6

2017 PSE Integrated Resource Plan

Electric Analysis

This chapter presents the results of the electric analysis.

Contents

(continued next page)

1. ANALYSIS OVERVIEW

The electric analysis in the 2017 IRP followed the seven-step process outlined below. Steps 1, 3, 4 and 5 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Analyze Resource Need

Three types of resource need are identified: peak capacity need, renewable need and energy need.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 4 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 5 presents the 2017 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Deterministic Analysis of Scenarios and Sensitivities

Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.

- All scenarios and sensitivities were analyzed using deterministic optimization analysis.

4. Stochastic Risk Analysis

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how the different portfolios developed in the deterministic analysis perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO_2 prices.

- PSE analyzed eight portfolios against 250 combinations of variables in the stochastic risk analysis.

5. Analyze Results

Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions about the resource plan forecast.

- Results of the analysis are presented in this chapter and in Appendix N.

6. Make Decisions

Chapter 2 describes the reasoning behind the strategy chosen for this resource plan forecast.

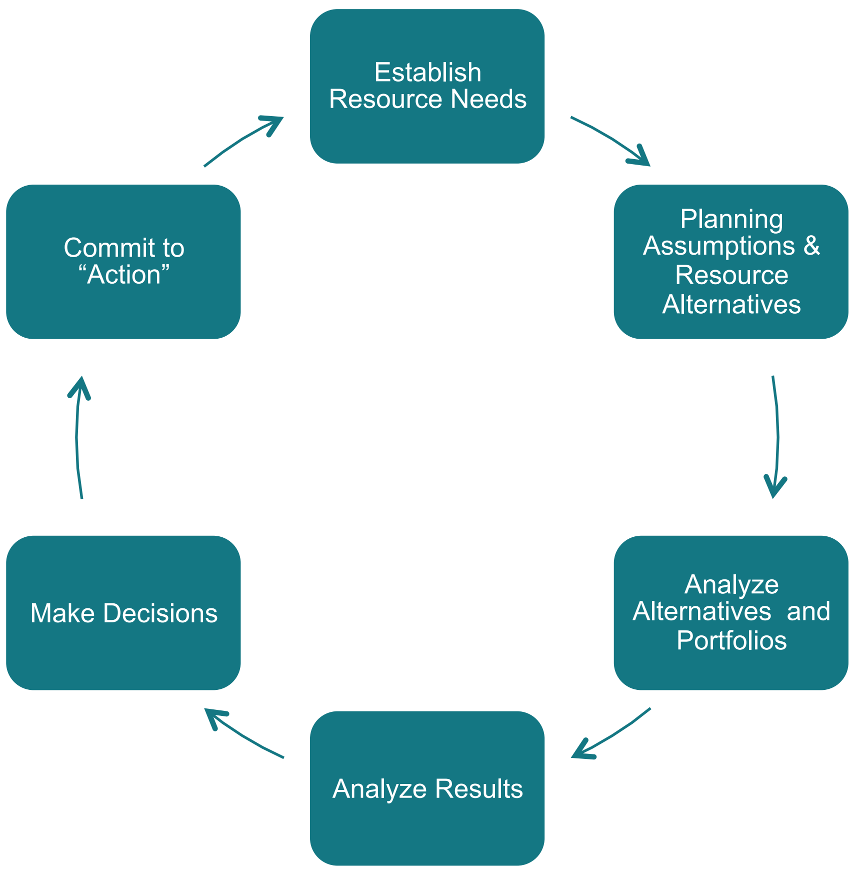
7. Commit to Action

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the Action Plan; this is "the plan" that PSE will execute against.

- The Action Plan is presented in the Executive Summary, Chapter 1.

Figure 6-1 illustrates this process.

Figure 6-1: 2017 IRP Process



2. RESOURCE NEED

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

Components of Physical (Peak) Need

Physical need refers to the resources required to ensure reliable operation of the system. It is an operational requirement that includes three components: customer demand, planning margins and operating reserves. The word "load" – as in "PSE must meet load obligations" – specifically refers to customer demand plus planning margins plus operating reserve obligations. The planning margin and operating reserves are amounts over and above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events such as variations in temperature, hydro and wind generation; equipment failure; or transmission interruption with minimal interruption of service.

When we compare physical need with the peak capacity value of existing resources, the resulting gap identifies resource need. Each of these four components – customer demand, planning margins, operating reserves and existing resources – is reviewed below.

Customer Demand

PSE develops a range of demand forecasts for the 20-year IRP planning horizon using national, regional and local economic and population data.[1] Chapter 5 presents the 2017 IRP Base, Low and High Demand Forecasts, and Appendix E delivers a detailed discussion of the econometric models used to develop them.

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

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

Planning Margin

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability (LOLP). 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.[2] Appendix N provides a detailed discussion of how PSE's Resource Adequacy Model is used to develop the planning margin.

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. Both GENESYS and RAM use 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 for PSE to achieve a 5 percent LOLP in the study year October 2020 – September 2021.[3]

2 / See http://www.nwcouncil.org/library/2008/2008-07.htm
3 / 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.

STEP 2: DETERMINE PLANNING MARGIN. Figure 6-2 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 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 6-2: 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 6-3, below, for peak need calculation. This is the reverse of Figure 6-2, above. In Figure 6-2, 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 6-3: 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 (ELCC). ELCC refers to the peak capacity contribution of a resource relative to that of a gas-fired peaking plant. It is calculated as the change in capacity of a generic natural gas peaking plant that results from adding a different resource with any given energy production characteristics to the system while keeping the target reliability metric constant. In this way, we can identify the capacity contribution of different resources such as wind, solar, wholesale market purchases and other energy limited resources such as batteries, demand response programs and backup fuel for thermal resources. (For a more detailed explanation of ELCC, see Appendix N, Electric Analysis.) Figure 5-4 below shows the estimated ELCC for the resources listed.

Figure 6-4: ELCC Estimates

Resource	Nameplate (MW)	Peak Capacity Credit Based on 5% LOLP
Generic gas-fired generation	239 MW	100%
Existing Wind	823	11%
Skookumchuck (DNV GL data[4])	131	40%
Generic Montana Wind (DNV-GL data)	100	49%
Generic Washington Wind (DNV-GL data)	100	16%
Generic Offshore Washington Wind (DNV-GL data)	100	51%
Market Reliance	1,580	99%
Generic Washington Solar	50	0%

Resource	Nameplate (MW)	Peak Capacity Credit Based on EUE at 5% LOLP [1]
Batteries		
Lithium-ion, 2hr, 25 MW max per hour	25	60%
Lithium-ion, 4hr, 25 MW max per hour	25	88%
Flow Battery, 4hr, 25 MW max per hour	25	76%
Demand Response		
3hr duration, called every other 6 hours[2]	100	77%

NOTE
1. Since batteries and demand response are energy-limited resources, using the loss of load probability metric does not capture the frequency, magnitude and duration of outrages. For these resources, PSE uses expected unserved energy (EUE) to appropriately capture the risks associated with these resources.
2. Peak capacity credit of for demand response is applicable for incentive-based demand response such as direct load control (DLC) and third-party curtailment. In the IRP, this number was applied to both incentive-based and price-based programs.

4 / PSE contracted with DNV GL for sets of stochastic wind outputs from these locations, which PSE used as an input to its ELCC analysis. DNV GL did not calculate the peak capacity credits, but provided PSE with inputs to preform that analysis. Please refer to Appendix M for the DNV GL study.

Although a generic wind project could be located in many parts of the Northwest,[5] a southeast Washington wind location was chosen as the generic wind for this IRP. Good historical wind data exists for the area, PSE already owns development rights at the Lower Snake River site, and transmission to the grid already exists in this location. Comparison of improvements in the ELCC for other wind sites must account for the incremental transmission costs required to connect the site to the regional grid.

Operating Reserves

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

CONTINGENCY RESERVES. In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event.

The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources (hydro, wind and thermal) plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA).

BALANCING AND REGULATING RESERVES. Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves must be resources with the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.[6]

For PSE, the amount of reserves needed for the December peak is 128 MW. This is calculated as the difference between the day ahead schedule and the actuals. Regulation looks at the 5-minute

5 / PSE examined the incremental capacity equivalent of a central Washington wind project in the 2011 IRP.
6 / System flexibility needs are discussed in more detail in Appendix H, Operational Flexibility.

changes in generation and balancing looks at the 10-minute changes in generation. A full description of how this number was calculated can be found in Appendix H, Operational Flexibility.

Existing Resources

Figure 6-5 summarizes the winter peak capacity values for PSE's existing supply-side resources.

Figure 6-5: Existing Supply-side Resources
Nameplate Capacity and Winter Peak Capacity for December 2018

Type of Generation	Nameplate Capacity (MW)	Winter Peak Capacity (MW)
Hydro	973	853
Colstrip	677	658
Natural Gas	1,905[1]	2,061
Renewable Resources	956[2]	143
Contracts	614	695
Available Mid-C Transmission	2,331	1,722
Total Supply-side Resources	**7,456**	**6,132**

NOTES
1. The nameplate capacity for the natural gas units is based on the net maximum capacity that a unit can sustain over 60 minutes when not restricted to ambient conditions. Natural gas plants are more efficient in colder weather, so the winter peak capacity at 23 degrees F is higher than the nameplate capacity.
2. Includes Klondike III (50 MW) and Skookumchuck (131 MW) as a wind resource.

For the winter months of 2016, PSE is currently forecast to have a total of 1,881 MW of BPA transmission capacity and 450 MW of owned transmission capacity, for a total of 2,331 MW. A portion of the capacity, 609 MW, is allocated to long-term contracts and existing resources such as PSE's portion of the Mid-C hydro projects. This leaves 1,722 MW of capacity available for short-term market purchases. The specific allocation of that capacity as of December 2018 is listed below in Figure 6-6. The capacities and contract periods for the various BPA contracts are reported in Appendix D, and PSE's forecast Mid-C peak transmission capacities are included as part of the resource stack in Figure 6-7, Electric Peak Capacity Need.

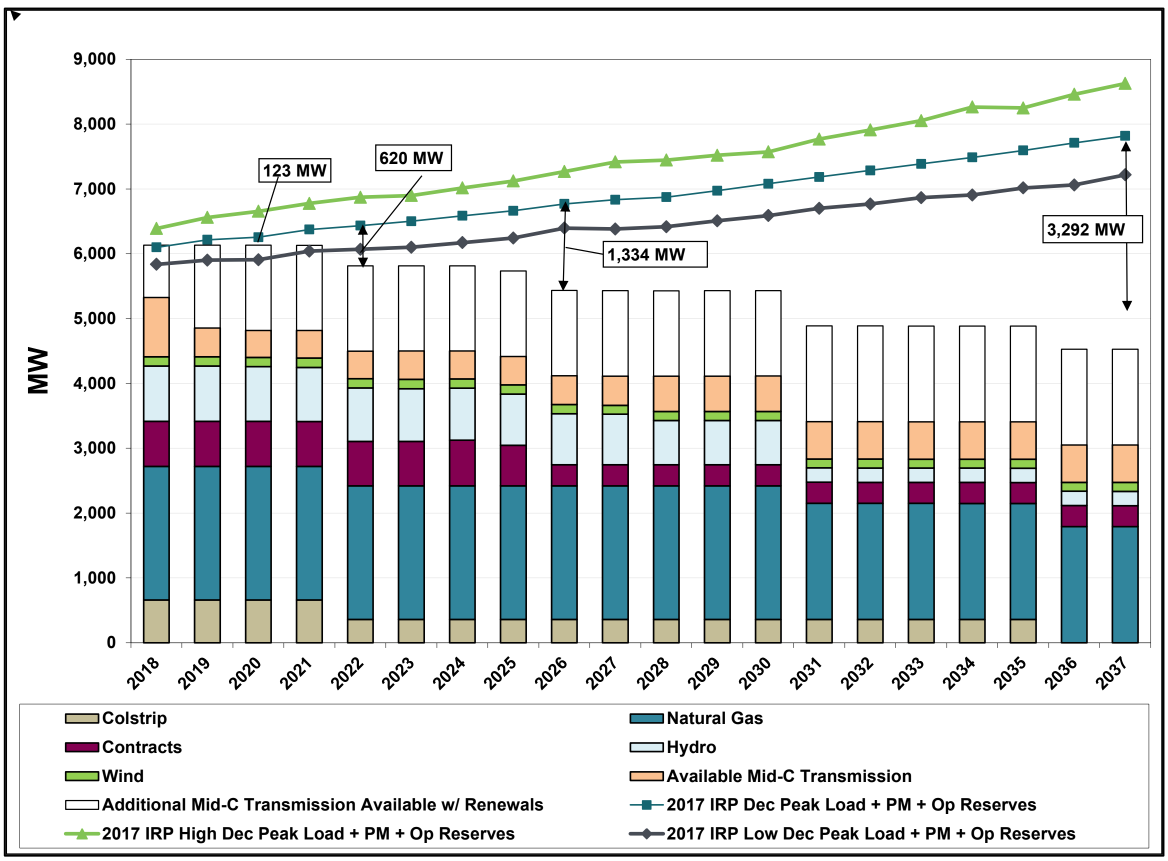
Figure 6-6: PSE Mid-C Transmission Capacity as of December 2016

	Winter Peak Capacity (MW)
Total Mid-C Transmission	2,331
Allocated to Long-term Resources & Contracts	(609)
Available for short-term wholesale market purchases	1,722

Peak Capacity Need

Figure 6-7 shows the physical reliability (peak) need for the three demand scenarios modeled in this IRP. Before any additional demand-side resources, peak capacity need in the Base Demand Forecast plus reserves is almost 620 MW by 2022 and over 3,200 MW by the end of the planning period. This picture differs from Figure 1-1 in Chapter 1, because it includes no demand-side resources past the study period's start date. One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan, and to accomplish this it is necessary to start with peak need forecasts that do not include forward projections of conservation savings.

Figure 6-7: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



NOTE: The physical characteristics of the electric grid are very complex, so for planning purposes we simplify physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model. The RAM analysis produces reliability metrics that allow us to assess physical resource adequacy risk; these include LOLP (loss of load probability), EUE (expected unserved energy) and LOLH (loss of load hours). We can simplify physical resource need in this way because PSE is much less hydro-dependent than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If PSE were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources or contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons.

Energy Need

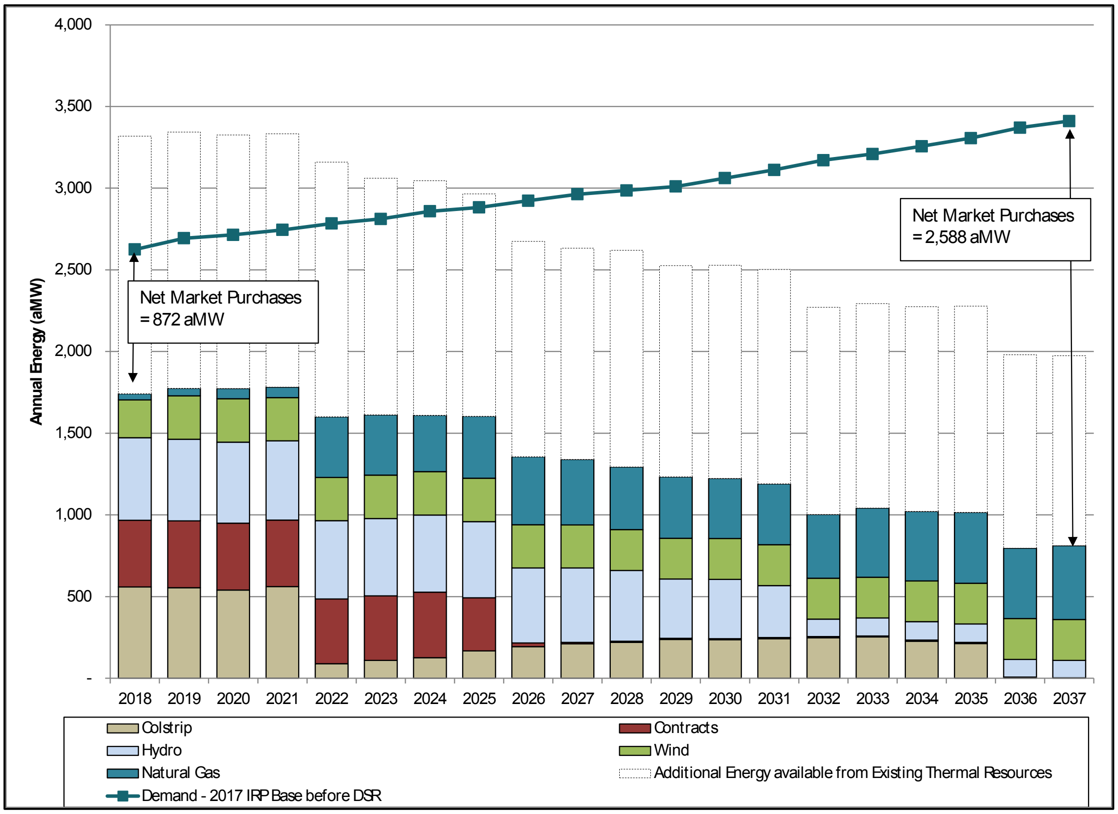
Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically.

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. In fact, PSE could generate significantly more energy than needed to meet our load on an average monthly or annual basis, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economical; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE's models will displace higher-cost market purchases and use the wind to meet the energy need.

Figure 6-8 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2017 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions. The white box at the top of the stack, "Additional Energy Available from Existing Thermal Resources," indicates the total energy available from PSE's thermal resources regardless of economic dispatch.

Figure 6-8: Annual Energy Position

Resource Economic Dispatch from Base Scenario



Renewable Need

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

Washington State RPS Targets
Renewable resources must comprise:
3 percent of supply-side resources by 2012
9 percent of supply-side resources by 2016
15 percent of supply-side resources by 2020

PSE has sufficient qualifying renewable resources to meet RPS requirements until 2022, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades.

MATURING RESOURCES. PSE continues to monitor emerging resources that may develop effective utility applications. This IRP incorporates renewable resources such as battery storage, distributed solar generation and utility-scale solar. The results of these analyses are discussed later in this chapter.

RENEWABLE RESOURCES INFLUENCE SUPPLY-SIDE RESOURCE DECISIONS. Adding intermittent resources to the portfolio increases the need for stand-by backup generation that can be turned on and off or adjusted up or down quickly. The amount of electricity supplied to the system by intermittent renewable resources drops off when the wind or sun ramp down, but customer need does not, therefore, as the amount of intermittent resources in the portfolio increases, so does the need for reliable backup generation.

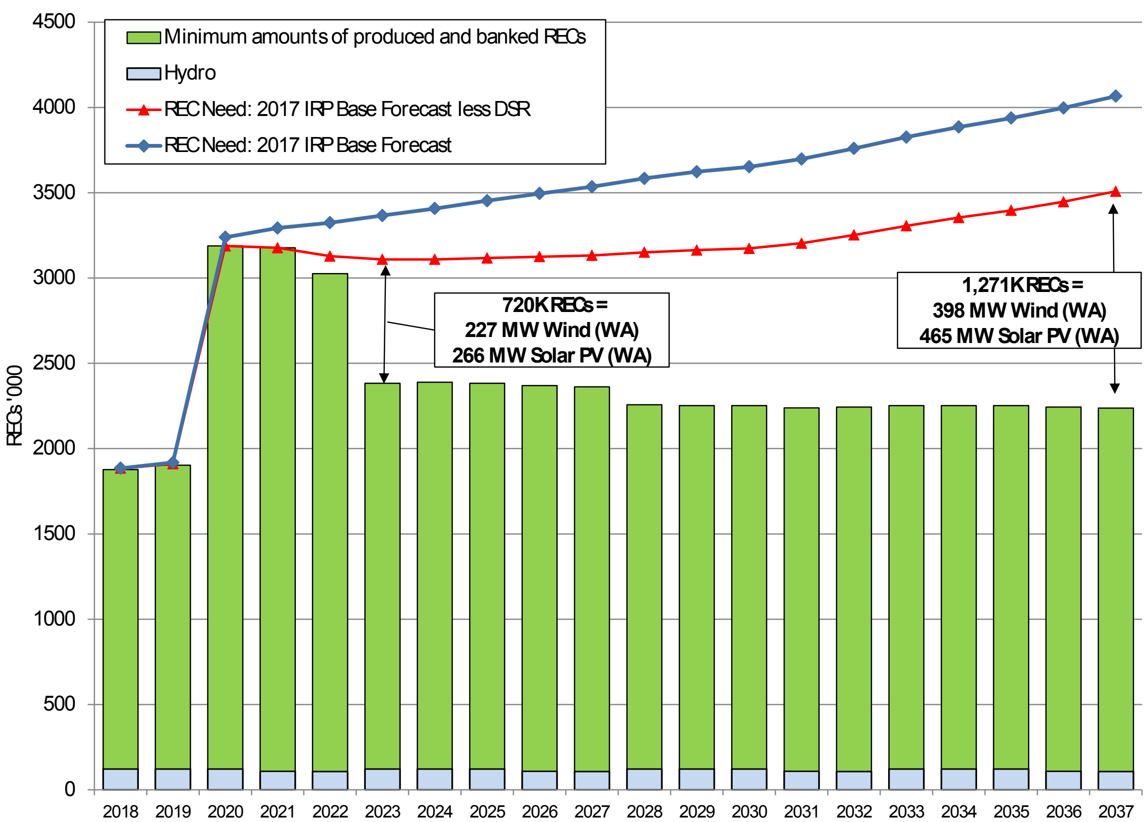
DEMAND-SIDE ACHIEVEMENTS AFFECT RENEWABLE AMOUNTS. Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, if MWh sales decrease, so does the amount of renewables we need. Achieving demand-side resources (DSR) targets has precisely this effect: DSR decreases sales volumes, which then decreases the amount of renewable resources needed.

REC Banking Provision

Washington's renewable portfolio standard allows for REC banking. Unused RECs can be banked forward one year or can be borrowed from one year in the future. In this IRP, PSE assumes that the company would employ a REC banking strategy that would push the need for additional RECs further into the future.

Figure 6-9 illustrates the need for renewable energy – wind or solar – after accounting for REC banking and the savings from demand-side resources that were found cost effective for the 2017 IRP.

Figure 6-9: REC Need Based on Achievement of All Cost-effective DSR



3. ASSUMPTIONS AND ALTERNATIVES

The scenarios, sensitivities and resource alternatives used in the electric analysis are summarized here for convenience.[7]

Scenarios and Sensitivities

Scenarios enable us to test how resource portfolio costs and risks respond to changes in economic conditions, environmental regulation, natural gas prices and energy policy. Sensitivities start with the Base Scenario assumptions and change one resource; this allows us to isolate the effect of an individual resource on the portfolio, so that we can consider how different combinations of resources would affect costs, cost risks and emissions.

7 / Chapter 4 presents the scenarios and sensitivities developed for this IRP analysis and discusses in detail the key assumptions used to create them, including customer demand, natural gas prices, possible carbon dioxide (CO_2) prices, resource costs (both demand-side and supply-side) and power prices. Appendix D presents a detailed discussion of existing electric resources and resource alternatives.

