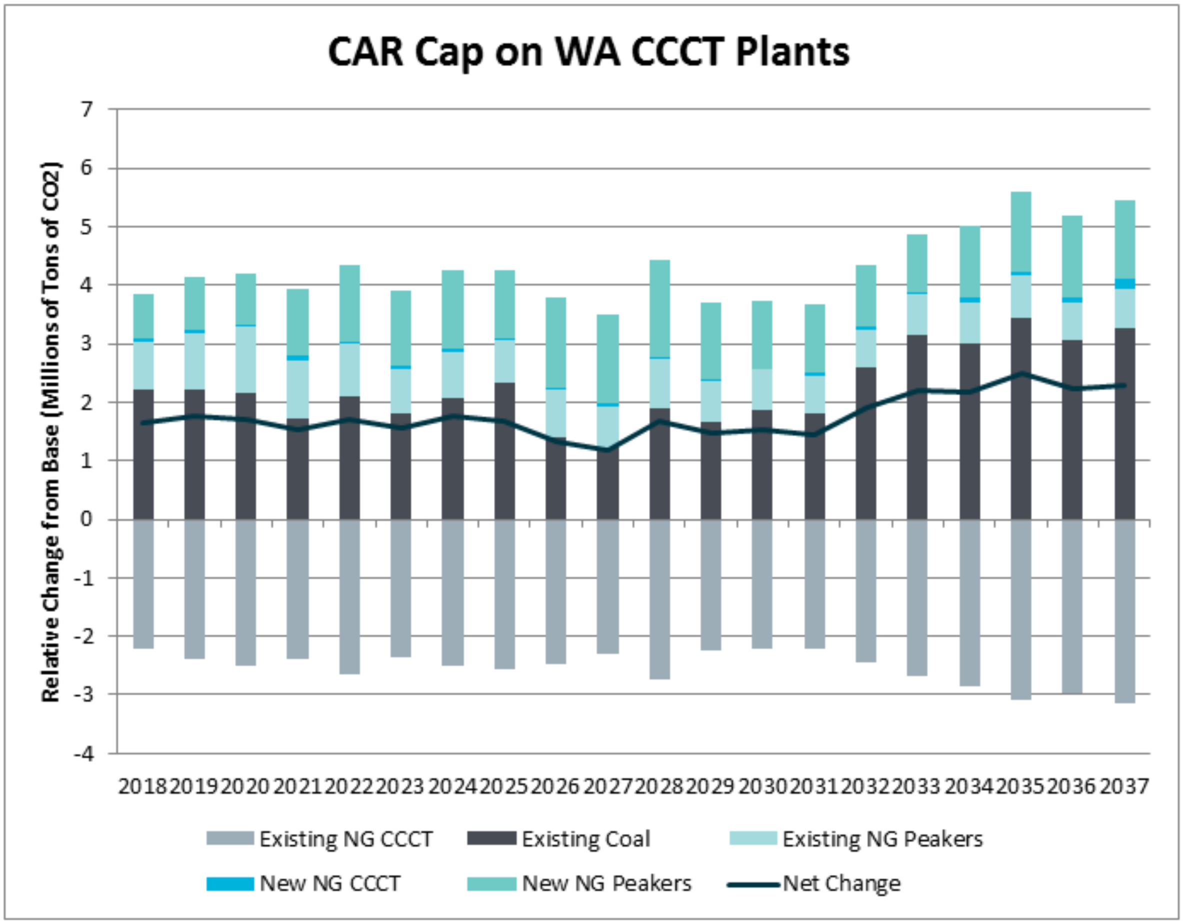


Figure N-141: Change in WECC Emissions by Resource Type

Carbon Abatement: Additional