Figure 6-10: 2017 IRP Scenarios

	Scenario Name	Demand	Gas Price	CO_2 Price
1	**Base Scenario**	Mid	Mid	Mid
2	**Low Scenario**	Low	Low	Low
3	**High Scenario**	High	High	High
4	**High + Low Demand**	Low	High	High
5	**Base + Low Gas Price**	Mid	Low	Mid
6	**Base + High Gas Price**	Mid	High	Mid
7	**Base + Low Demand**	Low	Mid	Mid
8	**Base + High Demand**	High	Mid	Mid
9	**Base + No CO_2**	Mid	Mid	None
10	**Base + Low CO_2 w/ CPP**	Mid	Mid	Low + CPP
11	**Base + High CO_2**	Mid	Mid	High
12	**Base + Mid CAR only (electric only)**	Mid	Mid	Mid CAR only
13	**Base + CPP only (electric only)**	Mid	Mid	CPP only
14	**Base + All-thermal CO_2 (electric only)**	Mid	Mid	CO_2 price applied to all thermal resources in the WECC (baseload and peakers)

Fig 6-11: 2017 IRP Portfolio Sensitivities

	Sensitivities	Alternatives Analyzed
	ELECTRIC ANALYSIS	
A	**Colstrip** How do different retirement dates affect decisions about replacing Colstrip resources?	*Baseline – Retire Units 1 & 2 mid-2022, Units 3 & 4 remain in service into 2035.* 1. Retire Units 1 & 2 in 2018 2. Retire Units 3 & 4 in 2025 3. Retire Units 3 & 4 in 2030
B	**Thermal Retirement** Would it be cost effective to accelerate retirement of PSE's existing gas plants?	*Baseline – Optimal portfolio from the Base Scenario* Retire baseload gas plants early.
C	**No New Thermal Resources** What would it cost to fill all future need with resources that emit no carbon?	*Baseline – Fossil fuel generation is an option in the optimization model.* Renewable resources, energy storage and DSR are the only options for future resources.
D	**Stakeholder-requested Alternative Resource Costs** What if capital costs of resources are different than the base assumptions?	*Baseline – PSE cost estimate for generic supply-side resources* 1. Lower cost for recip peakers 2. Higher thermal capital costs 3. Lower wind and solar development costs 4. Apply more aggressive solar cost curve.
E	**Energy Storage** What is the cost difference between a portfolio with and without energy storage?	*Baseline – Batteries and pumped hydro included only if chosen economically.* 1. Add 50 MW battery in 2023 instead of economically chosen peaker. 2. Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker.
F	**Renewable Resources + Energy Storage** Does bundling renewable resources with energy storage change resource decisions?	*Baseline – Evaluate renewable resources and energy storage as individual resources in the analysis.* Bundle 50 MW battery + 200 MW solar
G	**Electric Vehicle Load** How much does electric vehicle charging affect the resource plan?	*Baseline – IRP Base Demand Forecast* Add the forecasted electric vehicle load.
	DEMAND-SIDE RESOURCES (CONSERVATION)	
H	**Demand-side Resources (DSR)** How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements* No DSR. All future needs met with supply-side resources.
I	**Extended DSR Potential** What if future DSR measures extend conservation periods through the second decade of the study period?	*Baseline – All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.* Assume future DSR measures will extend conservation benefits to the following 10-year period.
J	**Alternate Residential Conservation Discount Rate** How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation?	*Baseline: Assume the base discount rate.* Apply a societal discount rate to residential conservation savings to examine whether changing the discount rate for conservation impacts cost effectiveness of conservation.

	Sensitivities	Alternatives Analyzed
	ELECTRIC ANALYSIS	
	WIND RESOURCES	
K	**RPS-eligible Montana Wind [1]** What is the cost difference between a portfolio with "regular" Montana wind and RPS-eligible Montana wind?	*Baseline – Montana wind included only if chosen economically by the analysis.* 1. Add RPS-eligible Montana wind in 2023 instead of solar 2. Montana wind tipping point analysis to determine how close it is to being cost effective compared to other resources to being cost effective
L	**Offshore Wind Tipping Point Analysis** How much would costs of offshore wind need to decline before it appears to be a cost-effective resource?	*Baseline – Base Scenario portfolio* Offshore wind tipping point analysis to determine how close it is to being cost effective compared to other cost-effective resources.
M	**Hopkins Ridge Repowering [2]** Would repowering Hopkins Ridge for the tax incentives and bonus RECs be cost effective?	*Baseline – Hopkins Ridge repowering is not included in the portfolio.* Include Hopkins Ridge repowering in the portfolio to replace the current facility.

NOTES

1. Montana wind is not currently an RPS-eligible resource; however, PSE has asked BPA under what conditions it could be qualified as an RPS-eligible resource.

2. Repowering refers to refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. This sensitivity captures the impact of tax credit incentives and increased operating efficiency on cost.

Cost of Carbon Abatement Alternatives Analyzed

In this IRP, we examined several alternatives for reducing the greenhouse gas emissions. The purpose of this analysis was to estimate a supply curve for carbon abatement. The curve presents different carbon reduction alternatives and how much carbon reductions are achieved at various costs.

Figure 6-12: Carbon Abatement Alternatives Analyzed

COST OF CARBON ABATEMENT ALTERNATIVES ANALYZED		
PSE Portfolio Alternatives		
A	**Additional Wind**	Add 300 MW of wind beyond RPS requirements.
B	**Additional Utility-scale Solar**	Add 300 MW of utility-scale solar beyond RPS requirements.
C	**Additional Electric Conservation – Incremental**	Increase conservation by 2 bundles relative to least-cost portfolio.
D	**Additional Electric Conservation – All**	Increase conservation to incorporate the entire conservation potential assessment available at any cost.
E	**Cost-effective Electric DSR**	Impact of acquiring all cost-effective electric conservation.
Policy Alternatives		
F	**50% RPS in Washington**	Increase Washington RPS to 50% by 2040.
G	**CAR Cap on Washington CCCT plants**	Reduce the emissions of the CCCT plants in Washington to comply with the Washington Clean Air Rule CO2 emission baseline.
H	**Early Colstrip 3 & 4 Retirement**	Retire Colstrip 3 & 4 in 2025, rather than 2035, replacing it with the least-cost resources.
Gas Utility Alternatives		
I	**Additional Gas Conservation – Incremental**	Increase conservation by 2 bundles relative to least-cost portfolio.
J	**Additional Gas Conservation – All**	Increase conservation to incorporate the entire conservation potential assessment available at any cost.
K	**Cost-effective Gas DSR**	Impact of acquiring all cost-effective gas conservation.

Available Resource Alternatives

Existing resources and resource alternatives are described in detail in Appendix D.

Supply-side Resources

SHORT-TERM WHOLESALE MARKET PURCHASES. PSE relies on short-term wholesale market purchases for both peak capacity and energy. The short-term market purchases use the transmission contracts with Bonneville Power Administration to carry electricity from contracted wholesale market purchases to PSE's service territory. A more detailed discussion of the wholesale market is included in Appendix G.

BASELOAD GAS (CCCTS). F-type, 1x1 engines with wet cooling towers are assumed to generate 335 MW plus 50 MW of duct firing and be located in PSE's service territory.

PEAKERS (FRAME PEAKERS). F-type, wet-cooled turbines are assumed to generate 228 MW and located in PSE's service territory. They are modeled with 48 hours of oil backup and no firm pipeline capacity.

PEAKERS (AERO PEAKERS). The 2-turbine design with wet cooling is assumed to generate a total of 203 MW and to be located in PSE's service territory. They are modeled with 48 hours of oil backup and no firm pipeline capacity.

PEAKERS (RECIP PEAKERS). This 12-engine design (18.3 MW each) with wet cooling is assumed to generate a total of 220 MW and to be located in PSE's service territory. They are modeled with 48 hours of oil backup and no firm pipeline capacity. It is not clear if these units could meet emission thresholds for fine particulate matter in PSE's service territory, but they were modeled as being available to determine if follow-up on that issue is warranted.

WIND. Wind was modeled in southeast Washington, central Montana and offshore of the Washington coast. Southeast Washington wind is assumed to have a capacity factor of 30 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 46 percent. Offshore wind is assumed to have a capacity factor of 34 percent.

SOLAR. Utility-scale solar PV is assumed to be located in eastern Washington, use a tracking system, and have a capacity factor of 27 percent.

ENERGY STORAGE. Two energy storage technologies are modeled: batteries and pumped hydro. Two generic battery resources are modeled, lithium-ion batteries and flow batteries. Pumped hydro resources are generally large, on the order of 400 MW to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties.

Demand-side Resources

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in less energy being used to accomplish a given amount of work. These measures often focus on retrofitting programs and new construction codes and standards and include measures like appliance upgrades, building envelope upgrades, heating and cooling systems and lighting changes.

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

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators (like rooftop solar panels) located close to the source of the customer's load.

DISTRIBUTED EFFICIENCY (VOLTAGE REDUCTION AND PHASE BALANCING). Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing eliminates total current flow losses that can reduce energy loss.

GENERATION EFFICIENCY. Energy efficiency improvements at PSE generating plant facilities.

CODES AND STANDARDS. No-cost energy efficiency measures that work their way to the market via new efficiency standards. These originate from federal and state codes and standards.

4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.[8]

DETERMINISTIC PORTFOLIO OPTIMIZATION ANALYSIS. All scenarios and sensitivities are subjected to deterministic portfolio analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio – that is, the lowest cost mix of demand-side and supply-side resources that will meet need under the given set of static assumptions defined in the scenario or sensitivity. This stage helps us to learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

STOCHASTIC RISK ANALYSIS. In this stage of the resource plan analysis, we examine how different resource strategies respond to the types of risk that go hand-in-hand with future uncertainty. We deliberately vary the inputs that were static in the deterministic analysis to create simulations called "draws," and analyze the different portfolios. This allows us to learn how different strategies perform with regard to cost and risk across a wide range power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO_2 prices.

Deterministic Portfolio Optimization Analysis

Deterministic analysis helps to answer the question: How will different resource alternatives dispatch to market given the assumptions that define each of the scenarios and sensitivities? All of PSE's existing resources are modeled, plus all of the generic resource alternatives.

8 / To screen some resources, we also use simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

Four analytical tools are used during this stage of the analysis: AURORA, PLEXOS, the Portfolio Screening Model III (PSM III) and Frontline System's Risk Solver Platform.

The initial AURORA input price run produces:

1. **Annual Energy Estimates (MWh).** This is the sum of the total energy produced by each resource for the entire year.
2. **Annual Variable Cost Estimates ($000).** This includes fuel price plus variable pipeline charges, fuel use and taxes; variable operations and maintenance (O&M) cost; variable transmission cost; start-up costs; any emissions cost where applicable; and PPA costs.
3. **Annual Revenue ($000) Estimates.** This is the revenue that a resource produces when its excess energy production is sold into the market.
4. **CO_2 Emissions Estimates (tons).** For tracking total emissions in the portfolio.

PLEXOS is a production cost model similar to AURORA, but PLEXOS has the ability to do a sub-hourly dispatch of resources to meet all of PSE's load and reserve requirements. PLEXOS can perform a day-ahead simulation for unit commitment and a real-time simulation to re-dispatch resources to meet sub-hourly changes in demand and supply. PLEXOS is used to do a 5-minute dispatch for one (1) year to answer the following questions.

1. Does PSE have adequate capability to ramp resources up and down?
2. When new resources are added to the portfolio, what benefits do they have and do they help to reduce the operating cost of the portfolio?

A full discussion of the operational flexibility analysis can be found in Appendix H. The analysis resulted in a portfolio cost reduction by adding in different resources to the portfolio. The portfolio cost reduction was then divided by the size of the resource to get a $/kW-yr. For example, adding a 25 MW 4-hour flow battery had a benefit of $117/kW-yr. This benefit was input into the PSM model as a cost reduction for the resource. Figure 6-13 below shows the results of the operational flexibility analysis. The inputs to the PSM model are highlighted in green. Most of the benefits come from the day-ahead simulation. For thermal plants, the day-ahead benefits are captured in the AURORA portfolio analysis. For storage resources, the PLEXOS analysis captures and incorporates day-ahead and real-time benefits. The real-time vs. day-ahead difference isolates the benefits associated with flexibility.

Figure 6-13: Flexibility Benefit

IRP Resource	Annual Variable Cost Savings ($/kW-yr)	RT vs. DA Variable cost savings ($/kW-yr)
CCCT	($46)	-
Frame Peaker	($26)	($1)
Aero Peaker	($56)	($7)
Recip Peaker	($97)	($11)
2-hr Li-Ion Battery	($119)	($3)
4-hr Li-Ion Battery	($131)	($8)
4-hr Flow Battery	($117)	($2)
6-hr Flow Battery	($128)	($7)
Pumped Storage Hydro	($144)	($10)

The Portfolio Screening Model 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 System's Risk Solver Platform. This is an excel add-in that works with PSM III. Incremental cost includes: 1) the variable fuel cost and emissions for PSE's existing fleet, 2) the variable cost of fuel emissions and operations and maintenance for new resources, 3) the fixed depreciation and capital cost of investments in new resources, 4) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and 5) 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 III are:

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

A mathematical representation of PSM III can be found in Appendix N, Electric Analysis.

Stochastic Risk Analysis

With stochastic risk analysis, we test the robustness of different portfolios. In other words, we want to know how well the portfolio might perform under a range of 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 portfolio.

For this purpose, we take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 250 draws[9] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 regulations/prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed. For example, in the deterministic analysis for this IRP, the first renewable build under the Base Demand Forecast is in 2023 (Figure 6-12: Renewable need). When we perform the stochastic analysis with varying loads and wind generation, we find it is most likely that we will need the new renewable generation in 2022 to make sure we remain in compliance with RCW 19.285.

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

ANALYSIS TOOLS. A Monte Carlo approach is used to develop the stochastic inputs. Monte Carlo draws of inputs 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. Appendix N, Electric Analysis, includes a full description of how PSE developed the stochastic inputs.

5. KEY FINDINGS

The quantitative results produced by this extensive analytical and statistical evaluation led to the following key findings. These are summarized below and discussed in more detail in the following pages.

Scenarios

1. **PORTFOLIO BUILDS.** Portfolio additions across scenarios are very similar. The most common differences were whether battery storage or gas-fired generation is added to meet the first resource need, and which type of gas-fired generation was selected, peakers or baseload plants, in the latter part of the study period.

2. **EMISSIONS.** Emissions results vary across portfolios, with the economic dispatch of coal generation as the primary factor that differentiates results.

3. **COST OF CAPACITY.** Market conditions affect the net cost of peakers vs. baseload plants, not resource need. The value of flexibility and avoided transmission and distribution (T&D) costs affect the net cost of energy storage resources.

4. **BACKUP FUEL CAPACITY.** 48 hours of oil backup for the peakers is sufficient to meet winter demand.

5. **RENEWABLES.** RPS requirements and load forecasts drive renewable builds.

6. **WIND VS. SOLAR.** In this IRP, the cost of utility-scale solar dropped so much that it became more cost-effective than wind.

Sensitivities

A. **COLSTRIP.** Carbon regulation that adds dispatch cost will challenge the economics of Colstrip.

B. **THERMAL RETIREMENT.** The retirement of PSE's existing baseload gas plants in 2030 will be driven by how carbon tax regulation is implemented. In the case where the carbon tax is applied only to baseload plants and not to the alternative resources (frame peakers), there is a minimal benefit to shutting some of the baseload plants early. However, if the carbon tax is applied to both baseload and peaking plants, there is no longer a benefit to shutting the baseload plants early.

C. **NO NEW THERMAL RESOURCES.** If PSE added only renewable and energy storage resources to the portfolio in the future, the only resource large enough to replace the capacity is pumped hydro storage. Solar would be replaced by Montana wind, and frame peakers would be replaced by pumped hydro storage.

D. **STAKEHOLDER-REQUESTED ALTERNATIVE RESOURCE COSTS.** Changing the resource cost assumptions does not change the optimal portfolio, it just changes the cost of the portfolio.

E. **ENERGY STORAGE.** Batteries and pumped hydro storage are higher cost than traditional peaking plants, but energy storage can provide valuable flexibility. When its flexibility benefit is combined with avoided T&D costs, battery technology becomes a cost-competitive resource because it is more scalable than thermal resources.

F. **RENEWABLE RESOURCES + ENERGY STORAGE.** Combining renewable resources and energy storage results in tax credits that reduce cost, but the flexibility and T&D benefits that are gained from separating battery storage and renewable resources are greater than the cost reductions captured by combining them.

G. **ELECTRIC VEHICLE LOAD.** By 2035, electric vehicles could increase the peak demand by 230 MW, roughly equivalent to one frame peaker.

Demand-side Resources

H. **DEMAND-SIDE RESOURCES.** Energy efficiency and other demand-side resources are consistently cost effective and reduce risk. The level of cost-effective DSR varies little across scenarios.

I. **EXTENDED DSR POTENTIAL.** Extending the DSR potential to maintain the same level of achievement for the entire 20 years does not change the cost-effective amount of DSR chosen, but it does reduce the number of peakers built by 2037 by one peaker.

J. **ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE.** Changing the residential discount rate does not change the cost-effective amount of DSR chosen.

Wind Resources

K. **RPS-ELIGIBLE MONTANA WIND.** Based on current assumptions, Montana wind is not expected to be cost effective because of transmission cost. Given the solar cost curve assumptions, even if Montana wind is eligible for the Washington RPS, Washington solar is more cost effective than wind.

L. **OFFSHORE WIND TIPPING POINT ANALYSIS.** Offshore wind capital costs would have to drop by 73 percent to become a cost-competitive resource.

M. **HOPKINS RIDGE REPOWERING.** The analysis indicates that repowering Hopkins Ridge would add $40 million in costs. Based on these results, PSE would not move forward with the repowering of this wind facility.

Carbon Abatement Cost Curve

This analysis focuses on investigating overall WECC-wide impacts of different policies aimed at carbon abatement. This perspective allows the overall effectiveness of such policies to be examined. Policies that affect the economic operation of carbon-emitting resources in one part of the WECC can affect neighboring areas through adjusted interchange transactions. In other words, disincentivizing carbon emissions in one region can make imports from regions without carbon abatement policies more attractive.

6. SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all scenarios look very much alike since resource alternatives are so limited. Small variations occurred due to load variations in the high and low load forecasts, but the similarities are striking. The main difference was the type of gas-fired generation chosen. Baseload gas plants were selected as lower cost in some scenarios, while frame peakers were selected as lower cost in others. Also, in the High and Base + High Gas Scenarios, solar was cheaper than market due to such high gas and carbon prices, so in these scenarios, it was necessary to constrain solar to 500 MW. If solar did become cheaper than market, independent power producers would rush to build resources, driving up costs in many segments of the supply chain and causing solar costs to go up – a key assumption that was not reflected in our modeling. Additionally, as PSE's resources could greatly exceed load, PSE would have to adopt an energy planning standard to ensure the company operates as a utility rather than a wholesale power marketer. That is, that we add resources to meet the needs of customers, rather than taking a speculative position in the energy market. Figure 6-14 summarizes resource additions and net present value of portfolio costs across all 14 scenarios.

Figure 6-14: Relative Optimal Portfolio Builds and Costs by Scenario
(Cumulative nameplate capacity for each resource addition, in MW by 2037)
Dollars in billions, NPV including end effects

		NPV	DR	DSR	Trans. Redirect	CCCT	Peaker	Solar	MT Wind for RPS	Energy Storage
1	Base	$11.98	58	714	188	-	1,975	486	-	50
2	Low	$8.61	67	658	188	413	1,255	369	-	50
3	High	$15.40	148	728	188	-	2,875	500	300	50
4	High + Low Demand	$11.77	67	714	188	-	1,575	500	-	91
5	Base + Low Gas Price	$10.77	67	658	188	-	1,982	504	-	108
6	Base + High Gas Price	$13.27	157	714	188	-	1,735	500	300	76
7	Base + Low Demand	$10.70	58	714	188	-	1,575	351	-	102
8	Base + High Demand	$13.75	157	714	188	-	3,003	351	-	75
9	Base + No CO2	$10.45	148	714	188	1,652	257	484	-	100
10	Base + Low CO2 w/ CPP	$11.93	58	714	188	-	1,975	490	-	50
11	Base + High CO2	$11.98	58	714	188	-	1,975	490	-	50
12	Base + Mid CAR only (electric only)	$10.73	157	714	188	-	1,859	486	-	91
13	Base + CPP only (electric only)	$11.87	58	714	188	-	1,975	486	-	50
14	Base + All-thermal CO2 (electric only)	$12.66	157	714	188	826	1,026	486	-	100

Summary of Deterministic Optimization Analysis

Figure 6-15 below displays the megawatt additions for the deterministic analysis optimal portfolios for all scenarios in 2023, 2027 and 2037. No new resources are added until 2022. See Appendix N, Electric Analysis, for more detailed information.

Figure 6-15: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)

Scenarios 1-9

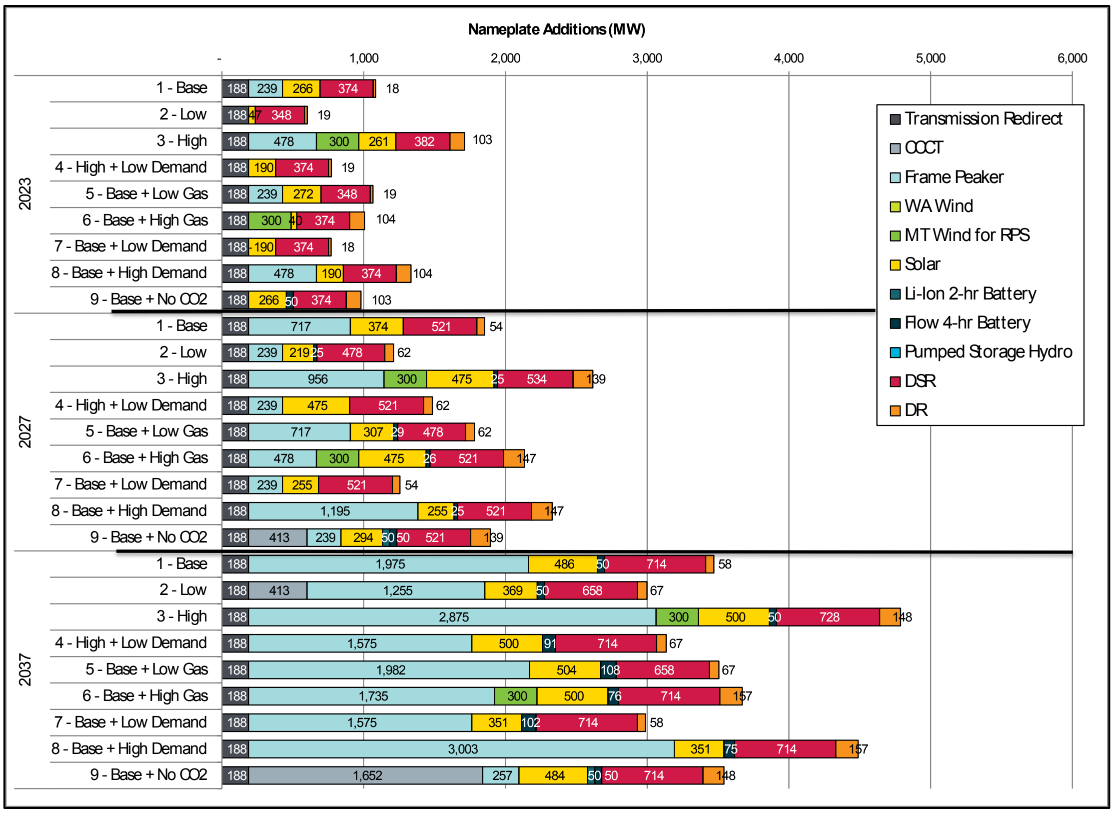
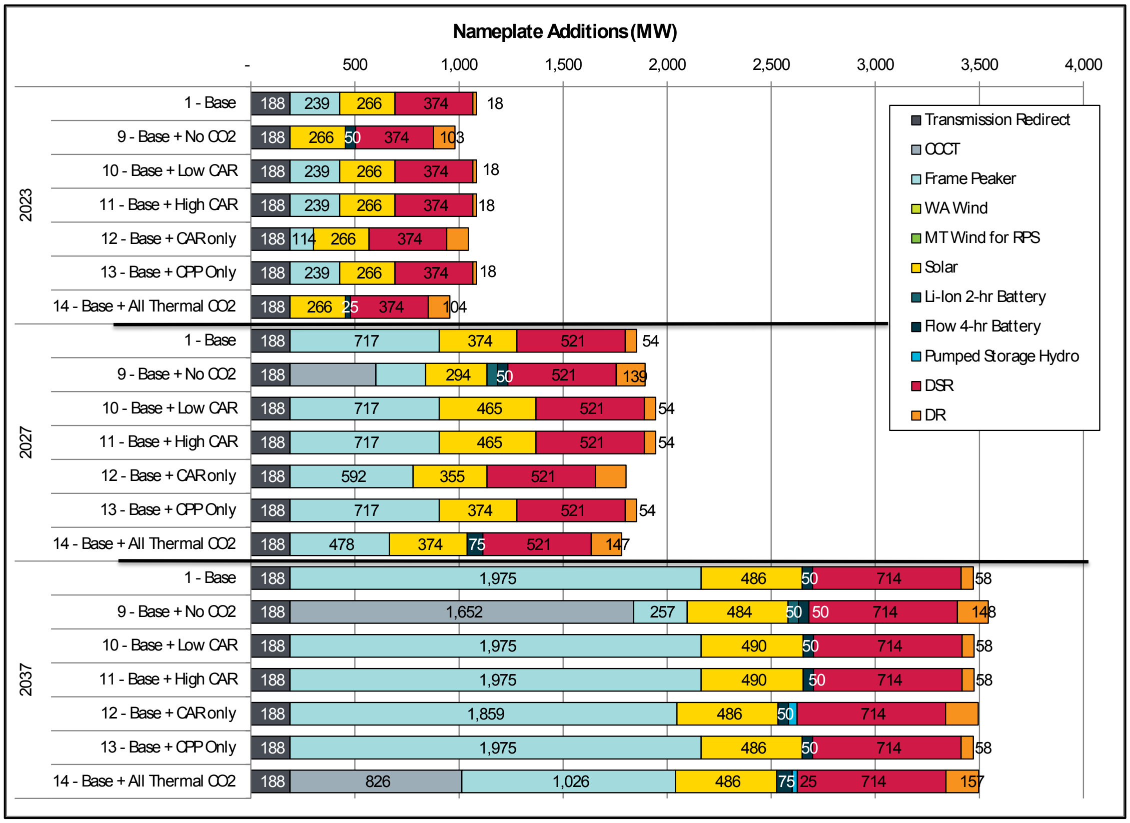


Figure 6-15 (continued)

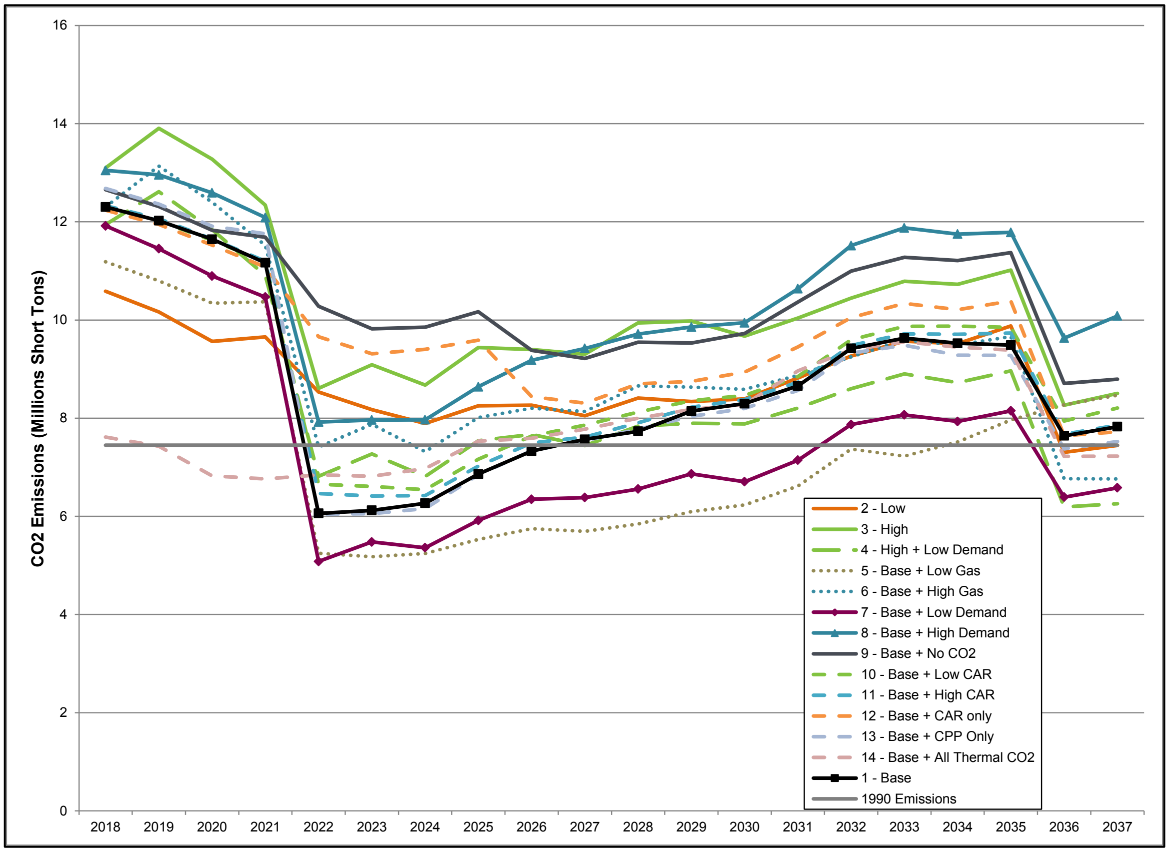
Scenarios 9-14



Portfolio Emissions

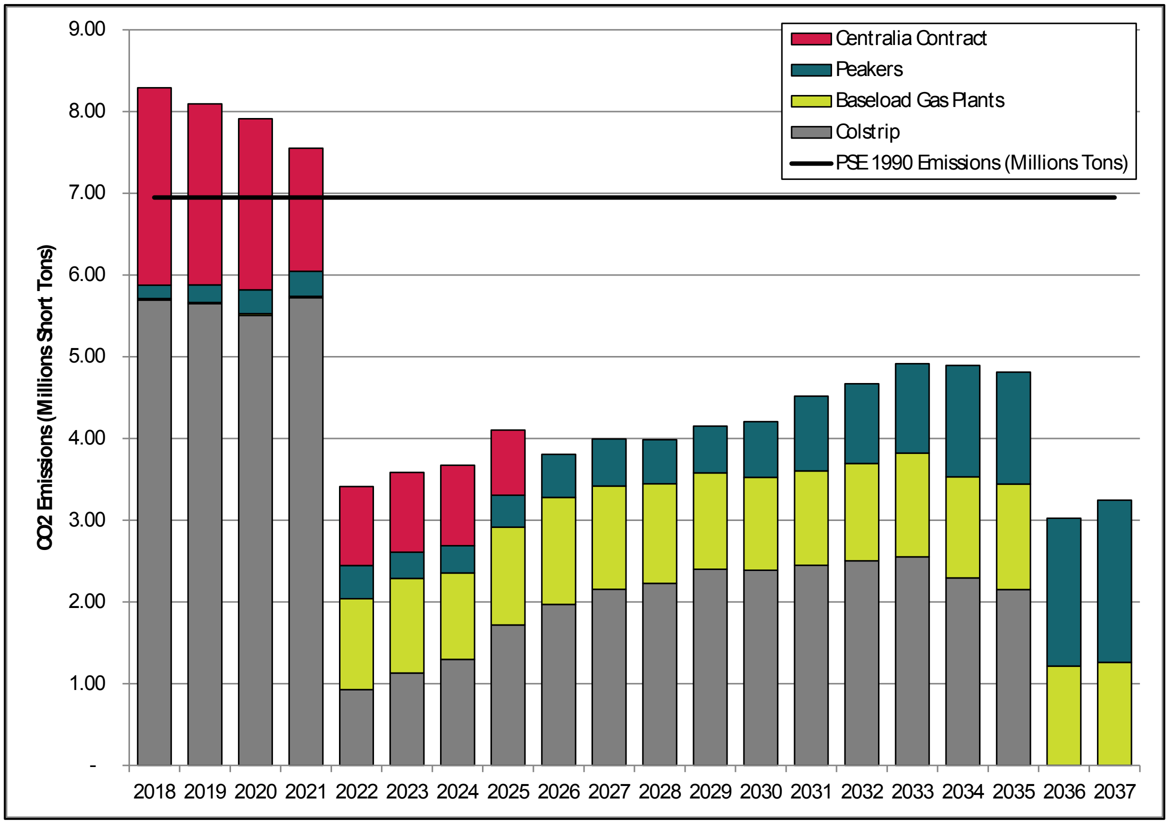
In this section we present results of our "portfolio emissions" analysis. An important detail is that this chart applies an average annual carbon intensity to the market purchases that make up nearly a third of PSE's portfolio. PSE's approach to accounting for market purchases is to calculate a WECC-wide average carbon intensity forecast in tons of CO_2 per MWh for each year in the planning horizon, and apply that average to market purchases. This is similar to the method used by the WUTC's compliance protocol, but that protocol uses the Northwest Power Pool average instead of the WECC average. Because this analysis applies an average emission rate, not a marginal emission rate, comparing these different lines will not accurately forecast how total emissions will change. In reality, changes in emissions will be impacted by marginal resource decisions (i.e., which resources are being dispatched, not average resource dispatch). For example, under the CAR, it may appear that PSE's emissions will go down, but under CAR, PSE's highly efficient baseload gas plants would ramp down and other, less efficient gas plants in the WECC would ramp up, for a net increase in carbon emissions. Increasing carbon emissions is clearly not the intended goal of CAR – but one could draw that conclusion from examining portfolio emissions only. A more reliable carbon analysis is presented in the section on carbon abatement costs. Figure 6-16 shows CO_2 emissions for the least-cost portfolio in each scenario.

Figure 6-16: CO_2 Emissions by Portfolio



Examining direct carbon emissions of PSE's portfolio may be more helpful, as it avoids the complications of addressing market purchases. Figure 6-17, below, shows the breakdown of emissions by resource type for the resource plan. The chart illustrates that PSE's emissions are driven by dispatch of thermal plants. This chart shows PSE's direct emissions from our resources are expected to fall significantly. This drop is caused by retirement of Colstrip 1 & 2 in 2022 and a significant drop in the economic dispatch of Colstrip 3 & 4 (given a WECC-wide carbon price assumed to become effective in 2022). The final large drop is in 2035, when Colstrip 3 & 4 are retired.

Figure 6-17: PSE's CO_2 Emissions for the Resource Plan Forecast in the Base Scenario



Cost of Capacity

In the latter part of the planning horizon, peakers and baseload gas plants were the primary supply-side resources that appear cost effective at large scale. Energy storage appears cost effective in certain situations, based in part on their small scale and the flexibility and T&D benefits they deliver.

Whether peakers or baseload gas plants are most cost effective varies across some of the scenarios. Net revenue requirements were calculated by taking all capital and fixed costs of a plant and then subtracting the margin (market revenue less variable costs). This calculation lets one quickly compare how the model evaluated these resources.

- Peaking units were modeled with oil backup.
- Plants are assumed to be located on the west side of the Cascades.
- The levelized cost for the peakers and baseload gas plants was calculated over the 35-year life of the plant.

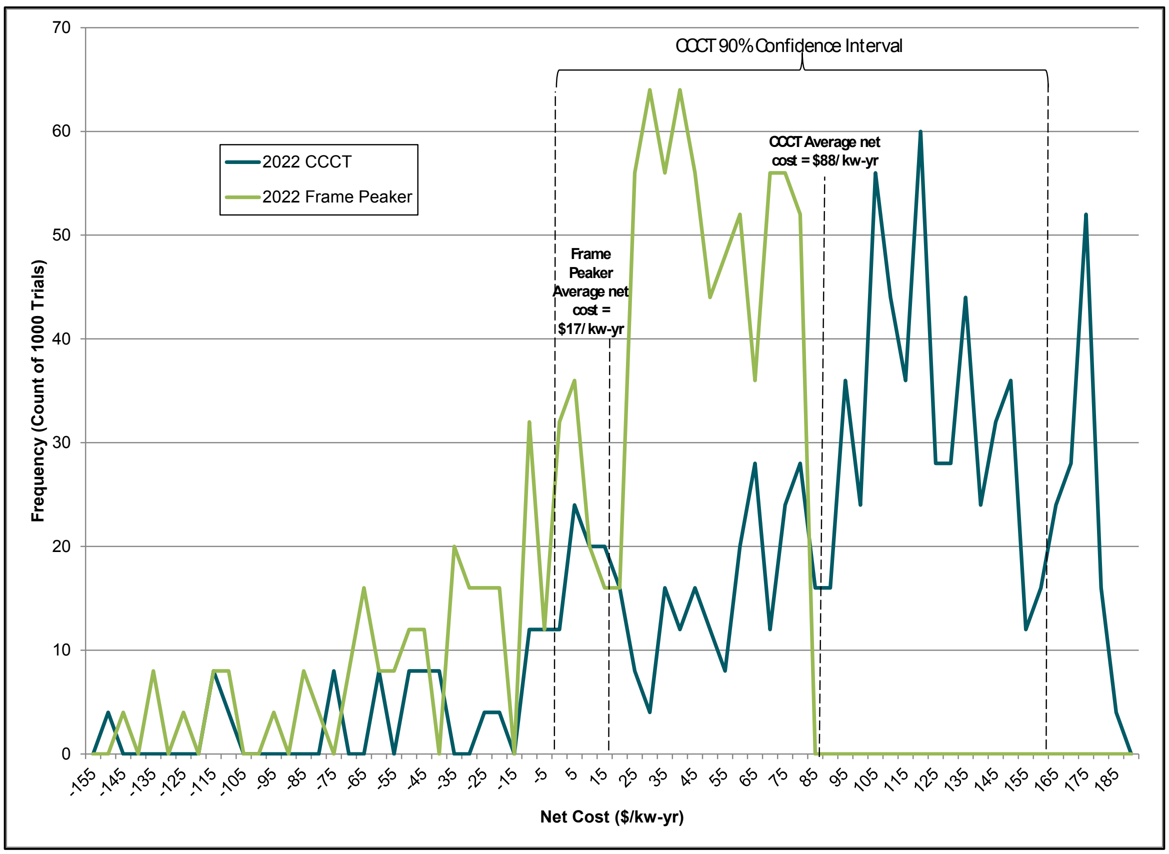
Figure 6-18 compares the cost of peakers and baseload gas plants across scenarios. In the scenarios where the baseload gas plants look more cost effective, the dispatch of the baseload plants is high, so the plant produces a lot of excess power to sell into the market; this creates revenue that lowers the net cost of the plant to customers, resulting in baseload gas plants being chosen in the lowest cost portfolio. Frame peaker costs vary across scenarios depending on the CO_2 regulation modeled. In the scenario where a *CO_2* price is applied to baseload plants only, the peakers are more valuable and more frequently dispatched, resulting in a lower net cost. In the Base + No CO_2 and the All-thermal CO_2 Scenarios, where peakers and baseload plants are treated equally, peakers dispatch less and therefore have a higher net cost.

Figure 6-18: Peaker and Baseload Gas Net Costs Compared

	Levelized Net Cost (2018 $/kW)	2022 CCCT	2022 Frame Peaker	2022 Aero Peaker	2022 Recip Peaker
1	Base	131	64	106	125
2	Low	122	76	119	153
3	High	101	64	105	119
4	High + Low Demand	138	71	112	137
5	Base + Low Gas Price	142	60	104	122
6	Base + High Gas Price	124	69	110	131
7	Base + Low Demand	143	66	108	131
8	Base + High Demand	100	54	96	103
9	Base + No CO2	87	75	117	148
10	Base + Low CO2 w/ CPP	121	59	100	116
11	Base + High CO2	126	61	103	120
12	Base + Mid CAR only (electric only)	139	72	114	140
13	Base + CPP only (electric only)	135	66	109	130
14	Base + All-thermal CO2 (electric only)	107	76	118	151

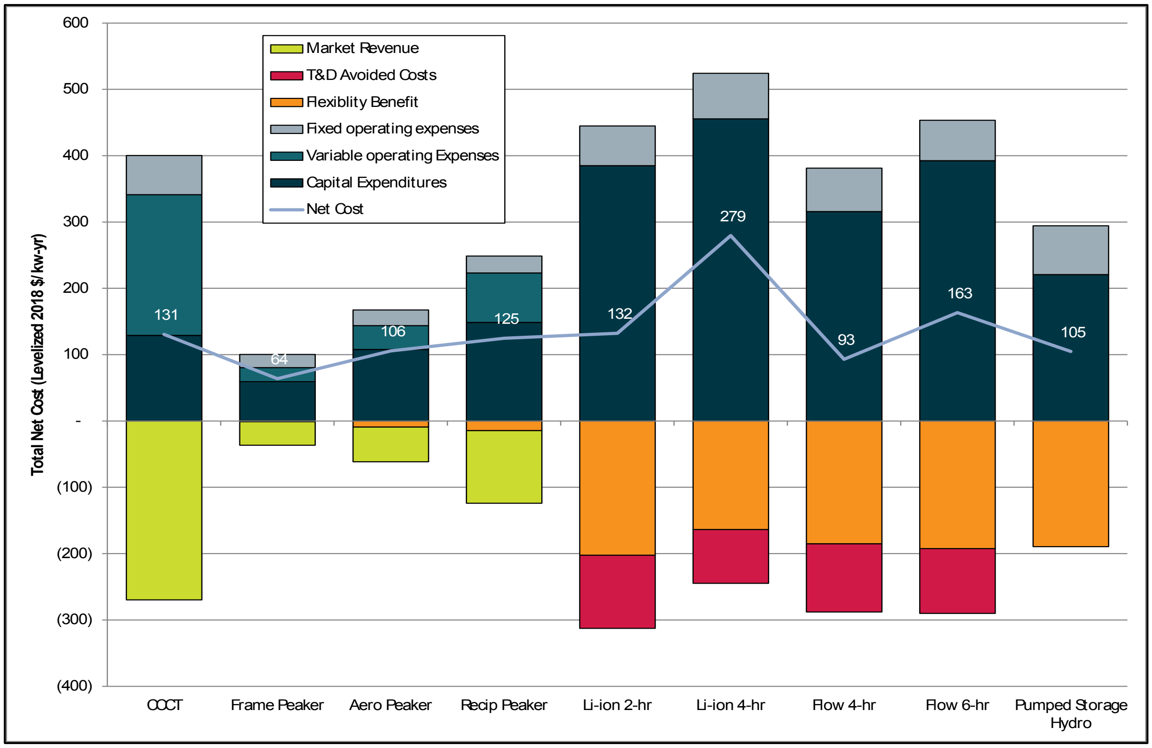
Net cost is not specifically used as part of the cost minimization function; however, showing net cost may provide useful insights. Figure 6-19 illustrates how the net cost of a baseload gas plant is significantly affected by the margin it generates. A 250-simulation Monte Carlo analysis for a 2022-vintage plant shows how the net cost per kW of peakers and baseload plants are distributed under different market conditions. The margins for both baseload gas plants and peakers are widely dispersed; this spreads out the probability distribution more broadly.

Figure 6-19: Comparison of Net Cost Distribution
Baseload Gas and Peakers with Oil Backup (in 2018 dollars per kW)



Peakers, baseload gas plants and energy storage resources traded off being the lower cost resource, depending on the scenario. Figure 6-20 compares the cost of peakers, baseload gas plants and energy storage resources in the Base Scenario. In this IRP, the flexibility benefit was only evaluated in the Base Scenario, so the net cost of the resources did not vary across scenarios. We assumed the avoided transmission and distribution cost from the Council's 7th power plan, and this benefit reduces the net cost of the 4-hour flow battery by $103/kW-yr. Avoided T&D cost is a large driver in making the battery a cost effective resource.

Figure 6-20: Net Cost of Capacity in the Base Scenario



As shown in the Figure above, the net cost of the frame peaker is the lowest cost resource, closely followed the 4-hour flow battery. Since these resources are so close in costs, many scenarios have a flow battery as the first build in 2023 instead of the frame peaker.

Backup Fuel Capacity

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.