Conservation - Incremental

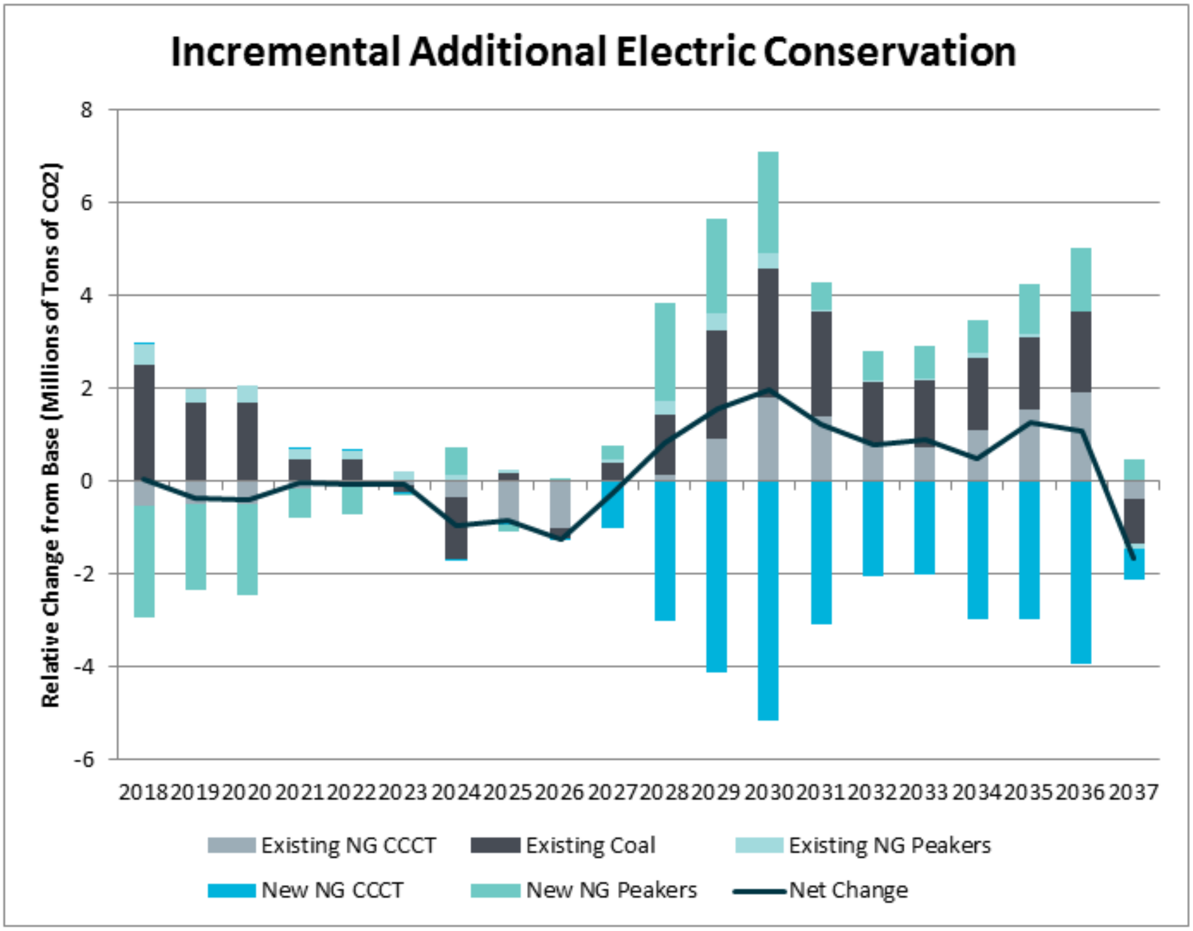


Figure N-142: Change in WECC Emissions by Resource Type

Carbon Abatement: Additional Conservation – All

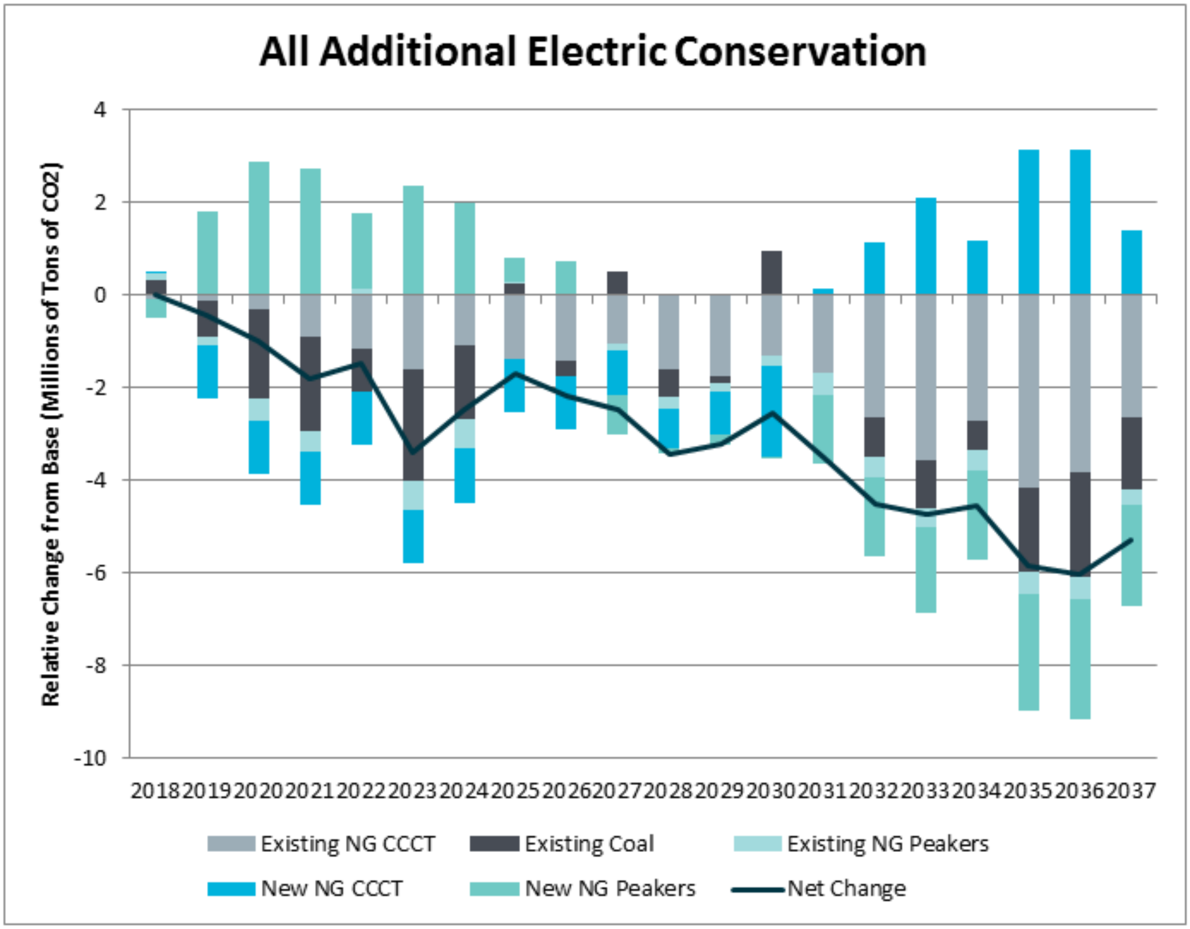
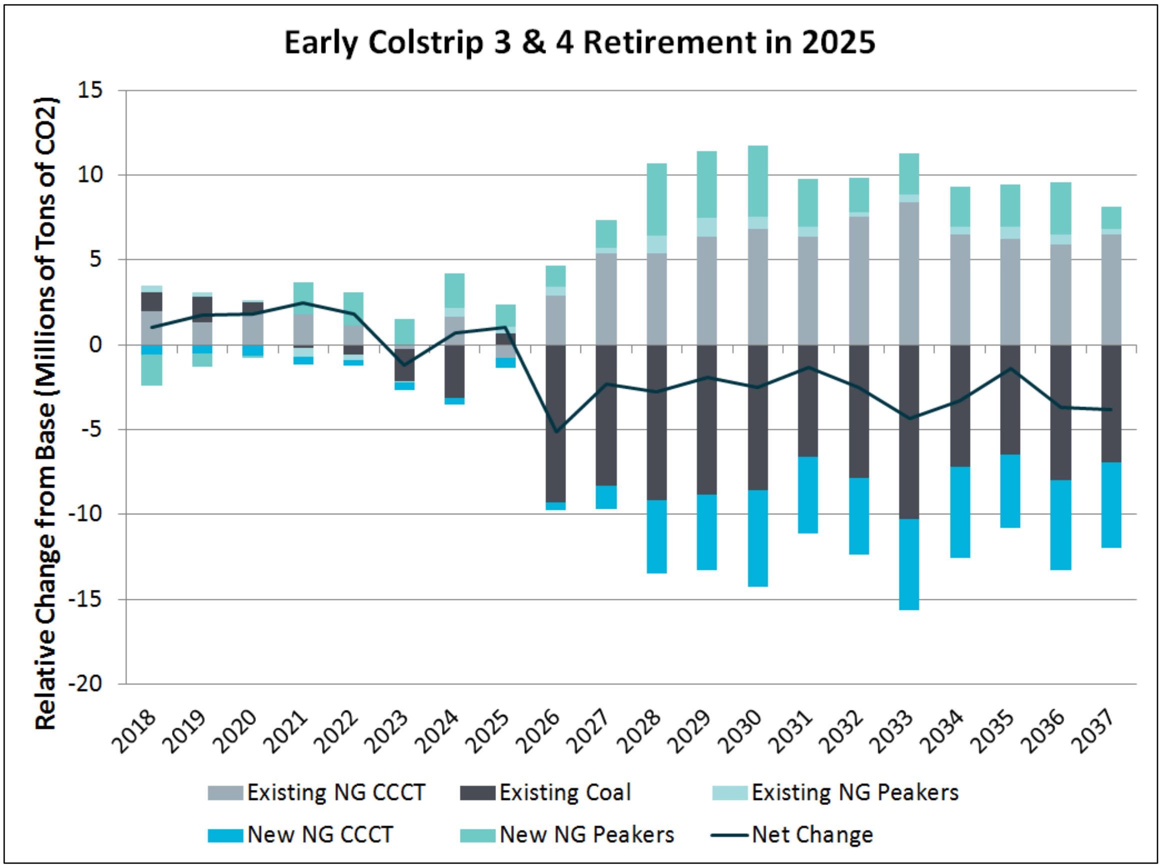