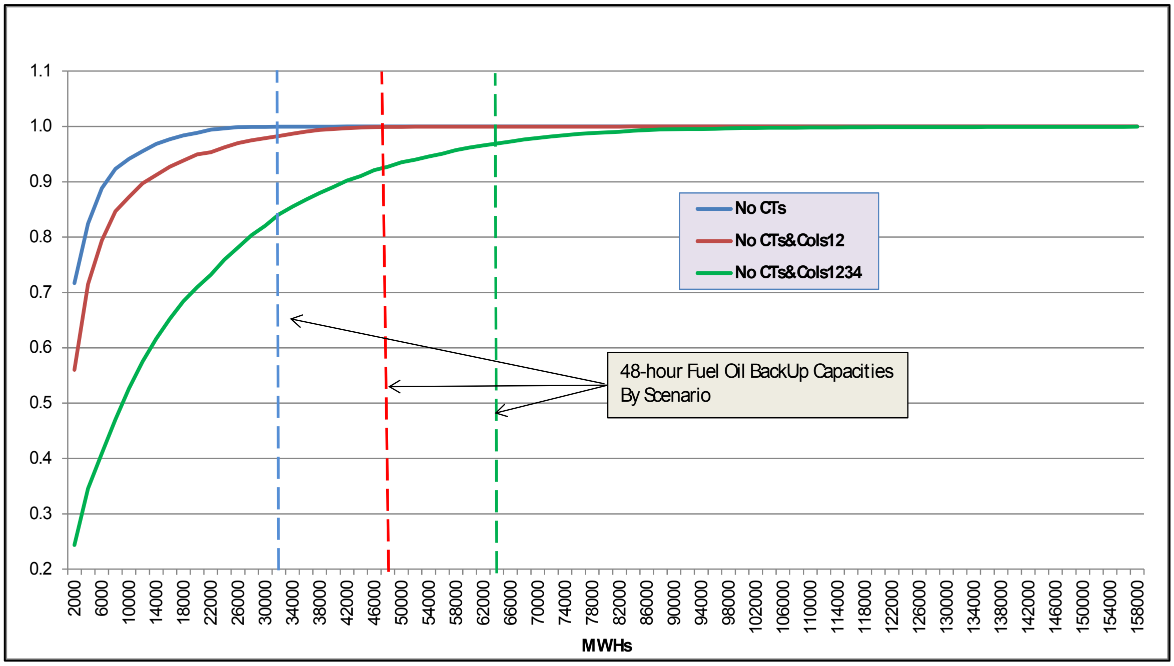
To determine if the results of the analysis are invariant to the scale of the capacity that is not available to meet resource adequacy, three scenarios were examined.

> **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.

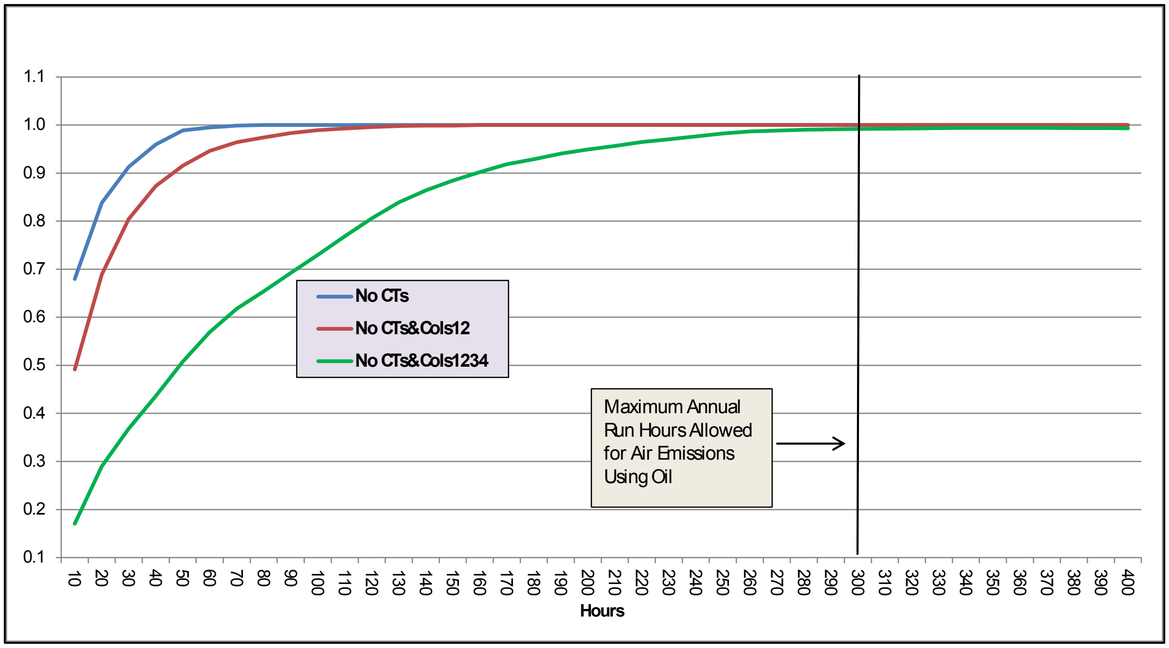
The chart below shows the cumulative distribution of MWhs resulting from the incremental outage events for each of the three scenarios. The higher the level of capacity that is unable to run due to the lack of gas supply, the greater the amount of deficit MWhs. This is shown by the rightward shift in 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 6-21: Cumulative Distribution of Incremental Deficit for Bad Simulations in MWh/yr



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 6-22: Cumulative Distribution of Incremental Deficit for Bad Simulations (in MWhs/year)



Renewable Builds

The amount of renewable resources included in portfolios is driven by RPS requirements. In all but the High and Base + High Gas Price Scenarios, solar resources are only added to meet the minimum requirements of RCW 19.285, not because they are least cost. See Figure 6-14 above for total solar builds by scenario.

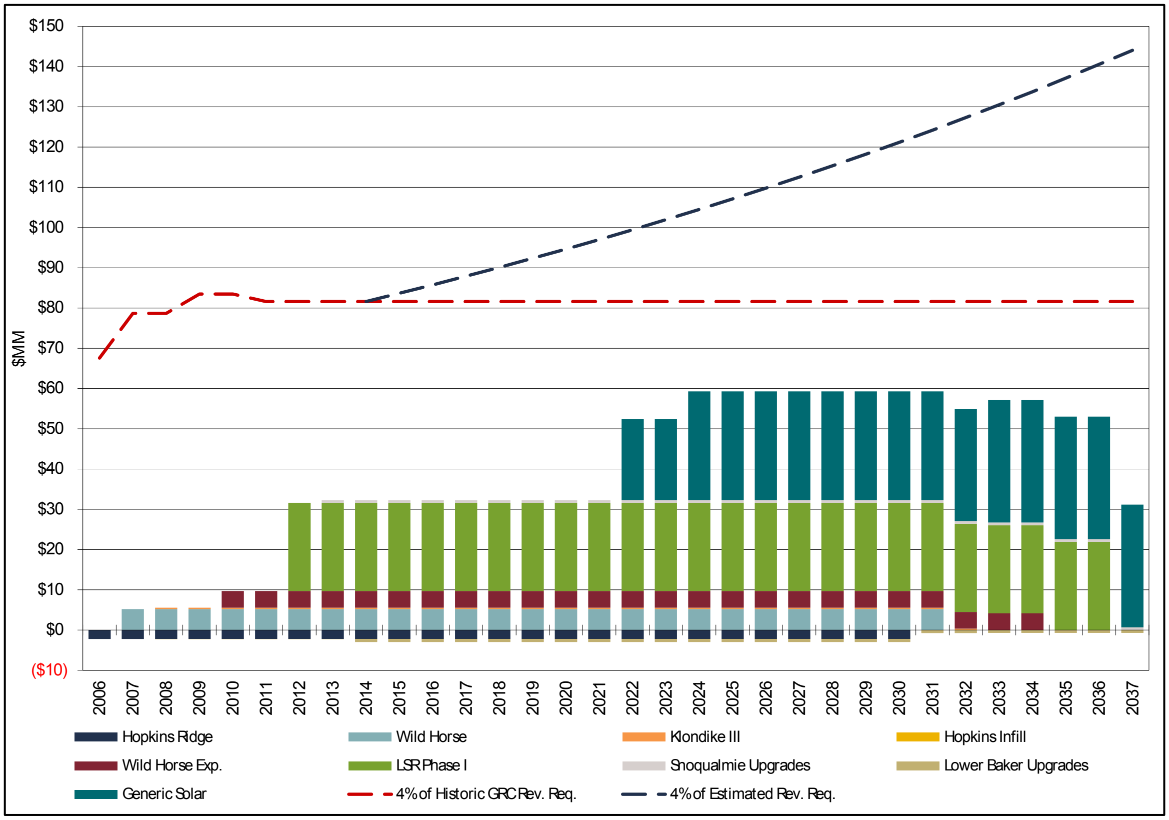
RPS Incremental Cost Cap Analysis

As part of RCW 19.285, if the incremental cost of the renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then the utility will be considered in compliance with the annual renewable energy target.[10]

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 6-23 presents results of this analysis for existing resources and projected resources. This demonstrates that 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.

10 / RCW 19.285.050 (1) (a) (b) "The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that does not qualify as eligible renewable resources."

Figure 6-23: Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4% of 2011 GRC Revenue Requirement + 2014 PCORC Adjustment

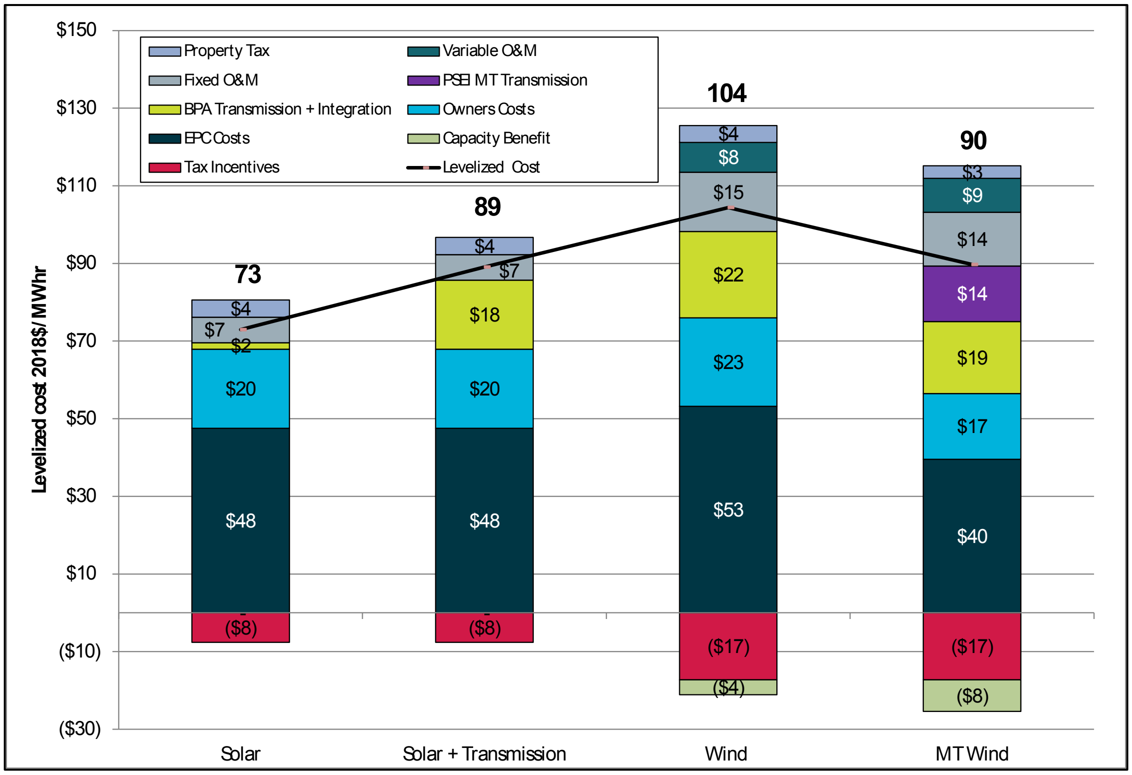


Renewable Resource Costs

Renewable resource costs are in flux. Over the last decade, photovoltaic technology costs have declined to the point that this technology now appears to be lower cost than wind. Figure 6-24 compares wind and solar cost components. Solar resources have a lower capacity factor, but also a lower capital cost, making them the lowest cost renewable resource. Assuming solar resources could be built in eastern Washington and interconnected to PSE's system, they would have no transmission cost and a total levelized cost of $73/MWh. Even if solar resources were located where they were burdened with BPA transmission costs, they still appear to be the lowest cost resource at this time.

The next lowest cost renewable resource is Montana wind. Due to its higher capacity factor, the $/MWh capital cost for Montana wind is lower than for solar; however, Montana wind has to overcome significant transmission costs to get from Montana to PSE. Also, wind resources from eastern Montana do not qualify as a renewable resource under RCW 19.285. To qualify, Montana wind would have to be delivered to Washington state on a real-time basis without shaping or storage. It is unclear whether such a designation could ever be made. This is not a short-coming in the industry – it highlights that the law is inconsistent with how bulk transmission systems plan and operate systems. However, PSE assumed Montana wind could be a qualifying renewable resource to help understand whether the designation would make or break its cost effectiveness.

Figure 6-24: Wind and Solar Cost Components



7. SENSITIVITY ANALYSIS RESULTS

A. Colstrip

How do different retirement dates affect decisions about replacing Colstrip resources?

Baseline: Retire Units 1 & 2 mid-2022, Units 3 & 4 remain in service into 2035.
Sensitivity 1: Retire Units 1 & 2 in 2018.
Sensitivity 2: Retire Units 3 & 4 in 2025.
Sensitivity 3: Retire Units 3 & 4 in 2030.

This sensitivity tested a "replacement power" portfolio analysis that took Colstrip out of PSE's portfolio in the Base and Base + No CO_2 Scenarios, so that we could compare the different portfolio builds and costs.

KEY FINDINGS: Carbon regulation could render Colstrip Units 3 & 4 uneconomic. The key takeaway from this analysis is that carbon regulation has a much greater impact than specific retirement dates. We do not know when (or whether) comprehensive carbon regulation will be implemented across the WECC and we do not know the form of that regulation, which could significantly affect these findings.

BASELINE COLSTRIP SHUTDOWN DATES. The Base Scenario assumes the theoretical implementation of CPP carbon pricing in 2022, which severely restricts the economic dispatch of Colstrip Units 1 & 2. Economics would likely force the shutdown at the beginning of 2022 instead of mid-2022, which differs from the Base Scenario portfolio

The Base + No CO_2 Scenario assumes Colstrip Units 1 & 2 retire in mid-2022 and Units 3 & 4 retire in 2035.

ASSUMPTIONS. The costs for Colstrip operations include fixed and variable operations and maintenance, coal costs, capital costs, relevant taxes, transmission, operational and ongoing environmental costs past the shutdown date, and depreciation expenses. In the Base Scenario, the Washington Clean Air Rule (CAR) is assumed to affect Washington baseload gas plants from 2018-2021, and starting in 2022 the EPA Clean Power Plan (CPP) is assumed to affect all U.S. baseload gas and coal plants. When Colstrip units were retired early, depreciation expenses were changed to match retirement dates and avoided on-going capital costs were eliminated. The analysis did not reflect changes in amortization of transmission related capital costs, which may tend to slightly overstate the benefit of early retirement. The eastern interconnect contract expires in 2027, and the Garrison to PSE transmission contract (BPAT) is up for renewal in 2019.

COLSTRIP 1 & 2 RESULTS. Under the Base Scenario, retiring Colstrip Units 1 & 2 in 2018 would cost an additional $30 million in the Base Scenario or $14 Million in the Base + No CO_2 Scenario. The cost is greater in the Base Scenario is because of CAR. CAR adds a CO_2 cost to Washington baseload gas plants but not to other plants in the WECC, so its effect is to increase the relative value of Colstrip.

COLSTRIP 3 & 4 RESULTS. Carbon regulation could render continued operation of Colstrip 3 & 4 uneconomic, depending on how the regulation is structured. In the Base Scenario, in which the CPP adds a CO_2 price that affects the dispatch cost of the plant starting in 2022, retiring Colstrip 3 & 4 in 2025 would lower portfolio costs. Under these conditions, the power plant has a greatly reduced capacity factor and is not able to recover the cost of operating. In contrast, under the Base + No CO_2 Scenario in which there is no CO_2 price, Colstrip continues to operate at a high capacity factor and continues to hold value, so the portfolio costs more if the units are retired early.

Figure 6-25: Portfolio Cost Results, Colstrip Sensitivity ($ Millions)

	Base Scenario		Base + No CO2 Scenario	
	Portfolio Cost	Benefit/(Cost)	Portfolio Cost	Benefit/(Cost)
Base portfolio	$11,915		$10,442	
Colstrip 1&2 in 2018	$11,944	($30)	$10,456	($14)
Colstrip 3&4 in 2025	$11,766	$149	$10,647	($192)
Colstrip 3&4 in 2030	$11,833	$82	$10,462	($66)

B. Thermal Retirement

Would it be cost effective to accelerate the retirement of PSE's existing baseload gas plants?

Baseline: Baseload gas plants continue to run through the end of the time horizon.

Sensitivity 1: Baseload gas plants retire in 2031.

KEY FINDINGS. Carbon regulation could significantly diminish the value of PSE's baseload gas fleet. In the Base Scenario, some slight portfolio cost savings could be created by replacing those plants with peakers. However, the Base Scenario has a biased application of carbon regulation and even then, the cost benefits of retiring those plants are minor. The findings differ under the Base + No CO_2 and the Base + All-thermal CO_2 Scenarios, where carbon regulation extends to peakers as well as baseload natural gas plants. It does not appear PSE needs to plan on retiring its baseload gas plants in the near future, but the issue should be re-examined as regulations and technologies evolve.

SUMMARY. This sensitivity was run in three scenarios: Base, Base + No CO_2, and Base + All Thermal CO_2. In the Base Scenario, baseload gas plant capacity factors decline significantly. The exact opposite happens in the Base + No CO_2 Scenario and Base + All Thermal CO_2 where the capacity factor is in the 80 percent range. The sensitivity retired each plant in 2031 and replaced it with a frame peaker (the lowest cost resource in the Base Scenario portfolio). Figure 6-26 below compares the cost of continuing to run the baseload plant vs. retirement. The baseload plants are burdened with firm pipeline costs, whereas the frame peakers are not. Also, Mint Farm and Goldendale both incur transmission charges on BPA's system, because those plants are outside PSE's balancing authority. Under the Base Scenario, it is cost effective to retire the baseload gas plants and replace them with frame peakers because the CO_2 regulation affects only baseload CCCT plants, except for Ferndale. Under the Base + No CO_2 and Base + All Thermal CO_2 scenarios, it is cost effective to keep the baseload gas plants running.

Figure 6-26: Impact of Early Closure for PSE's Baseload Gas Plants in 2031 ($ Millions)

	Base Scenario		Base + No CO2 Scenario		Base + All Thermal CO2	
	Portfolio Cost	Benefit/ (Cost)	Portfolio Cost	Benefit/ (Cost)	Portfolio Cost	Benefit/ (Cost)
Base portfolio	$11,982		$10,705		$12,644	
Encogen	$11,975	$7	$10,721	($16)	$12,668	($4)
Ferndale	$12,013	($31)	$10,787	($82)	$12,702	($38)
Goldendale	$11,971	$11	$10,782	($77)	$12,663	$1
Mint Farm	$11,974	$6	$10,805	($100)	$12,664	$0
Sumas	$11,977	$5	$10,795	($90)	$12,665	($2)

C. No New Thermal Resources

What would it cost to fill all future need with resources that emit no carbon?

Baseline: Fossil fuel generation is an option in the optimization model.

Sensitivity 1: Renewable resources, energy storage and DSR are the only options for future resources.

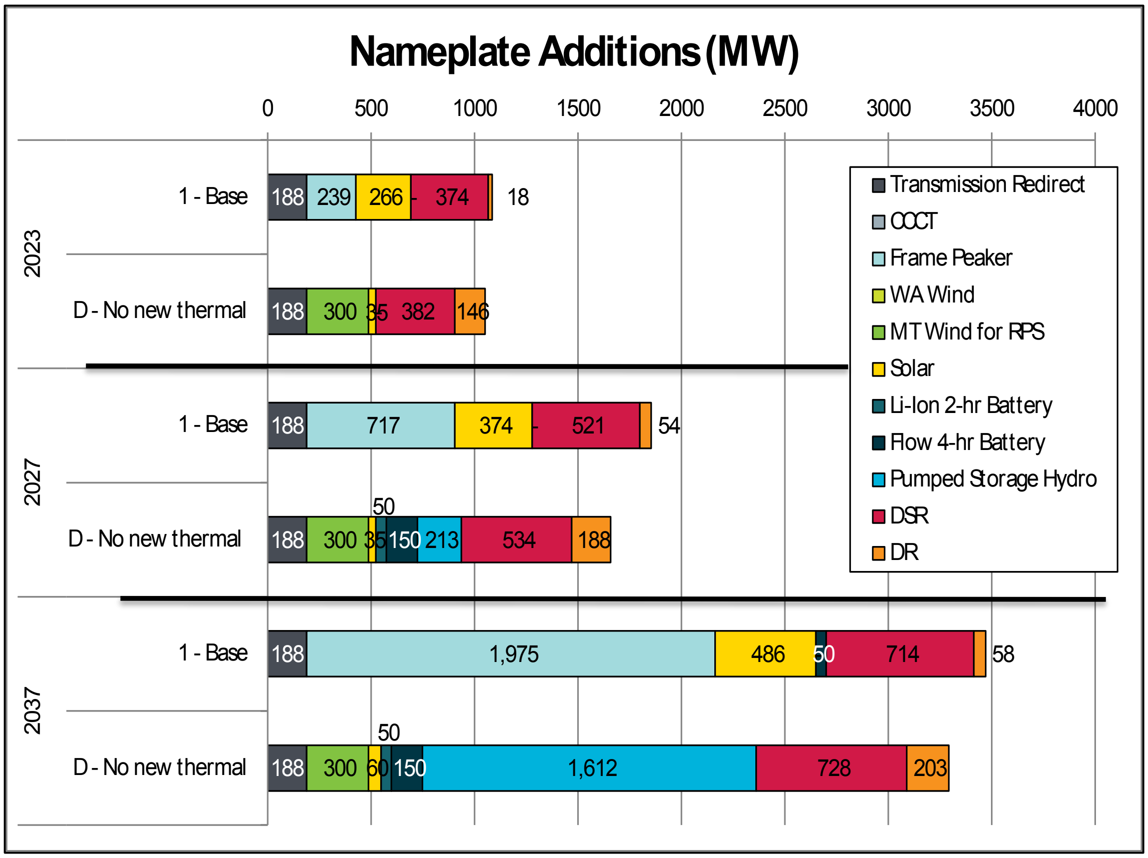
KEY FINDINGS. Adding no new thermal resources to the portfolio in the latter part of the planning horizon would increase both cost and risk, given current forecasts for resource costs, although those costs may change. To fill the gap, Montana wind and over 1,600 MW of pumped hydro storage would be needed. Additional analysis would be required to determine what kinds of operational issues this could create. For example, pumped hydro may provide flexibility benefits, but 1,600 MW of pumped hydro could create concerns about energy constraints.

SUMMARY. With no new thermal resources available, the only resource large enough to meet the capacity need is pumped storage hydro. This sensitivity analysis adds another DSR bundle to the portfolio (compared to the Base Scenario portfolio) and adds all the available demand response. It also switches the renewable resource to Montana wind because of Montana wind's capacity advantage over solar. This portfolio costs $1.36 billion more than the Base Scenario portfolio.

Figure 6-27: No New Thermal Portfolio Cost ($ Millions) and Builds (Nameplate MW)

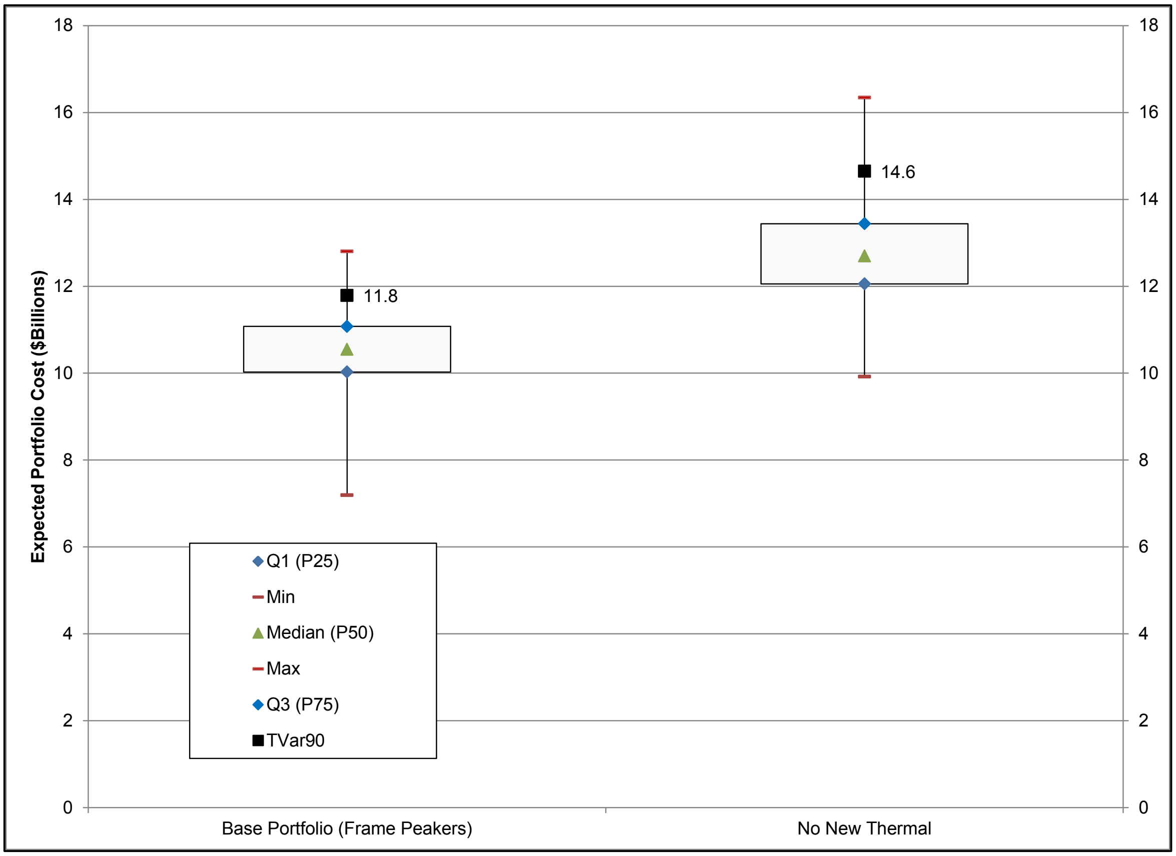
Portfolio Cost ($Millions)	NPV
1 – Base	$11,981
D – No New Thermal Resources	$13,343
Difference in Cost	**$1,362**

Figure 6-28: Nameplate Additions, No New Thermal Resources Sensitivity



A portfolio with no new thermal resources is also a high risk portfolio as shown in Figure 6-29, which compares expected costs and cost ranges. The TVar90 of the portfolio with no new thermal is $2.8 billion more than the Base Scenario portfolio that includes frame peakers.

Figure 6-29: Effect of No New Thermal Resources on Costs and Risks



D. Stakeholder-requested Alternative Resource Costs

What if capital costs of resources are different than the base assumptions?

Baseline: PSE cost estimate for generic supply-side resources.

Sensitivity 1: Lower cost for recip peakers.

Sensitivity 2: Higher thermal capital costs.

Sensitivity 3: Lower wind and solar development costs.

Sensitivity 4: Apply more aggressive solar cost curve.

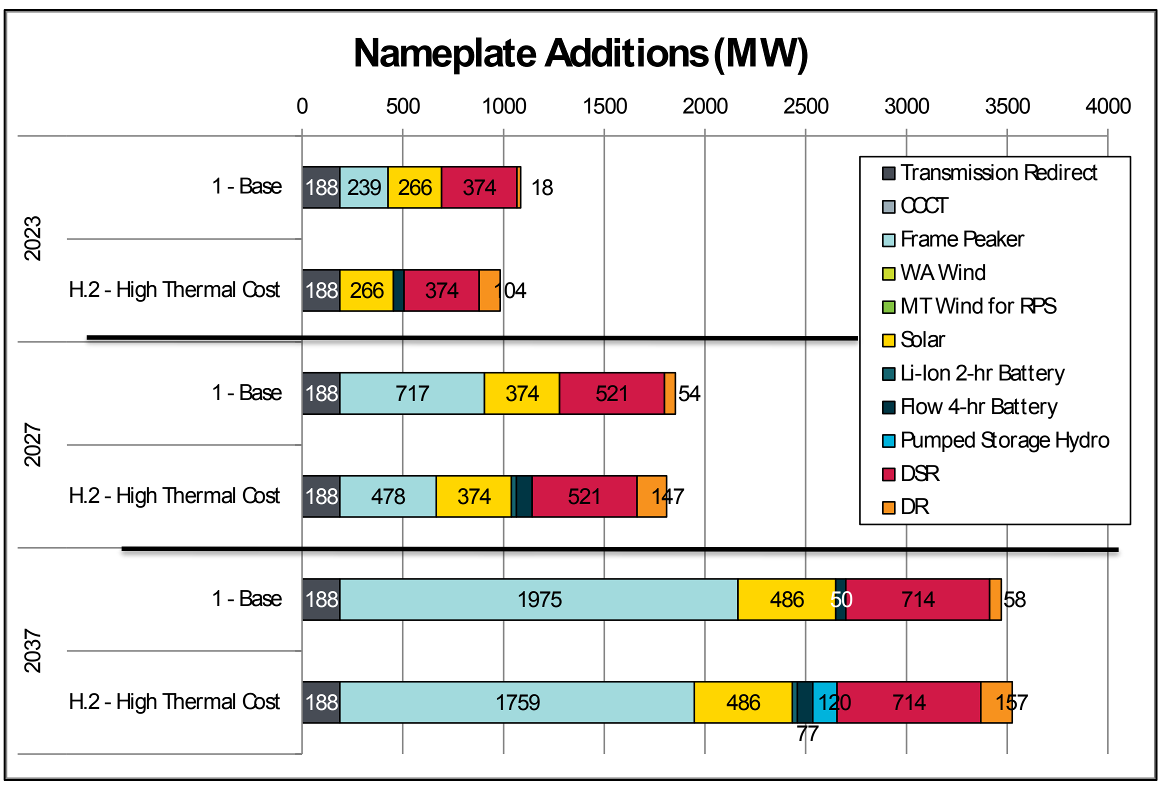
SENSITIVITY 1: LOWER COST FOR RECIP PEAKERS. This sensitivity tested a lower capital cost of recip peakers of $1,257/kW for a dual fuel unit with oil backup. This change did not affect the least-cost mix of resources. The total capital cost of the recip peakers would have to be reduced by more than 15 percent (to approximately $1,054) to be cost competitive. Additionally, it is not clear whether a dual fuel recip peaker could meet current air emissions standards. The analysis illustrates that further analysis into this issue is not warranted.

SENSITIVITY 2: HIGHER THERMAL CAPITAL COSTS. This sensitivity tested higher thermal capital costs from the 2015 IRP.

Frame peaker with oil: $879 per kW
Recip peaker: $1,563 per kW
Aero peaker with oil: $1,214 per kW
Baseload CCCT: $1,227 per kW

The result was that battery storage plus higher demand response was added in 2023 instead of a frame peaker; then frame peakers were added to meet capacity need starting in 2025. This result is consistent with the resource plan forecast. Total portfolio cost increased by $213 million.

Figure 6-30: Higher Thermal Cost Portfolio Builds



SENSITIVITY 3: LOWER WIND AND SOLAR DEVELOPMENT COSTS. This sensitivity used the lower development costs from the DNV GL study which is included as Appendix M.

Wind: $1,478 per kW (2016 $)
Solar: $1,755 per kW (2016 $)

Lower wind and solar development costs did not change the optimal portfolio. Solar is still added to only to meet the renewable need under RCW 19.285. Because the solar cost curve is much lower than the wind cost curve at this time, wind capital costs would have to drop by 44 percent to $1,210 per kW (in 2022 dollars) to be cost competitive with solar.

SENSITIVITY 4: APPLY MORE AGGRESSIVE SOLAR COST CURVE. When this sensitivity was developed in consultation with external stakeholders, we had not anticipated that base solar costs would be more cost effective than wind. We continued pursuing this sensitivity to determine whether solar costs could become lower cost than market using the more aggressive solar costs developed by the Northwest Energy Coalition.

With the more aggressive cost curve on solar, the levelized cost of a 2023 resource drops to $58/MWh instead of $73/MWh for the baseline assumption. The portfolio builds under this sensitivity do not change, but the total portfolio cost is down to $11.64 billion. This is a decrease of $340 million from the Base Scenario portfolio.

E. Energy Storage

What is the cost difference between a portfolio with and without energy storage?

Baseline: Batteries and pumped hydro included only if chosen economically by the analysis.
Sensitivity 1: Add 50 MW battery in 2023 instead of economically chosen peaker.
Sensitivity 2. Add 50 MW pumped hydro storage in 2022 instead of economically chosen peaker.

MODIFICATION OF SENSITIVITY. This sensitivity was developed in consultation with external stakeholders before results of the portfolio analysis showed batteries as cost effective across all scenarios. Since the resource plan includes 50 MW of batteries by 2023, we modified this sensitivity to examine the cost impact of using pumped hydro storage in 2023 rather than a flow battery.

KEY FINDINGS. Pumped hydro storage would be slightly more expensive than batteries. However, 50 MW is a very small change. A key value stream from batteries is the ability to create transmission and distribution benefits that cannot be derived from pumped hydro.

Batteries

Historically, electricity is consumed immediately after it is created. The emergence of a new generation of advanced batteries which allow for storage on the grid has led to the first instances of large-scale energy storage being implemented in the electric distribution network. Batteries can also provide ancillary services such as spinning reserves and frequency regulation, along with peak capacity.

Pumped Hydro Storage

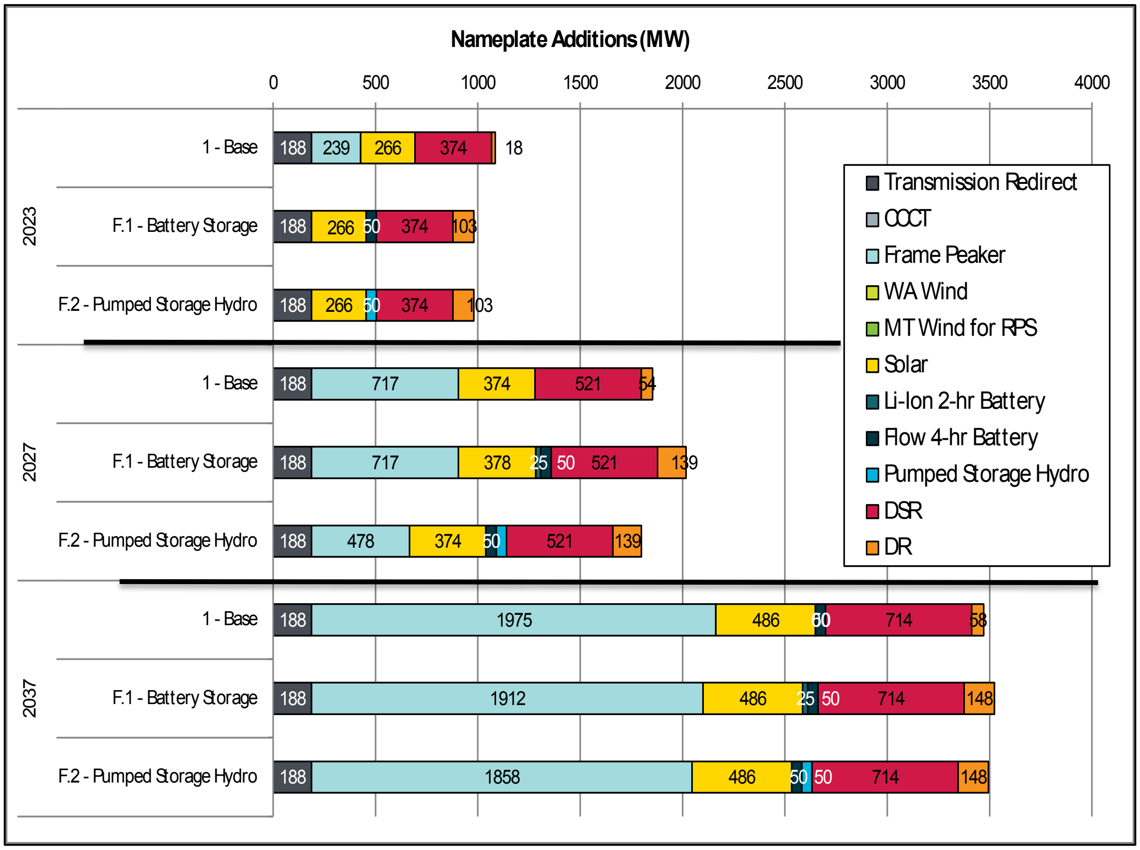
Pumped hydro is a proven storage technology that can also provide flexibility benefits. However, the facilities are expensive and may have controversial environmental impacts. Additionally, depending on where pumped hydro is located, transmission may be a challenge. Pumped hydro resources also may have more extensive permitting processes and require sites with specific topologic and/or geologic characteristics. On the positive side, if significant quantities of capacity are needed, pumped hydro resources may be more practical than batteries.

In this IRP, the total net cost of the pumped storage hydro project is $105/kW-yr as compared to $64/kW-yr for a peaker. Pumped storage projects are usually very large, so realistically PSE would have to partner with other owners for a share of the project. For example, the proposed JD Pool pumped storage hydro project in southern Washington is estimated to be 1,500 MW. The analysis tested adding 50 MW of pumped storage hydro plus more demand response in 2023, similar to the battery sensitivity. The total portfolio cost increased by $15 million in the Base Scenario.

Figure 6-31: Battery and Pumped Storage Portfolio Cost

	NPV Portfolio Cost ($Millions)	Difference from Base
Base Portfolio	11,981	
50 MW Battery in 2023	11,988	7
50 MW Pumped Storage Hydro in 2023	11,996	15

Figure 6-32: Portfolio Additions, Energy Storage Sensitivity



F. Renewable Resources + Energy Storage

Does bundling renewable resources with energy storage change resource decisions?

> **Baseline: Evaluate renewable resources and energy storage as individual resources in the analysis.**
>
> **Sensitivity: Bundle 50 MW battery + 200 MW solar.**

When a battery storage resource is paired with a renewable resource, then the battery storage could receive an investment tax credit (ITC) in addition to the renewable tax credit. If 100 percent of the energy from the renewable resource were used to charge the battery, then the battery would receive the full 30 percent ITC; if 75 percent of the energy from the renewable resource were used to charge the battery, it would receive a 22.5 percent ITC. However, the utility must prove that the energy is coming from the renewable resource. In order to do this the battery must be located near the renewable, which most likely negates any localized transmission or distribution benefits. Additionally, this limitation would constrain the ability to use the battery for sub-hourly flexibility, as the battery would be energy constrained. This analysis tests whether using a battery in this manner to receive the ITC is worth the loss of the T&D benefit and the reduced flexibility benefit.

KEY FINDINGS. Pairing batteries with solar does not appear cost effective because no additional peak capacity value is created. If anything, this would impair the peak capacity value of the battery, because the ability to charge it would be limited based on the solar output.

ASSUMPTIONS. The T&D avoided cost was removed and the flexibility benefit was reduced by 25 percent. The peak capacity value of the battery was not reduced for this analysis, but it did not appear cost effective, so such additional analysis was not warranted.

RESULTS. Total portfolio cost increased by $21 million. The T&D and flexibility benefit of the battery outweighed the ITC cost reduction. Figure 6-33 below compares the costs for a 4-hour flow battery combined with a solar resource under the baseline assumptions and the sensitivity assumption.

Figure 6-33: Cost of a 2022 4-hr Flow Battery (2018 $/kw-yr)

Net Cost ($/kw-yr)	Baseline	Sensitivity
Variable Operating Expenses	-	-
Fixed Operating Expenses	65	65
Capital Expenditures	316	213
Flexibility Benefit	(185)	(139)
T&D Avoided Cost	(103)	-
Total Net Cost	**93**	**140**

G. Electric Vehicle Load

How much does electric vehicle (EV) charging affect the loads and resource plan?

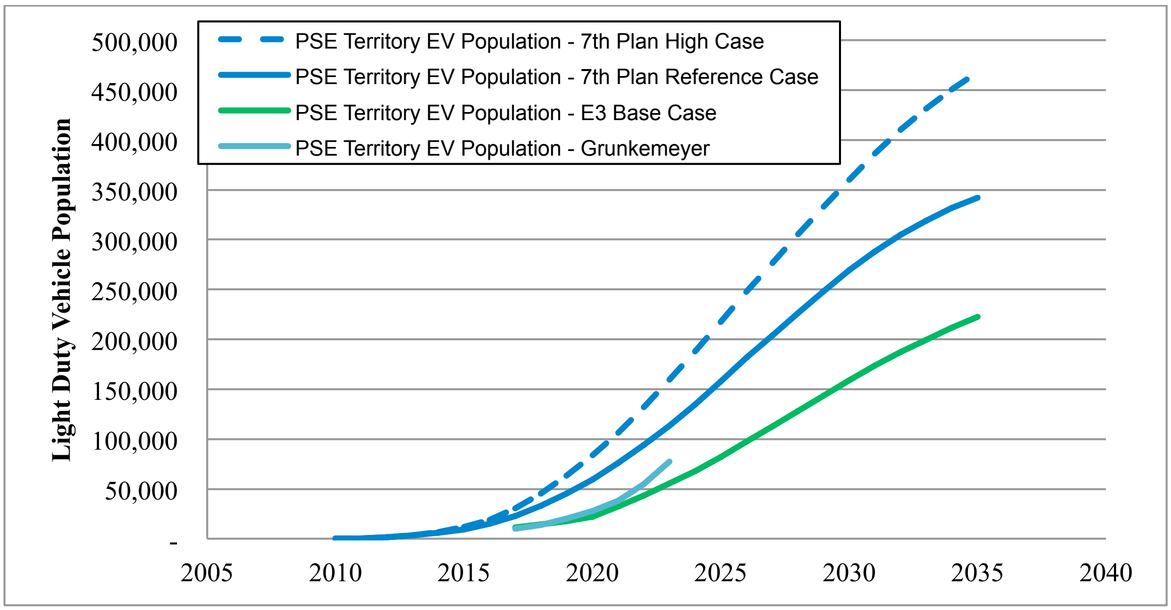
Baseline: IRP Base Demand Forecast.

Sensitivity: Add forecasted electric vehicle load.

KEY FINDINGS. An increase in electric vehicle charging in PSE's service territory will increase both energy and peak needs. To meet the increased energy need, by 2037 the portfolio has 277 MW more of frame peakers to meet peak capacity needs and 44 MW more of solar to meet the increase in renewable need.

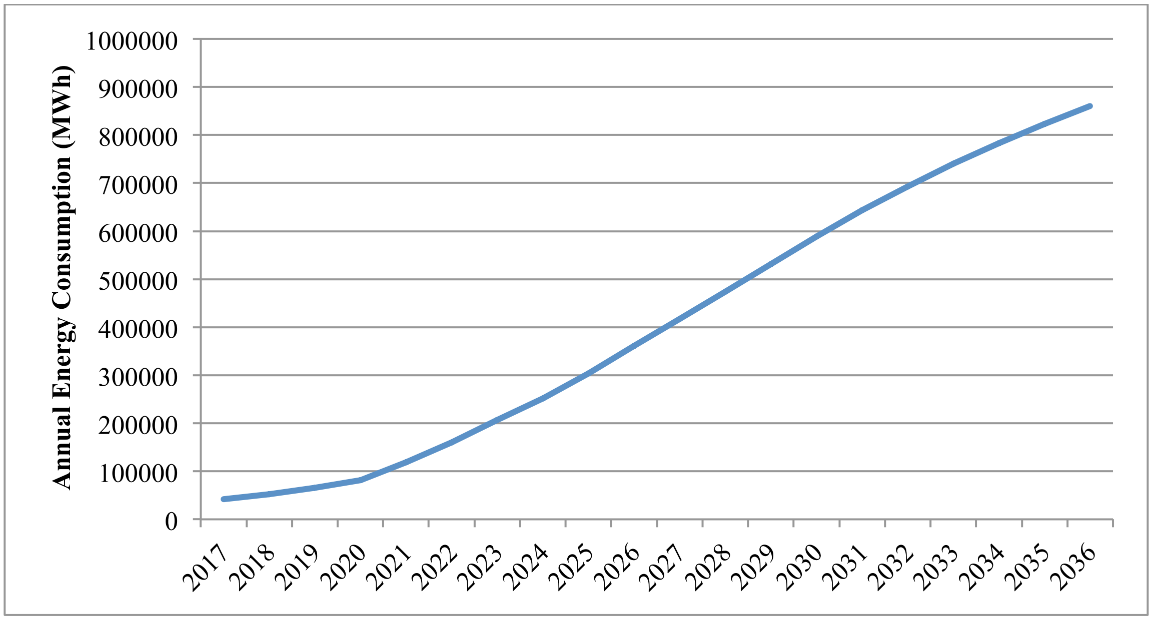
ASSUMPTIONS. This sensitivity models the impact of anticipated electric vehicle growth on resource needs. Currently, there are approximately 13,000 electric vehicles registered in PSE's electric service territory. The energy used in the sensitivity is built up from a forecast of the number of vehicles on the road and the charging patterns of the vehicles. The forward forecast for vehicles is based on joint work between PSE and Energy and Environmental Economics (E3). For Washington, the EV adoption curve starts with the plug-in electric vehicle (PEV) population as of the end of 2015 (according to the Washington State Department of Transportation, 2016), and it assumes a constant percentage population growth rate through 2020, meeting Governor Inslee's Results Washington goal of 50,000 PEVs in 2020. Between 2020 and 2030, annual sales of PEVs were assumed to have a constant, linear growth, reaching 15 percent of new passenger vehicle sales in 2030. This sales trajectory is consistent with PEV component cost reduction forecasts made by Ricardo PLC (PG&E, 2016). Annual PEV sales are then assumed to grow more slowly, at 2 percent per year until 2036. In this study, the total Washington State PEV population reaches 528,000 vehicles by 2036. PSE's population over this time was scaled from the state-level forecast based on its current percentage of the EV population in Washington State, which is 44 percent. This forecast is compared to several other forecasts scaled to PSE's service territory in Figure 6-34 below; it is more fundamentals-based than the other forecasts shown.