Figure N-143: Change in WECC Emissions by Resource Type

Carbon Abatement: Early Retirement of Colstrip 3 & 4



Gas Portfolio CO_2 Emissions – Carbon Abatement

Figure N-144: Total Portfolio CO_2 Emissions

Emission PSE Portfolio – Carbon Abatement Gas (Millions Tons)

	Base No CO2	Base No CO2 + 2 more DSR	Base No CO2 + all DSR
2018	5.63	5.63	5.62
2019	5.68	5.68	5.65
2020	5.75	5.75	5.70
2021	5.77	5.77	5.70
2022	5.79	5.79	5.70
2023	5.85	5.85	5.74
2024	5.93	5.92	5.79
2025	5.94	5.93	5.78
2026	5.98	5.97	5.80
2027	6.01	6.00	5.81
2028	6.08	6.07	5.87
2029	6.13	6.12	5.90
2030	6.20	6.19	5.95
2031	6.27	6.26	6.01
2032	6.38	6.36	6.10
2033	6.42	6.41	6.14
2034	6.50	6.48	6.20
2035	6.58	6.57	6.28
2036	6.70	6.68	6.38
2037	6.76	6.74	6.43

9. INCREMENTAL COST OF RENEWABLE RESOURCES

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 was 3 percent of retail electric load, and for 2016, it was 9 percent. 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 law states it this way: "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 resources that do not qualify as eligible renewable resources."

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. There may be other approaches to calculating these costs – such as using variable costs from different kinds of thermal plants instead of market. However, PSE's approach is most reasonable because it most closely reflects how customers will experience costs; i.e., PSE would not dispatch a peaker or CCCT with the ramping up and down of a wind farm without regard to whether the unit is being economically dispatched. For example, a peaker will not be economically dispatched often at all, so capacity from the thermal plant and energy from market is the closest match to actual incremental costs – and that is the point of this provision in the law – a to ensure customers don't pay too much. 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).

"Eligible Renewable Resources"

Figure N-145: Resources that Meet RCW 19.285 Definition of Eligible Renewable Resources

	Nameplate (MW)	Annual Energy (aMW)	Commercial Online Date	Market Price/ Peaker Assumptions	Capacity Credit Assumption
Hopkins Ridge	149.4	53.3	Dec-05	2004 RFP	20%
Wild Horse	228.6	73.4	Dec-06	2006 RFP	17.20%
Klondike III	50	18	Dec-07	2006 RFP	15.60%
Hopkins Infill	7.2	2.4	Dec-07	2007 IRP	20%
Wild Horse Expansion	44	10.5	Dec-09	2007 IRP	15%
Lower Snake River I	342.7	102.5	Apr-12	2010 Trends	5%
Snoqualmie Upgrades	6.1	3.9	Mar-13	2009 Trends	95%
Lower Baker Upgrades	30	12.5	May-13	2011 IRP Base	95%
Generic Solar 2022	266	70.8	Jan-22	2017 IRP Base	0%
Generic Solar 2024	112	29.8	Jan-24	2017 IRP Base	0%
Generic Solar 2032	25	6.7	Jan-32	2017 IRP Base	0%
Generic Solar 2033	59	15.7	Jan-33	2017 IRP Base	0%
Generic Solar 2037	25	6.6	Jan-37	2017 IRP Base	0%

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 the 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.