Figure 6-34: Light Duty Electric Vehicles in PSE's Service Territory, Forecast Comparison



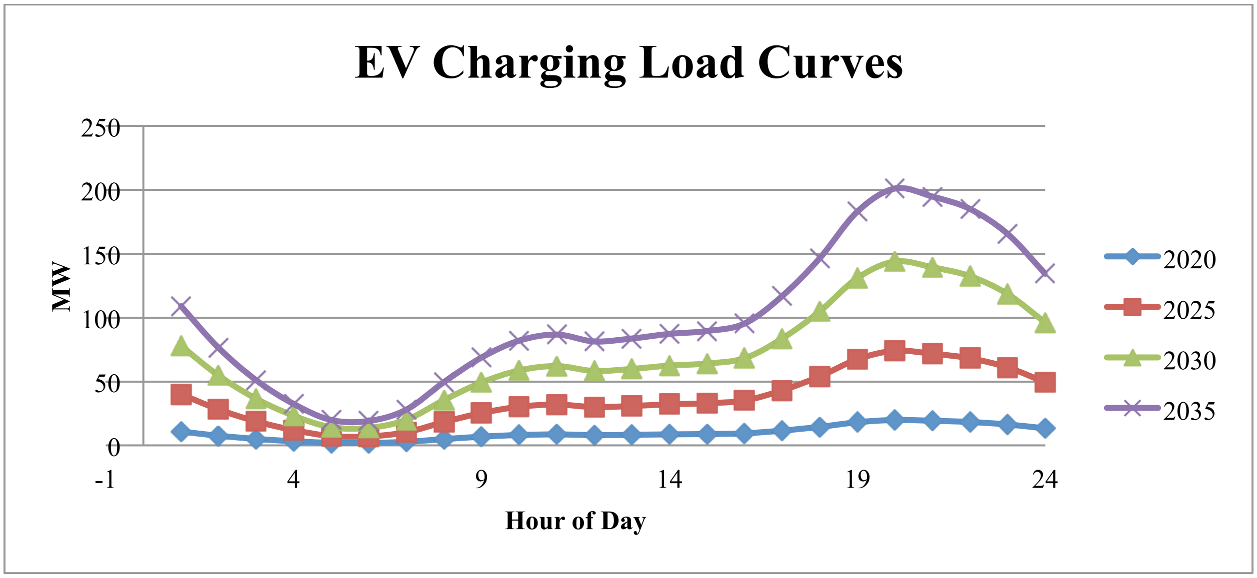
This vehicle forecast is translated to energy delivered using data on vehicle charging from the EV Project model of how electric vehicles are charged and how often that includes residential charging, workplace charging, public charging and fast public charging.

Figure 6-35: Electric Vehicle Annual Energy Consumption (MWh)



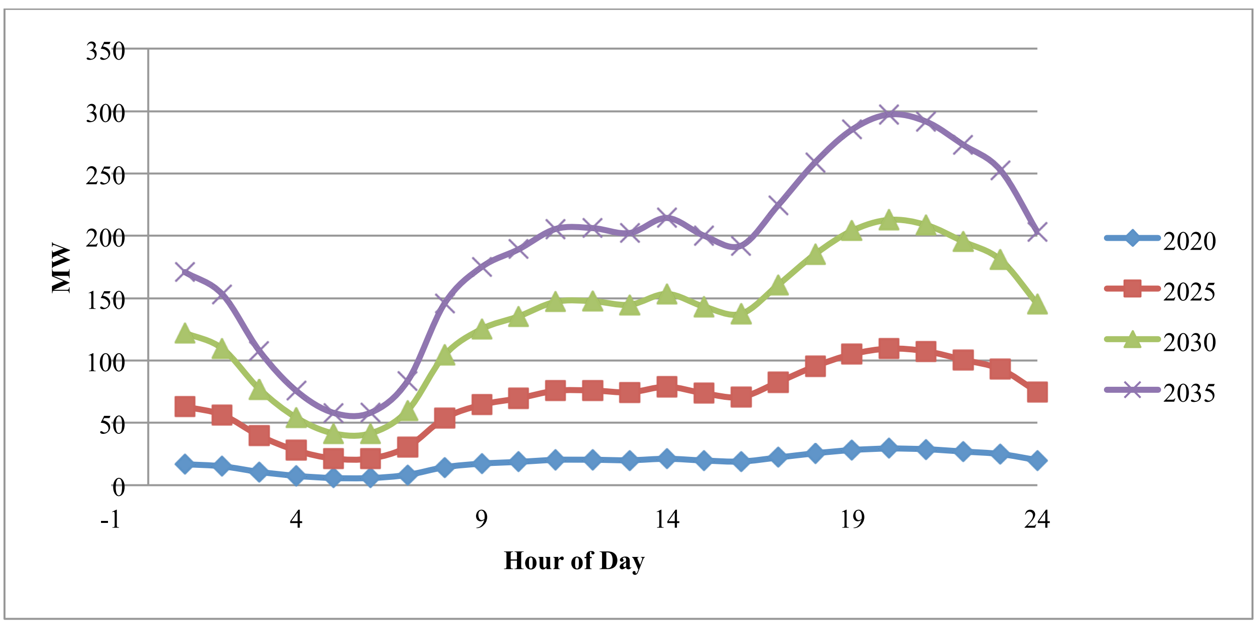
To develop the average load shape of the energy delivered, data from the EV Project and other sources were used to develop a time-based model of charging behavior that includes residential charging, workplace charging, public charging and fast public charging. The hourly profile for each of these types of charging was taken from the EV Project, and a model of how frequently each were used was applied. The result is an aggregate curve for charging. This curve, multiplied by the number of vehicles, provides the aggregate load curve used, which is shown for several time periods below. PSE anticipates updating the charging curve for residential charging based on its recent pilot project and will incorporate that into future analyses.

Figure 6-36: EV Charging Load Curves (MW)



Finally, an estimate of the necessary capacity was developed, which represents the highest power demanded by an aggregate population EVSEs (kW) over the course of 3 months. It is based on the highest aggregate demands observed in The EV Project and varies by weekend or weekday. PSE anticipates updating this capacity need based on its recently concluded residential electric vehicle pilot program.

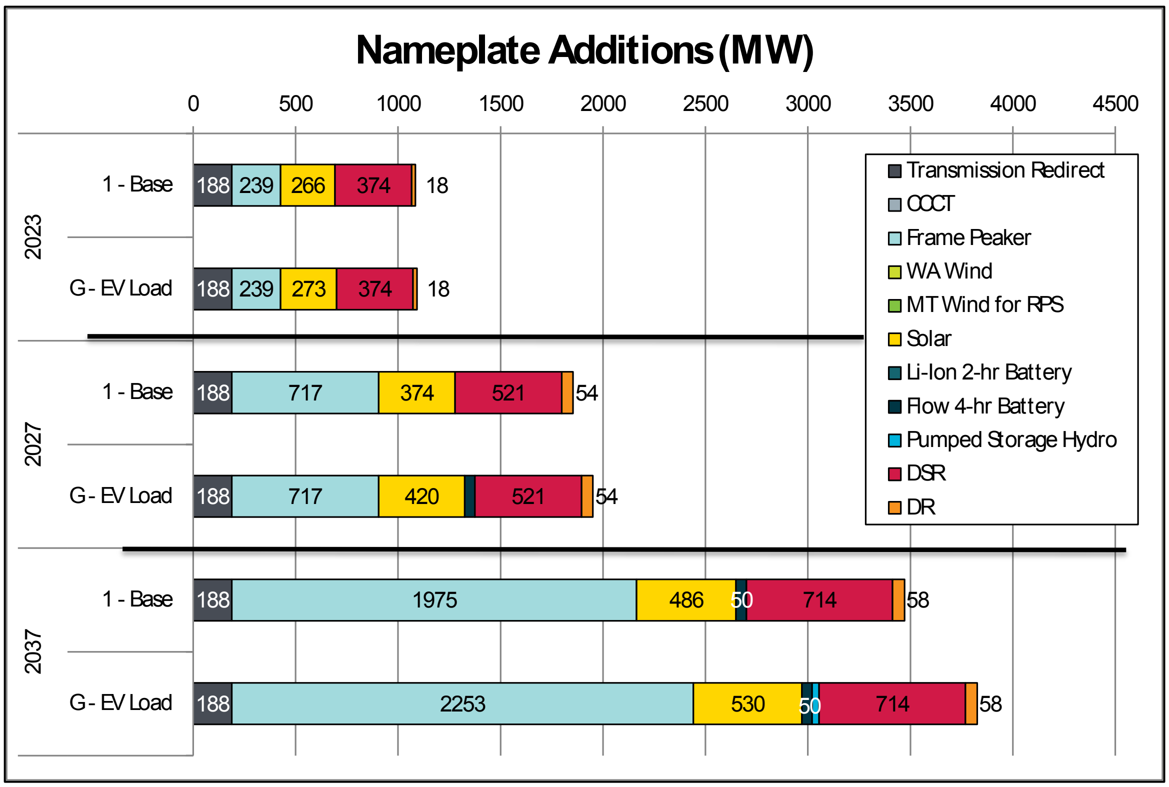
Figure 6-37: EV Charging Load Curves (Peak)



It is important to note that these capacity curves anticipate that nothing is done to change the capacity need. In reality, utility programs would seek to minimize peak capacity impacts of electric vehicle charging, as has been recently indicated by the WUTC as a priority in Docket UE-160799.

RESULTS. Figure 6-38, below, shows the total nameplate additions for a portfolio with the EV load added to the 2017 IRP Base Demand Forecast. Both the annual energy consumption and the December peak increased, resulting in the need for more energy and capacity resources. The total portfolio cost with the EV load is $12.3 billion, $362 million more than the Base Scenario portfolio.

Figure 6-38: Nameplate Additions, Electric Vehicle Load Sensitivity



I. Demand-side Resources (DSR)

How much does DSR reduce cost, risk and emissions?

Baseline: All cost-effective DSR per RCW 19.285 requirements.

Sensitivity: No DSR. All needs met with supply-side resources.

Demand-side resources were found to reduce both cost and market risk in portfolios.

Figure 6-39 shows the optimal DSR bundle in each scenario. The avoided cost of capacity (this includes energy, capacity and renewable resources) plays a big role in the selection of the optimal bundle. In particular, the avoided cost of energy varies depending on the power price included in the scenario. (Detailed results by scenario, including avoided cost calculations, are presented in Appendix N, Electric Analysis.)

Demand-side resources must be cost effective to be included in the plan, so by definition they are also least-cost resources. The Base Scenario deterministic least-cost portfolio includes 772 MW of DSR by 2037.

Figure 6-39: Optimal DSR Results across Scenarios
Capacity in MW by 2037

		DSM	Demand Response	DE	C&S	Total
1	Base	426	58	27	260	772
2	Low	371	67	27	260	725
3	High	441	148	27	260	876
4	High + Low Demand	426	67	27	260	781
5	Base + Low Gas Price	371	67	27	260	725
6	Base + High Gas Price	426	157	27	260	871
7	Base + Low Demand	426	58	27	260	772
8	Base + High Demand	426	157	27	260	871
9	Base + No CO2	426	58	27	260	772
10	Base + Low CO2 w/ CPP	426	58	27	260	772
11	Base + High CO2	426	58	27	260	772
12	Base + Mid CAR only (electric only)	426	157	27	260	871
13	Base + CPP only (electric only)	426	58	27	260	772
14	Base + All-thermal CO2 (electric only)	426	157	27	260	871

Demand response is a subset of DSR and is considered as part of determining the least-cost resources. A description of the demand response programs can be found in Appendix D, electric resources and Appendix J, Conservation Potential Assessment.

Figure 6-30 compares expected costs and cost ranges to illustrate how DSR reduces cost and risk in the portfolio. The amount of cost-effective conservation acquired varies across scenarios, but by 2035, the range is very tight, 725 MW to 876 MW. Compared to the Base Scenario portfolio with no DSR, the Base Scenario portfolio with DSR is lower cost and has a lower TVar90, which measures the risk of how costly a portfolio can get.

Figure 6-40: Effect of DSR on Costs and Risks

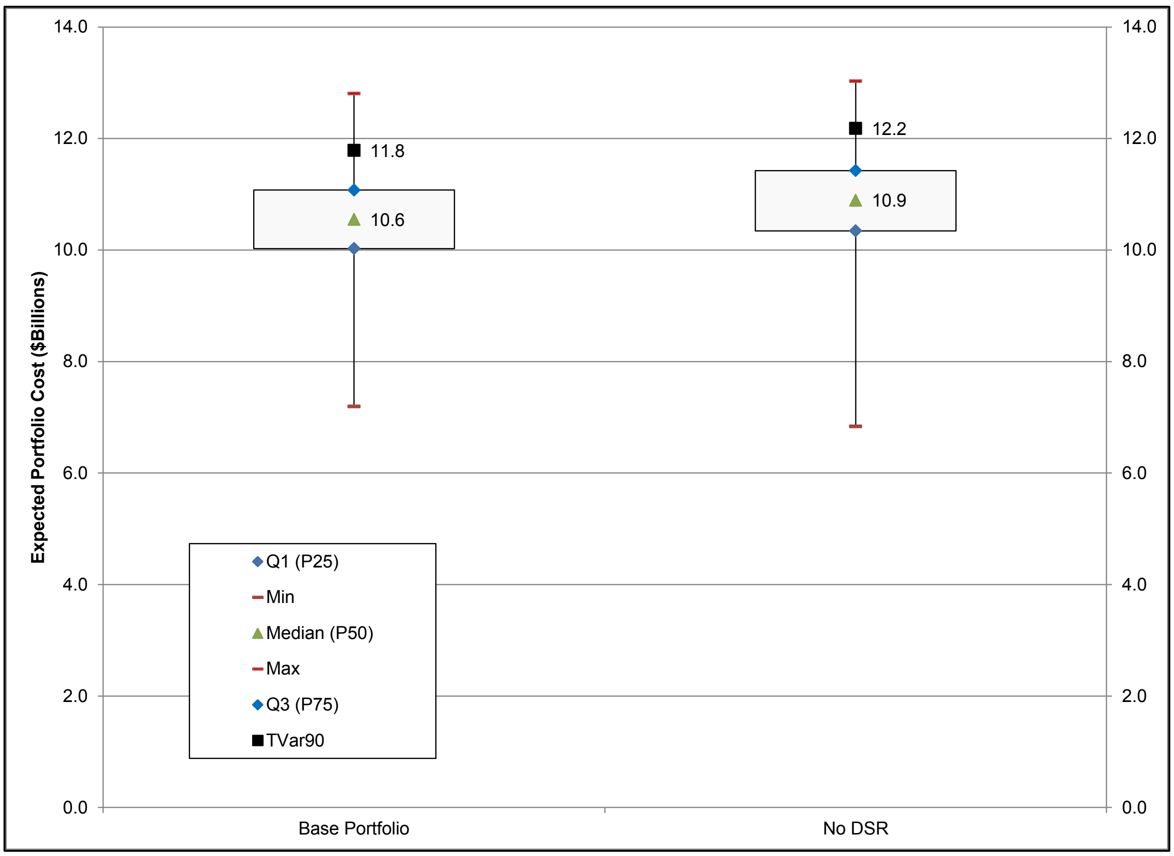


Figure 6-41 shows that DSR reduces power cost risk relative to no DSR. The TailVar90 of variable costs for the No DSR portfolio would be a little over $297 million higher than the Base Scenario optimal portfolio with DSR. It also illustrates that the No DSR portfolio revenue requirement is $555 billion more than the Base Scenario optimal portfolio, which reflects the higher costs of adding peakers instead of DSR. This is clearly a reasonable cost/risk tradeoff. Adding DSR to the portfolio reduces cost and risk at the same time.

Figure 6-41: Comparison of Expected Costs and Cost Ranges for No-DSR and Optimal Base Scenario Portfolios 20-yr NPV Portfolio Cost (dollars in billions)

No CO2 Price	Base + DSR	Base + No DSR	Difference
Expected Cost	11.98	12.54	0.56
TVar90	11.8	12.2	0.40

J. Extended DSR Potential

What if future DSR measures extend conservation periods through the second decade of the study period?

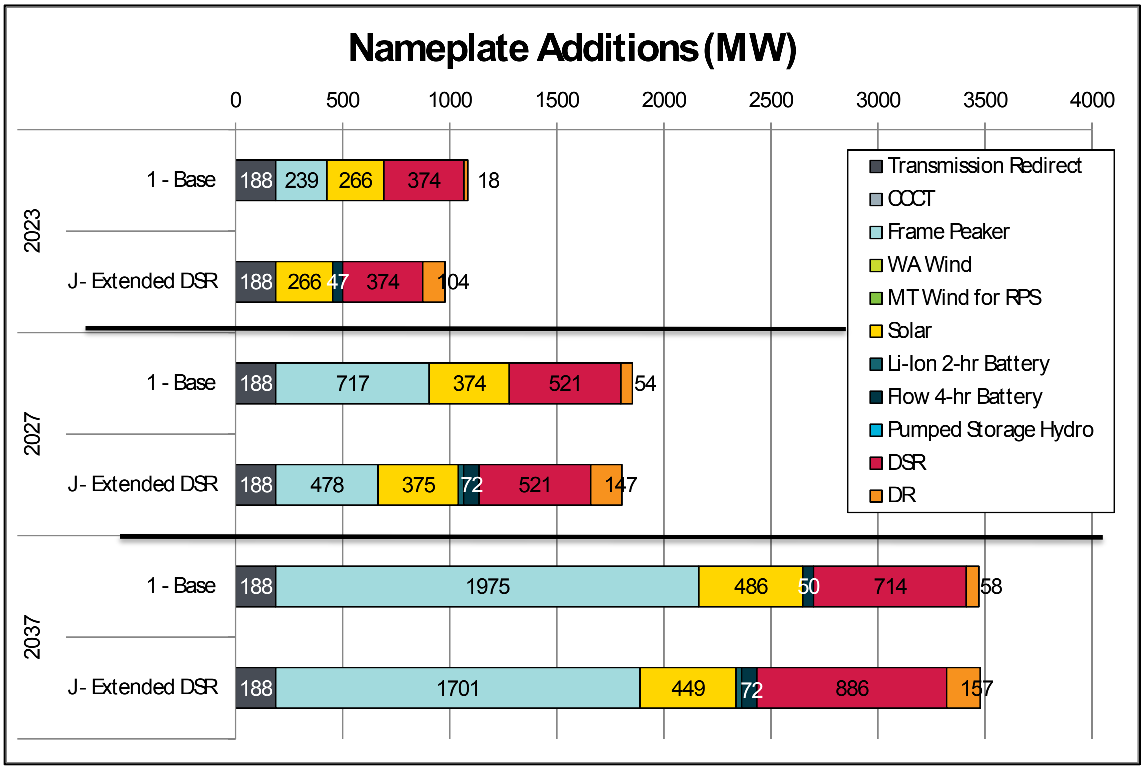
Baseline: All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.

Sensitivity: Assume future DSR measures will extend conservation benefits through the second 10 years of the study period.

The conservation potential in the IRP assumes a 10-year ramp-in of all existing conservation potential, and then the conservation potential drops off to just new builds after 10 years. This leads to a large increase in loads after 10 years. Assuming the same amount of conservation is attached for the full 20 years does not change the conservation bundle chosen; however, given the increase in conservation for the later years, we have one less peaker and more demand response. Given the higher amount of demand response, the battery is chosen in the early years and the frame peaker is not built until 2025. The expected portfolio cost is $11.89 billion, $87 million lower than the Base Scenario portfolio.

Figure 6-42 below compares the nameplate additions of resources for the Base Scenario portfolio with the extended DSR portfolio. By 2037, the Base Scenario portfolio has 772 MW of DSR, and the extended DSR portfolio has 886 MW of DSR.

Figure 6-42: Nameplate Additions, Extended DSR Sensitivity



K. Alternate Residential Conservation Discount Rate

How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation?

Baseline: Assume the base discount rate.

Sensitivity: Apply a societal discount rate to residential conservation savings.

An alternate discount rate was applied to the demand-side resource alternative in this sensitivity analysis (one that was lower than PSE's assigned WACC) to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was finalized as 1) the 3-month average of a long-term 30-year nominal treasury rate for residential customer class, and 2) the WACC discount rate for the commercial and industrial customer classes. The treasury rate used for developing the residential bundles was 2.94 percent. The impact was to shift measures to lower cost points on the conservation supply curve.

This alternate discount rate was used to estimate the DSR achievable potential for the new residential portion of the DSR bundles. These "alternate discount rate" bundles were then input into the portfolio model to obtain the cost-effective level of DSR.

KEY FINDINGS. Changing the discount rate for residential energy efficiency does not have a material impact on the cost-effective bundle of conservation in terms of peak capacity reduction. Changing the discount rate does change the mix of individual measures that make up the bundles. When the measures are reshuffled in this way, by 2037 the cost-effective peak capacity savings is slightly lower (by 21 MW), which is approximately a 3 percent reduction. The cumulative annual energy savings also decreases slightly, by 4 percent (17 aMW). It is possible that creating a new bundle (between Bundles 2 and 3) could show a slightly higher level of conservation, but given that this sensitivity analysis shows an immaterial impact, additional analysis is not warranted.

As shown in Figure 6-43, the electric conservation potential is pushed into lower cost bundles. However, now that the lower cost bundles have a higher level of DSR, this sensitivity is choosing Bundle 2 with a similar amount of DSR as Bundle 3 from the baseline.

Figure 6-43: DSR Potential

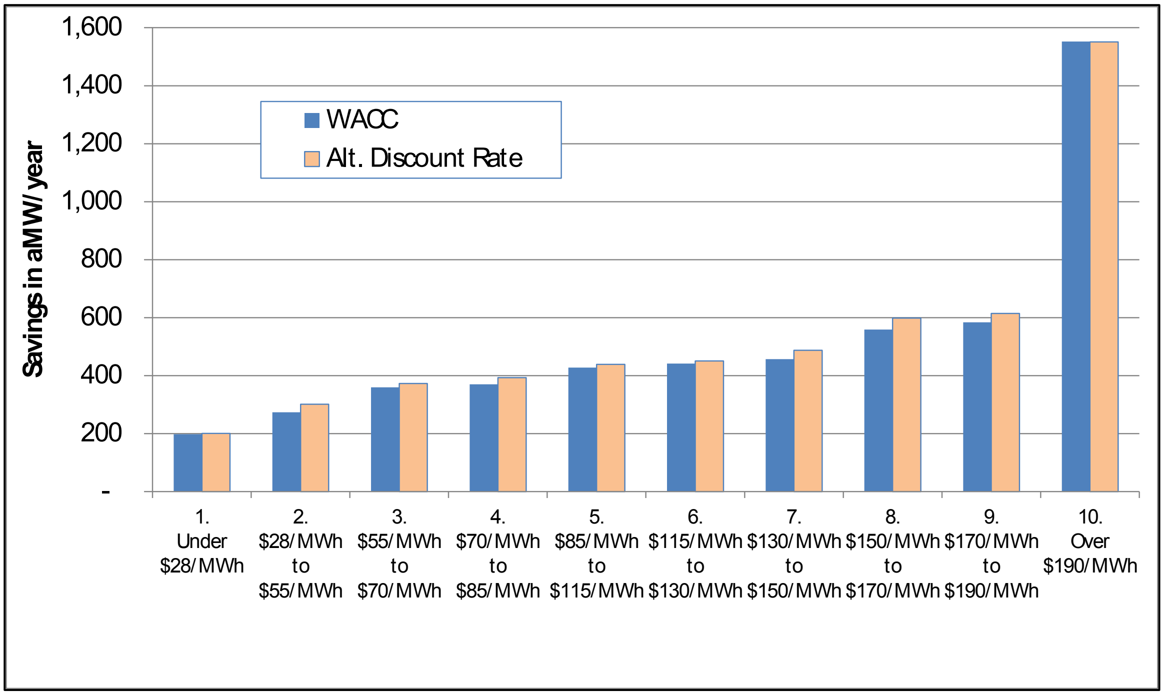
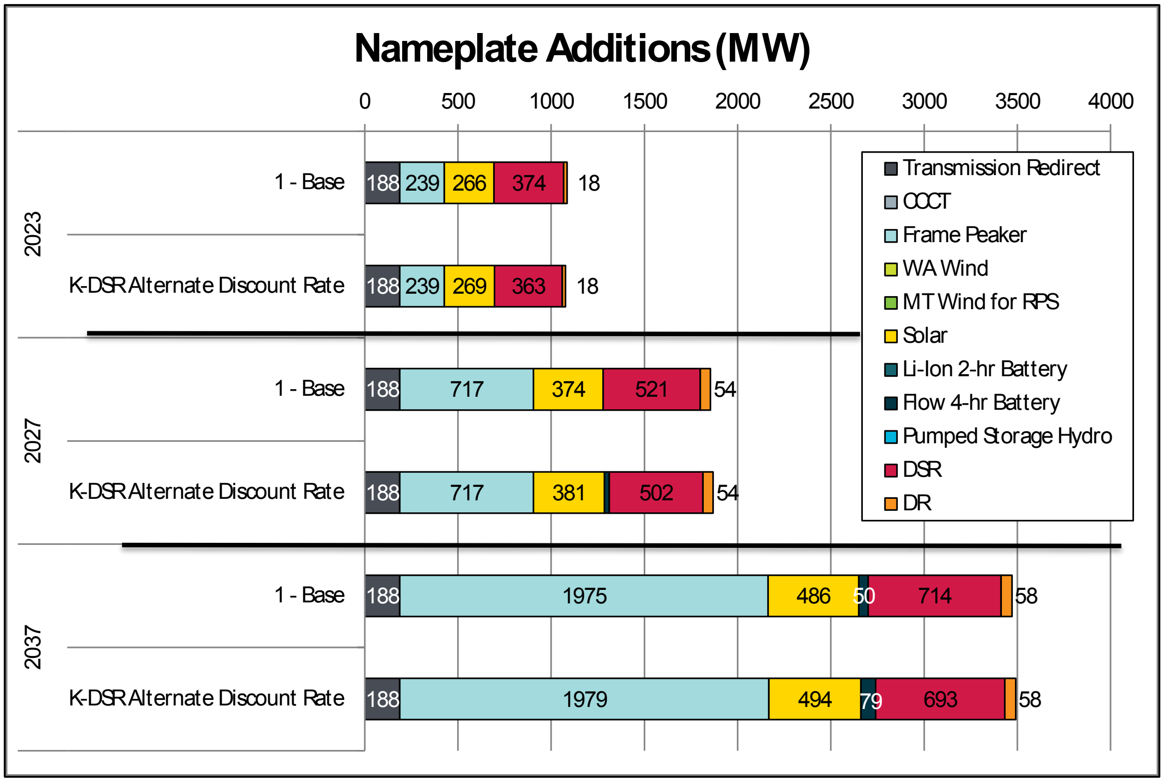


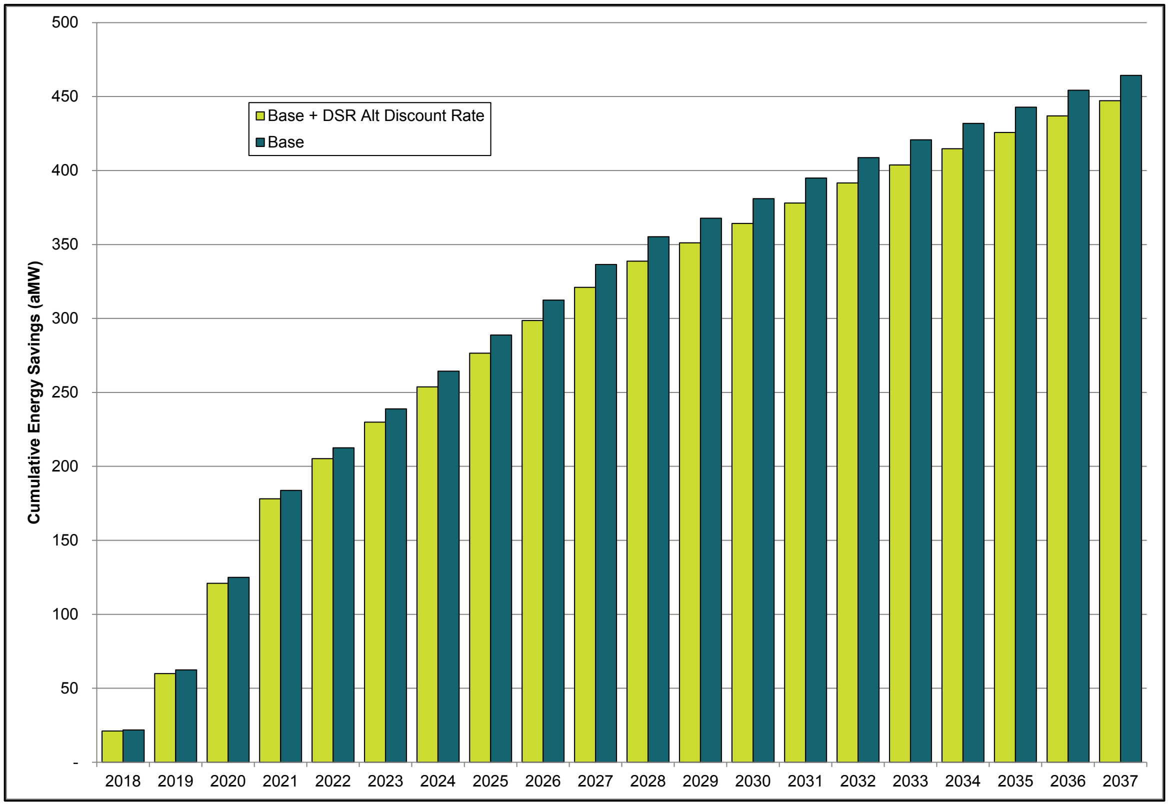
Figure 6-44 below compares the nameplate additions of resources for both Base Scenario portfolio DSR discount rate and the alternate discount rate. The Base Scenario portfolio has 772 MW of DSR, and the alternate discount rate portfolio has 693 MW of DSR.

Figure 6-64: Nameplate Additions, Alternate Residential Conservation Discount Rate



The cumulative energy savings are down slightly, as a result of reshuffling measures into the cost bundles. Figure 6-45 shows a slight reduction in the cumulative energy savings over time. By 2037, the difference is 17 aMW, or about 4 percent.

Figure 6-45: Impact on Cumulative Energy Savings is Immaterial



L. RPS-eligible Montana Wind

What is the cost difference between a portfolio with and without Montana wind?

Baseline: RPS-eligible Montana wind included only if chosen economically.

Sensitivity 1: Montana wind included in 2022 instead of solar.

- **a. 300 MW in 2022**
- **b. 150 MW in 2022**
- **c. 175 MW in 2022**

Sensitivity 2: Add Montana wind that does not qualify as RPS resource.

Sensitivity 3: Montana wind tipping point analysis on RPS vs. non-RPS resources.

KEY FINDINGS. Montana wind does not appear to be a cost-effective resource, even if it were able to meet the requirements of a qualifying renewable resource under RCW 19.285. Although it is possible that a specific Montana wind resource could look cost effective in an RFP if it were a qualifying resource, the likelihood of achieving that designation is very small at this time. To qualify under current law, Montana wind must be delivered to Washington state on a real-time basis without shaping or storage, and this provision would require coordination across multiple non-Washington state jurisdictional transmission entities in a process that doesn't currently exist. This is probably not commercially viable process for a developer or PSE. The analysis may still be helpful in the event the law is changed.

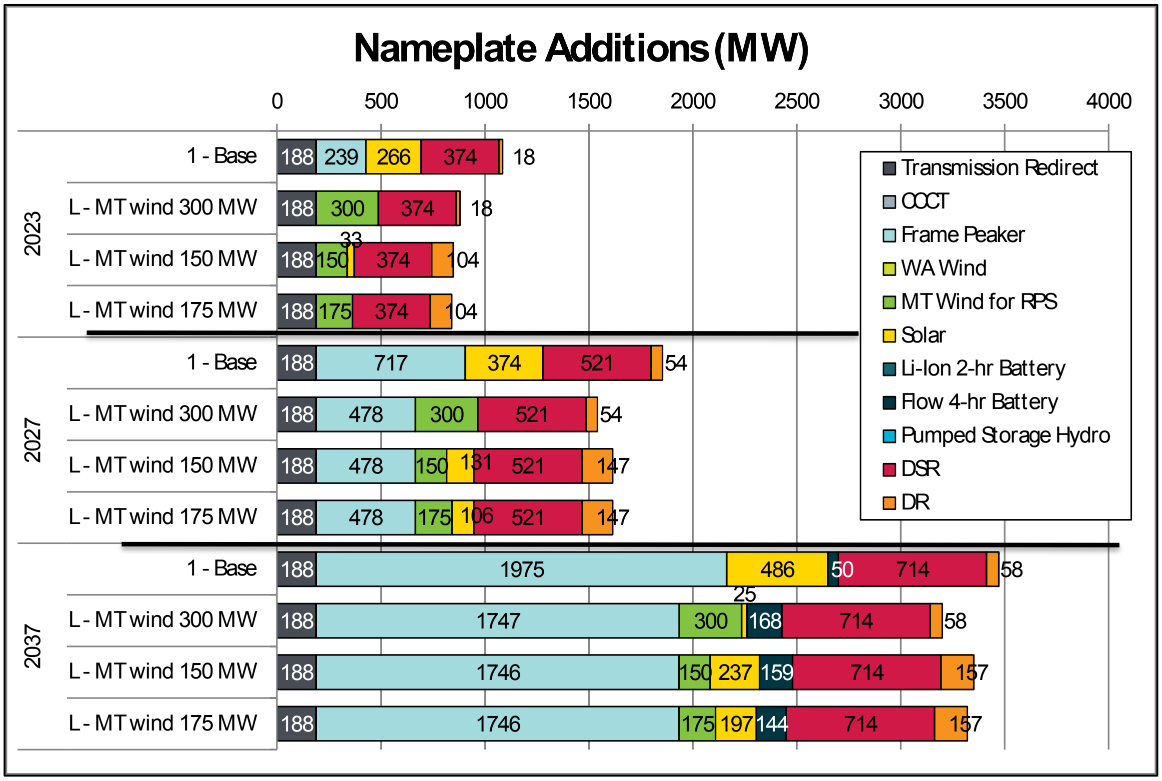
SUMMARY. Montana wind has the benefit of higher capacity factors than Washington wind (46 percent versus 30 percent), but it also requires added transmission costs to move the power to PSE's system. In addition, whether Montana wind qualifies as a qualifying renewable resource under RCW 19.285 depends on the location of the facility, and most of the prime wind resources in Montana are outside the footprint defined in the law. A complete discussion of the costs assumed for Montana wind can be found in Appendix D, Electric Analysis.

The first part of this sensitivity added 300 MW of Montana wind in 2022 instead of the economically chosen solar. Given the wind's higher capacity factor, this was enough energy to meet all of PSE's renewable needs for the next 20 years; however, adding Montana wind to the portfolio added $82 million to the total portfolio cost. Adding 300 MW of non-RPS qualified Montana wind would drive portfolio costs even higher. The portfolio would cost $12.24 billion, $257 million more than the Base Scenario portfolio and would only offset one frame peaker in 2022.

Instead of adding the full 300 MW of MT wind, we tested the assumption that PSE can share the resource with another company; allowing PSE to get a size that better fits our needs. We tested 150 MW (half a plant), but this not enough to meet the 2023 RPS needs, so solar is also added to make sure the portfolio is balanced. In order to meet the 2023 RPS needs, we need 175 MW of MT wind, so we also tested this size. Adding 150 MW of RPS-eligible Montana wind increased the portfolio cost by $35 million and adding 175 MW increased cost by $42 million

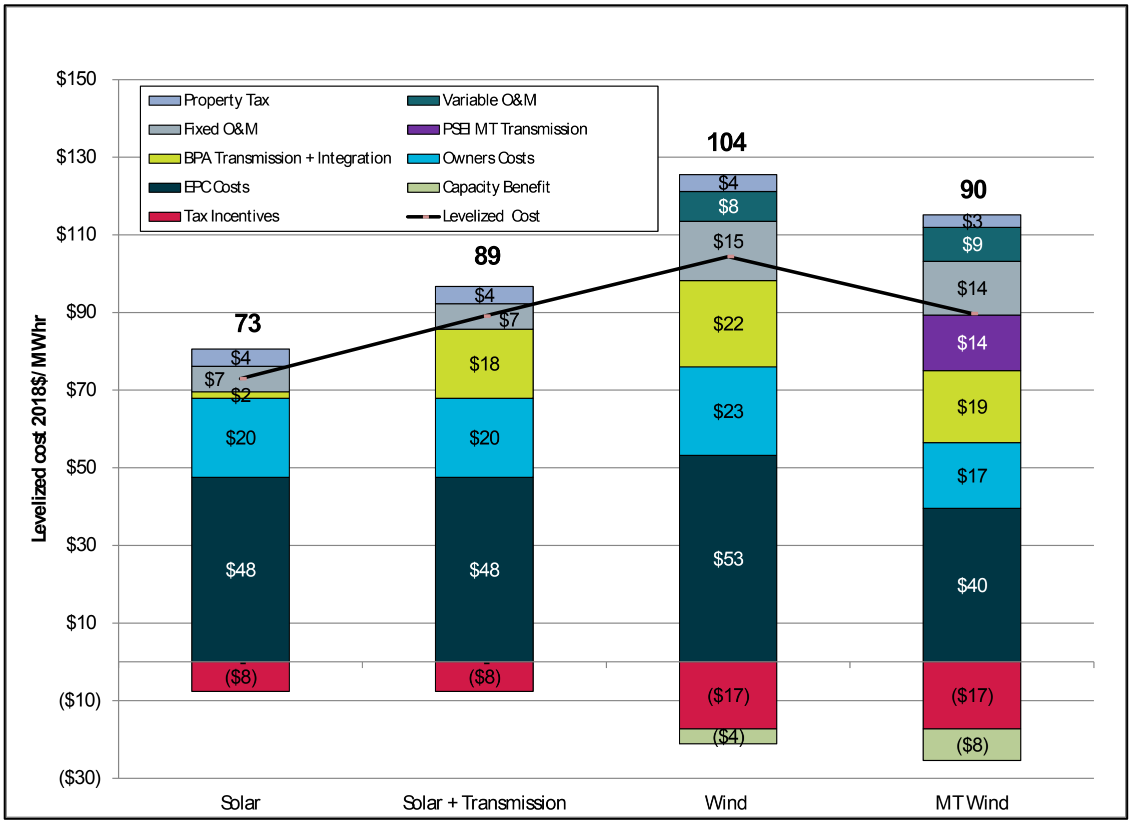
Figure 6-46 shows the total nameplate additions for the Base Scenario portfolio and a portfolio with Montana wind.

Figure 6-46: Nameplate Additions, RPS-eligible Montana Wind Sensitivity



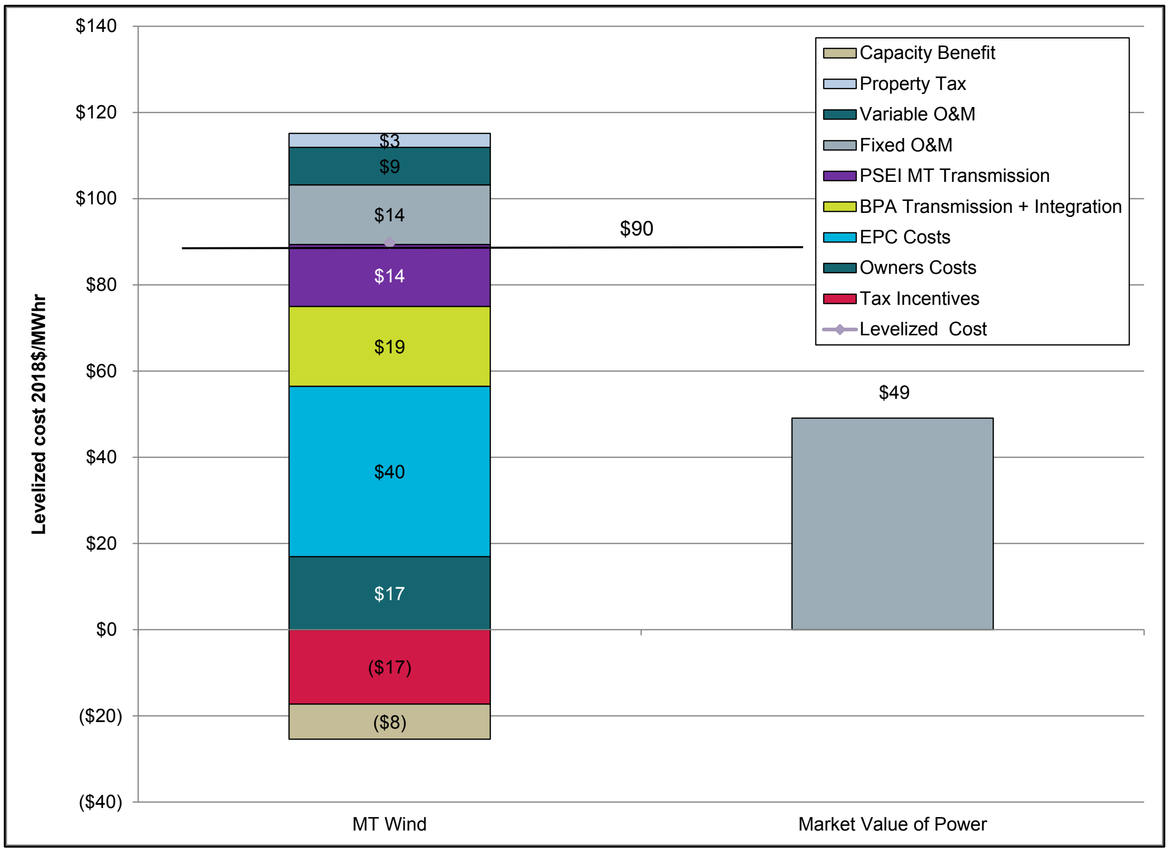
To be cost-competitive with solar resources at this time, the total cost of Montana wind would have to decrease by 16 percent. Figure 6-47 shows that Montana wind has a total levelized cost of $90/MWh, including the capacity value.

Figure 6-47: Wind and Solar Cost Components



If Montana wind is not a qualifying renewable resource, the cost reductions would have to be more significant. Figure 6-48 shows the same levelized cost of Montana wind as the prior chart – including the peak capacity value – but compared to wholesale market prices that do not include peak capacity value.

Figure 6-48: Wind and Solar Cost Components



M. Offshore Wind Tipping Point Analysis

How much would the cost of offshore wind need to drop in order for it to be a cost-competitive resource?

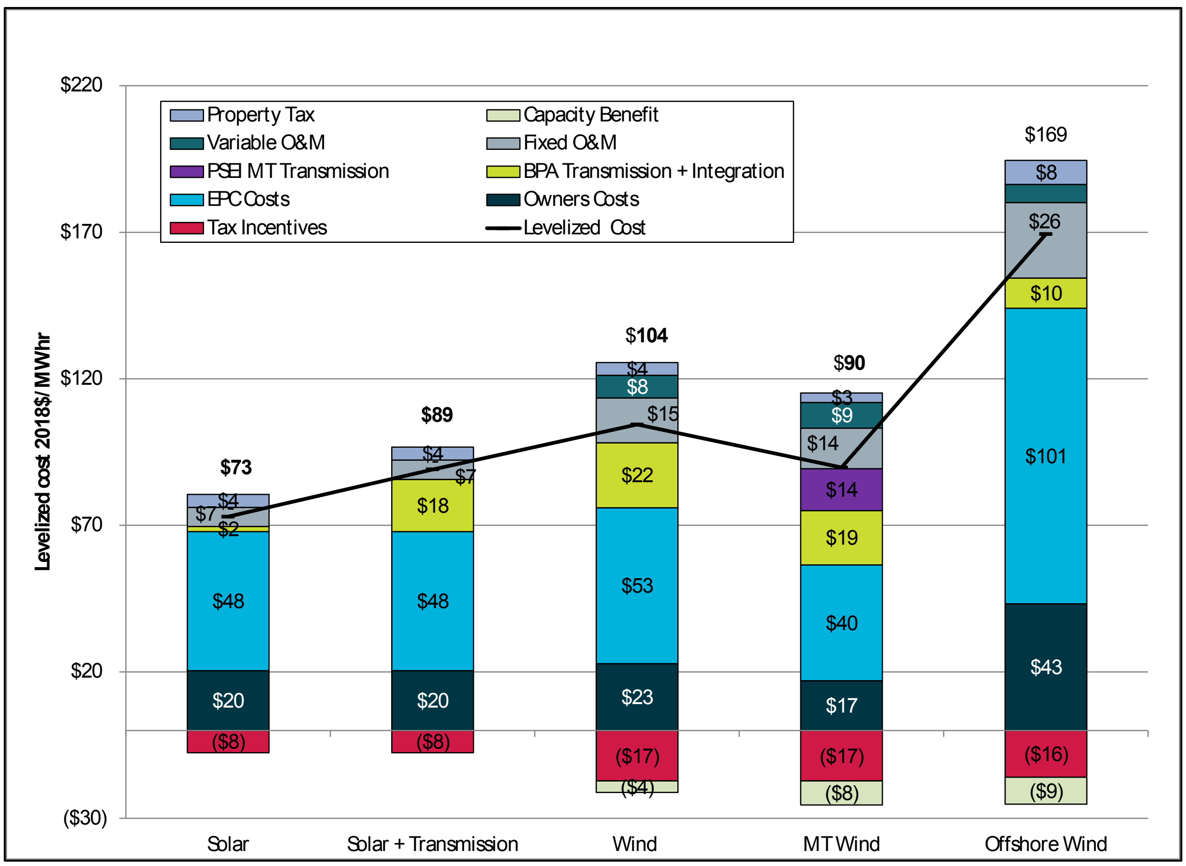
Baseline: Offshore wind not tested in the portfolio analysis.