Cost of Renewable Resource

Levelized cost of the renewable resource is more direct. It is based on the proforma 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.

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 MW

1. Calculate Wild Horse revenue requirement.

Figure N-146 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 N-146: 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**				

2. Calculate revenue requirement for equivalent non-renewable: Peaker capacity.

Capacity = 39 MW

Capital Cost of Capacity: $462/KW

Figure N-147: 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.

Figure N-148:: Calculation of Energy Revenue Requirement

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 = $845
($Millions)						
Cost of Market				36	...	41
Imputed Debt				1	...	0
Total Revenue Requirement			285	37	...	41

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 N-149: 20-yr Incremental Cost of Wild Horse

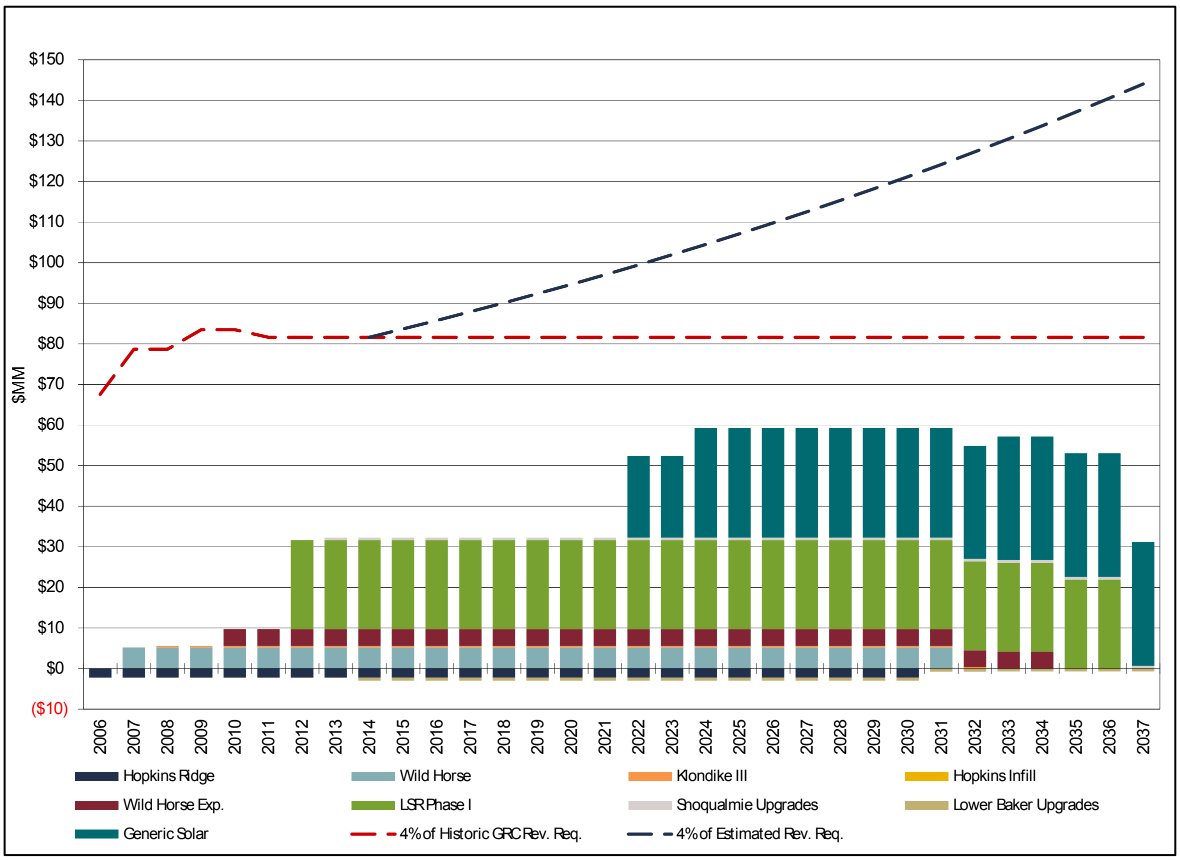
($ Millions)	20-yr NPV
Wild Horse	375
Peaker	34
Market	285
20-yr Incremental Cost of Wild Horse	**56**

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 per year using the 7.01 percent discount rate.

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 N-150 resents 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. A 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 N-150: Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4% of 2011 GRC Revenue Requirement + 2014 PCORC Adjustment



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 company's current revenue requirement.