Sensitivity: Offshore wind tipping point.

The current capital cost assumptions for wind from the DNV GL report on Washington state wind and solar costs is $5,500/kW EPC plus 30 percent owner's cost. The capital cost of offshore wind would have to drop by 73 percent, to $1,965/kw, including owner's costs, to be a cost-competitive resource.

Figure 6-49 below compares offshore wind costs to solar and onshore wind costs.

Figure 6-49: Offshore Wind Cost Components



N. Hopkins Ridge Repowering

Would repowering Hopkins Ridge for the tax incentives and bonus RECS be cost effective?

Baseline: Hopkins Ridge repowering is not included in the portfolio.

Sensitivity: Include Hopkins Ridge repowering in the portfolio to replace the current facility.

Repowering refers to the upgrade and renovation of an existing wind project to extend its generation life and possibly expand its production capability. The PATH Act of 2015 extends Production Tax Credits (PTCs) to repowered facilities. The economics of repowering are driven assuming the PTCs will offset the initial capital required.

KEY FINDINGS. Currently PSE is in tax loss situation where it has been unable to utilize the production tax benefit for a number of years. As a result, PSE has built a significant balance of unutilized PTCs over time. This analysis assumes the PTC can be utilized in the year of installation. The PTC rate is being phased down over time with the effective rate of 60 percent for 2018 construction start dates. To start construction any sooner than 2018 would lock PSE into a technology decision before the repowering decision was fully vetted. The results of the analysis indicate that it would add $40 million in costs to repower Hopkins Ridge. Based on these results, PSE would not move forward with the repowering of this wind facility.

Figure 6-50: Cost-Comparison, Hopkins Ridge Repowering Sensitivity

$ in Millions	Base Scenario	
	Portfolio Cost	Benefit/(Cost)
Base Scenario Portfolio	$11,981	
Repower Hopkins Ridge	$12,021	($40)
Repower Wild Horse	$12,023	($42)

8. COST OF CARBON ABATEMENT ANALYSIS RESULTS

This analysis focuses on investigating overall WECC-wide impacts of different policies aimed at carbon abatement. This perspective allows the overall effectiveness of such policies to be examined. Policies that affect the economic operation of carbon-emitting resources in one part of the WECC can affect neighboring areas through adjusted interchange transactions. In other words, disincentivizing carbon emissions in one region can make imports from regions without carbon abatement policies more attractive. Eleven alternatives were analyzed.

Figure 6-51: Carbon Abatement Alternatives Analyzed

COST OF CARBON ABATEMENT ALTERNATIVES ANALYZED		
	PSE Portfolio Alternatives	
A	**Additional Wind**	Add 300 MW of wind beyond RPS requirements.
B	**Additional Utility-scale Solar**	Add 300 MW of utility-scale solar beyond RPS requirements.
C	**Additional Electric Conservation – Incremental**	Increase conservation by 2 bundles relative to least-cost portfolio.
D	**Additional Electric Conservation – All**	Increase conservation to incorporate the entire conservation potential assessment available at any cost.
E	**Cost-effective Electric DSR**	Impact of acquiring all cost-effective electric conservation.
	Policy Alternatives	
F	**50% RPS in Washington**	Increase Washington RPS to 50% by 2040.
G	**CAR Cap on Washington CCCT plants**	Reduce the emissions of the CCCT plants in Washington to comply with the Washington Clean Air Rule CO2 emission baseline.
H	**Early Colstrip 3 & 4 Retirement**	Retire Colstrip 3 & 4 in 2025, rather than 2035, replacing it with the least-cost resources.
	Gas Utility Alternatives	
I	**Additional Gas Conservation – Incremental**	Increase conservation by 2 bundles relative to least-cost portfolio.
J	**Additional Gas Conservation – All**	Increase conservation to incorporate the entire conservation potential assessment available at any cost.
K	**Cost-effective Gas DSR**	Impact of acquiring all cost-effective gas conservation.

Methodology

The purpose of this analysis is to estimate the amount of carbon reductions possible from different alternatives and to estimate the cost per ton for those reductions. This allows us to create a carbon abatement supply curve, with total tons on the horizontal axis and annualized costs per ton on the vertical axis, as shown in Figure 6-52.

The alternatives examined can be grouped into three categories: changes to PSE's electric portfolio, larger policy changes in Washington state, and natural gas utility related alternatives. The same basic methodology was used to calculate the tons and costs per ton across all alternatives, though the tools and modeling methods needed to be different for the different categories.

ANNUALIZED COST. The cost for each abatement alternative was estimated by starting with the least cost portfolio in the Base + No CO_2 Scenario. This scenario was chosen to avoid biasing the analysis with policy changes, since some policy changes are examined. We implemented the abatement alternative, then examined the impact on cost to PSE's portfolio and the estimated emission reduction. The cost in dollars is the levelized, net present value of the annual cost impacts for 20 years. Portfolio costs were estimated using PSM III for electric alternatives and SENDOUT for natural gas utility alternatives.

ANNUALIZED TONS. Annualized tons is the levelized net present value of the annual emission reductions over 20 years for each alternative; in other words, it represents the average emission reductions on a per ton basis over the planning horizon.

COST PER TON. Using the levelized cost divided by levelized tons provides a reasonable estimate given that the timing of costs incurred and/or tons reduced are changing over time.

For electric portfolio alternatives, we used the AURORA model to estimate how the alternative would affect the dispatch of resources across the entire WECC. For example, in the Additional Utility-scale Solar Alternative, we added 300 MW of solar in eastern Washington, then re-dispatched resources across the entire WECC and calculated the change in emissions. This allows us to estimate the annual change in emissions from across the WECC, since adding solar in Washington can have impacts across the western U.S.

For the larger policy-related alternatives, estimating the cost per ton is more complicated. Our portfolio model is designed to estimate the costs to PSE's portfolio, not other investor-owned utilities or publicly owned utilities. That is, we can use AURORA to estimate the total impact on carbon emissions of a 50 percent RPS, but that analysis does not provide the cost. To address this, we estimated the cost per ton using PSE's costs as a proxy, as described below.

- 50 percent RPS: We used PSM III to build the optimal portfolio to meet the 50 percent RPS targets. This provided the annual portfolio costs and the schedule of resource builds. We then input the schedule of builds into AURORA and re-dispatched the entire WECC with those resources. Then we levelized the annual costs from PSM and levelized the annual carbon reductions from the WECC-wide AURORA analysis. We divided the levelized cost by the levelized tons as the estimate for the cost per ton. Estimating the total tons depicted on the horizontal axis in Figure 6-52 was more straightforward. We increased the Washington state RPS in AURORA and calculated the emission reductions compared to the Base + No CO_2 Scenario. Thus, the vertical axis in Figure 6-52 represents PSE's annualized cost per ton if we complied with a 50 percent RPS, and the horizontal axis depicts the total tons of carbon reductions assuming the policy is applied to all utilities in Washington.

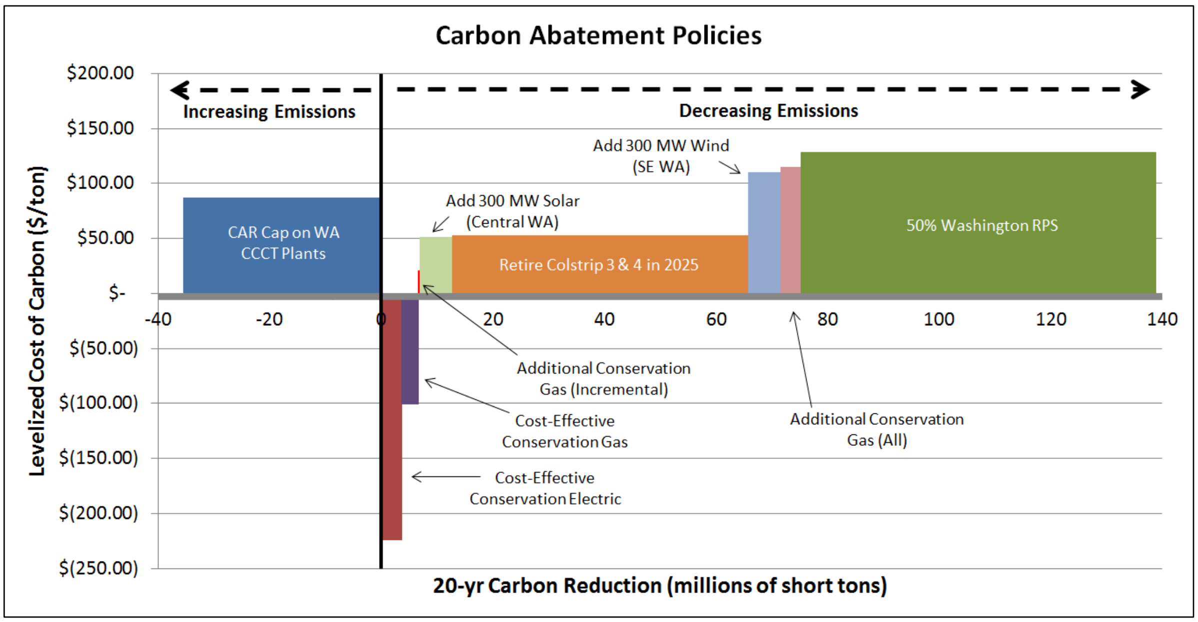
- CAR Cap on Washington CCCT Plants: Similar to the 50 percent RPS, we estimated PSE's cost per ton for the vertical axis of Figure 6-52; then on the horizontal axis, we used the summation of capping all CCCT plant dispatch to estimate the impact on total tons if the policy was applied to all CCCT plants in the state.

- Colstrip 3 & 4 Early Retirement: This alternative is in the larger policy category, because PSE is only part-owner of Colstrip 3 & 4, and PSE alone does not have the ability to retire the plant. To calculate the cost per ton, we used the portfolio analysis presented in the Colstrip Early Retirement Alternative in the Base + No CO_2 Scenario for the annual revenue requirement impact. Then we ran AURORA in the Base + No CO_2 Scenario for the entire WECC, to estimate the emission reduction from retiring Colstrip 3 & 4 in 2025. PSE owns 25 percent of Colstrip, so we took 25 percent of the emission reductions and levelized them to calculate the cost per ton. The vertical axis in Figure 6-52 represents an estimate of PSE's cost per ton; the horizontal axis represents the impact of retiring the entire plant in total tons.

For the natural gas utility alternatives, dollars per ton were estimated directly, based on the volume of gas conserved (or not) for each alternative.

Figure 6-54 below lines up the emission reduction alternatives into a carbon abatement curve. The alternatives to the left of the line increase emissions in the WECC and the policies to the right of the line decrease emissions in the WECC. The the vertical axis represents the levelized annual cost per ton of the CO_2 emission reductions, and the horizontal axis represents the summation of the total emissions reduction resulting from each alternative. The alternatives are lined up from least costly to most costly.

Figure 6-52: Carbon Abatement Curve
(Total tons reflects total WECC impact.)



Key Findings

Eleven alternatives were investigated in the Base + No CO_2 Scenario.

In the case of Alternative G, which models the CAR cap on Washington CCCT plants, CCCTs in Washington are emissions-limited, which increases reliance on new and existing peakers, and increases dispatch of less efficient CCCT plants and existing coal resources in WECC. This illustrates that CAR caps on CCCT plants increase carbon emissions when examined on a total WECC-wide system basis, which is why the data point is a negative abatement on the horizontal axis.

Two alternatives reduce carbon with a negative cost per ton: Alternative E and Alternative K. These are the Cost-effective Electric Conservation and and the Cost-effective Gas Conservation alternatives. "Cost-effective" conservation means it saves money and reduces carbon.

For Alternative C, Additional Electric Conservation – Incremental, a very small increase in carbon emissions is observed coincident with a small decrease in net load. The small increase in CO_2 emission is caused by the economic shift in resources. In this case, the small decrease in load was enough to run the coal plants plus peakers to meet the peaks instead of cycling down the coal plants and running CCCT plants to meet loads and peaks in the reference case. However, the observed increase in carbon emissions is relatively low, and this could be statistical noise or a modeling artifact. Therefore, we chose not to include this in Figure 6-52.

Alternative A, Additional Wind, and Alternative B, Additional Utility-scale Solar, reduce carbon emissions by reducing net demand in the system through injections of wind or solar power, respectively, into Washington. The reductions in carbon emissions observed in these two cases are from the least efficient resources available: existing coal and older gas plant dispatch.

Alternative F, 50 percent RPS in Washington, would have a relatively large reduction in emissions, but it is also a relatively high-cost alternative. In reality, there would be operational issues, including transmission capacity, that could increase the costs even more. The 50 percent RPS in Washington alternative reduces emissions in the WECC by increasing the non-carbon emitting resources, and thereby reducing demand for coal and existing CCCT.

Alternative H, the early Colstrip 3 & 4 retirement shows the cost per ton is about equivalent to adding 300 MW of solar, but the potential carbon savings is significantly greater. As mentioned above, this is not simply the carbon savings from retiring Colstrip in 2025, it reflects the fact that other resources need to be ramped up; that is, these results are net of leakage.

Alternative D, Electric Conservation – All, would produce a relatively large reduction in carbon emissions, but at a very high cost. The cost is so high that we chose not to include it on this chart, as it is not realistic and would make it difficult to see differences in some of the other alternatives on the chart.

Carbon abatement through gas conservation was investigated in Alternatives, I, J and K, and all were found to reduce emissions. The incremental conservation that was investigated in Alternative I had a negligible impact on emissions, while pursuing the entire gas conservation potential in Alternative J, Additional Gas Conservation – All, was found to be relatively high cost, but slightly less costly than the 50 percent RPS alternative.

Figure 6-53 below is a table of the total portfolio costs (in millions), regional emissions (in tons of CO_2) and the dollars per ton cost for the emission reduction.

Figure 6-53: Emission Reduction Costs for 9 Electric Portfolios

	Deterministic Portfolio Cost (Levelized Millions $)	Difference from Base (Millions $)	Regional Emissions (Levelized Millions Tons)	Difference from Base (Millions Tons)	Cost of Carbon Reduction ($/ton)
1 – Base + No CO2 Scenario	1,025		334.91		
A – Additional Wind	1,050	25	334.68	(0.23)	110.56
B – Additional Utility-scale Solar	1,037	12	334.67	(0.23)	50.66
C – Additional Electric Conservation – Incremental	1,048	23	334.96	0.05	(450.53)
D – Additional Electric Conservation – All	2,683	1,658	332.53	(2.38)	697.72
E – Cost-effective Electric DSR	1,082	57	335.16	(0.25)	224.06
F – 50% RPS in Washington	1,090	65	334.40	(0.51)	128.29
G – CAR cap on Washington CCCT plants	1,063	120	335.34	0.43	(87.41)
H – Early Colstrip 3 & 4 Retirement	1,051	26	332.93	(1.98)	52.61

Figure 6-54: Emission Reduction Costs for 4 Gas Portfolios

	Deterministic Portfolio Cost (Levelized Millions $)	Difference from Base (Millions $)	Regional Emissions (Levelized Millions Tons)	Difference from Base (Millions Tons)	Cost of Carbon Reduction ($/ton)
2 – Base + No CO2 Scenario	5,599		59.77		
I – Additional Gas Conservation – Incremental	5,601	2	59.69	(0.08)	20.45
J – Additional Gas Conservation – All	5,768	169	58.30	(1.47)	114.83
K – Cost-effective Gas DSR	5,716	117	60.94	1.16	(100.17)

9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

With stochastic risk analysis, we test the robustness of different portfolios. In other words, we want to know how well the portfolio might perform under a range of different conditions. For this purpose, we take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 250 draws[11] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 regulations/prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed.

Eight different portfolios were tested in the stochastic portfolio analysis. Figure 6-55 below describes the eight different portfolios.

Figure 6-5: Portfolios Tested for Stochastic Analysis

Portfolios Tested for Stochastic Analysis		
1	Base Scenario Portfolio	This is the optimal portfolio for the Base Scenario. It includes frame peakers for capacity and solar for the RPS.
2	Base + No CO2 portfolio	This is the optimal portfolio for the Base + No CO2 scenario. It includes CCCT for capacity and solar for the RPS.
3	No DSR	This portfolio is from the no DSR sensitivity.
4	Add 300 MW Utility Scale Solar	This portfolio is from the carbon abatement analysis.
5	No Transmission Redirect	Remove the transmission redirect as an option in the Base Scenario portfolio.
6	No New Thermal	This portfolio is from the no new thermal sensitivity.
7	Additional Electric Conservation – Incremental	Increase conservation by 2 bundles relative to least-cost portfolio (from the carbon abatement analysis).
8	Resource Plan	Batteries plus more DR in 2023, and solar moved to 2022.

One must approach results of this analysis carefully. This approach holds portfolios constant across the 14 different scenarios. In reality, PSE will not blindly follow any one of these resource

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

plan forecasts in the future – resource acquisitions will be made based on the latest information. In a resource acquisition, PSE and our customers would be locking into a decision that will be with us for a long time into an uncertain future. Additionally, the approach of measuring risk across a long planning horizon is not illustrative of annual risk profiles. Time is a hedge; that is, over 20 years, high-cost years will cancel out low-cost years, so risk is dampened by the long planning horizon. Looking at a one-year snapshot of risk may help. However, as different portfolios may have resources coming in during different years, a one-year snapshot may be misleading. Again, this is not a problem for a resource acquisition decision. Recall, one of the primary reasons for doing an IRP is to develop tools and frameworks to support making good resource acquisition decisions on behalf of our customers.

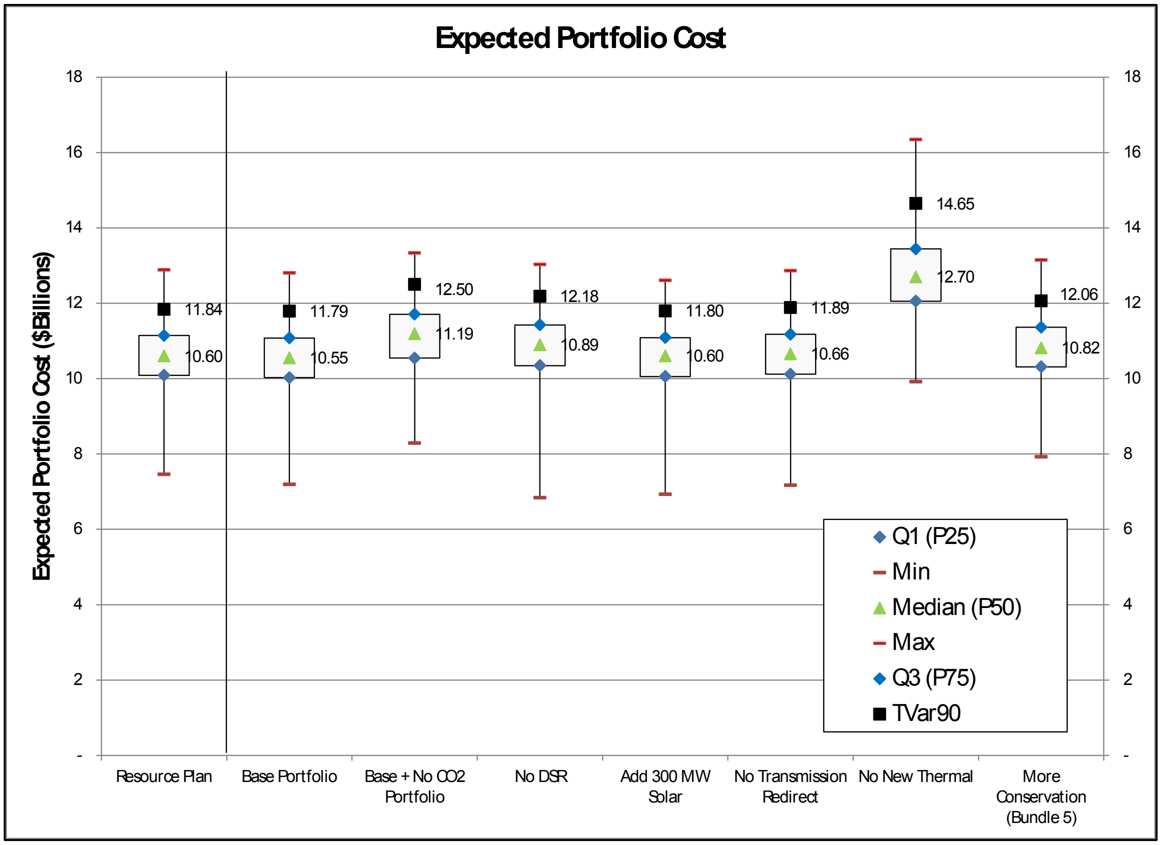
In Figure 6-56 below, the Base + No CO_2 portfolio includes baseload CCCT plants as the lowest cost resource, but since the stochastic analysis takes into account many different futures we see that the mean of the frame peaker portfolio is actually lower cost than the all-baseload gas portfolio.

Figure 6-56: Results of Stochastic Analysis

NPV ($Billions)	Mean	Difference from Base	% Change	TVar90	Difference from Base	% Change
1 – Base Scenario portfolio	10.52			11.79		
2 – Base + No CO2 portfolio	11.13	0.61	5.8%	12.50	0.71	6.0%
3 - No DSR	10.84	0.32	3.1%	12.18	0.40	3.4%
4 - Add 300 MW Utility Scale Solar	10.54	0.03	0.3%	11.80	0.01	0.1%
5 - No Transmission Redirect	10.62	0.10	0.9%	11.89	0.10	0.8%
6 - No New Thermal	12.69	2.18	20.7%	14.65	2.86	24.3%
7 - Additional Electric Conservation – Incremental	10.81	0.29	2.7%	12.06	0.27	2.3%
8 - Resource Plan	10.57	0.05	0.5%	11.84	0.05	0.4%

In this IRP, the lowest cost thermal resource varied between the frame peaker and the CCCT depending on the scenario. But the stochastic analysis indicates that frame peakers reduced the cost and risk of the portfolio. This is because the CO_2 regulations modeled targeted baseload thermal plants like CCCT and coal plants, not the peaker plants.

Figure 6-57: Range of Portfolio Costs across 1,000 Trials



In the Base Demand Forecast, the first large renewable build is in 2023. The Washington RPS increases to 15 percent in 2020, but with banking, we are able to push the first build to 2023. However the stochastic results in which the loads and wind generation are varied shows it is most likely there will not be enough RECs for 2022. So, PSE will need to move the 2023 build to 2022 to make sure we are in compliance with RCW 19.285.

Figure 6-58: Annual REC Surplus/(Need) for the Resource Plan Forecast (MWh RECs)