PUGET SOUND ENERGY

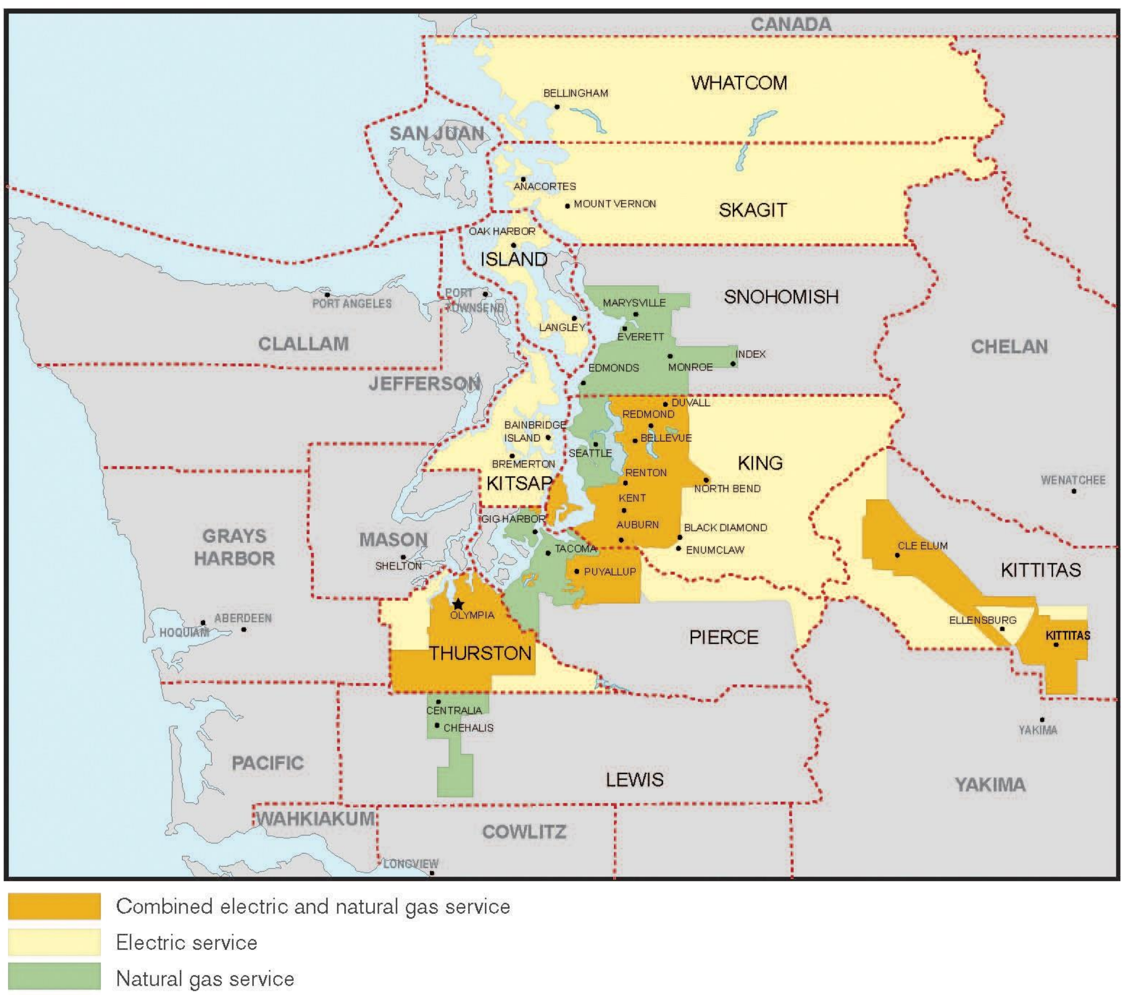
2015 Integrated Resource Plan

November 30, 2015

Chapters 1–7

ABOUT PSE

Puget Sound Energy is Washington State's oldest local energy company, providing electric and natural gas service to homes and businesses primarily in the vibrant Puget Sound area. With a service area that covers more than 6,000 square miles and stretches from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula, we serve more than 1.1 million electric customers and more than 790,000 natural gas customers in 10 counties.



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2015 PSE IRP EXECUTIVE SUMMARY

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The primary value of the IRP is what we learn from the opportunity to do three things: develop key analytical tools to aid in prudent decision making, create and manage expectations about the near future, and think broadly about the next two decades. The portfolios produced by the analysis are best understood as a forecast of resource additions that appear to be cost effective given what we know today about the future. We know these forecasts will change as the future unfolds and conditions change. PSE's commitments to action are driven by what we learn through the planning exercise. These commitments are embodied in the Action Plans presented here.

OVERVIEW

In this IRP, we reoriented our capacity planning standard to focus on the value of reliability to our customers; and, for the first time, we explicitly incorporated physical risk in wholesale markets into our needs assessment. This IRP indicates PSE needs to acquire approximately 275 MW of firm, dispatchable generation (most likely natural gas plants) in the next 7 years. This will be required to meet our customers' capacity needs as the regional capacity surplus – which PSE has relied on as a low cost/low risk resource – dwindles in the next few years.

On the gas side, PSE intends to begin construction of an LNG storage facility at the Port of Tacoma. This facility will serve two purposes. It will provide a cost-effective way to meet the peak needs of our gas customers, while also facilitating conversion of maritime vessels to natural gas fuel, reducing greenhouse gas emissions and reducing particulate emissions in the Puget Sound region.

Declining regional surpluses require a shift in electric resource strategy.

The surplus conditions the Pacific Northwest electric markets have experienced for a decade are forecast to change significantly with the scheduled retirement of two coal plants in 2020, Portland General Electric's 585 MW Boardman plant in Oregon and TransAlta's 730 MW Centralia Unit 1. According to studies of long-term resource adequacy from the region's energy organizations, regional market deficits are a possibility unless new resources are added in the region by 2021, and potential outages could affect more people and last longer than under previous conditions.[1]

This shift requires a change in PSE's electric resource strategy. During the decade of surplus capacity, relying on short-term wholesale market purchases to meet a significant portion of peak customer need has been a low cost/low risk strategy, but now that supplies are tightening, continuing this level of market purchases would expose PSE and its customers to unreasonable levels of physical and financial risk.

In this IRP, we directly incorporated physical wholesale market risk in the resource need analysis, so that risk is now reflected in the capacity planning standard.

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1 / The NPCC, PNUCC and BPA regional resource adequacy studies used in the preparation of this IRP analysis are available in Appendix F.

Updating the electric planning standard creates significant net benefits and risk mitigation for customers.

PSE's new electric planning standard is the optimal customer planning standard, because it is a product of a benefit/cost analysis that focuses on the cost to customers of potential outages (also known as the value of lost load). The former electric planning standard relied on an industry standard approach that targets a 5 percent loss of load probability (LOLP), which measures the likelihood of potential outage events rather than the magnitude of their impact on customers. Translating the MWh lost into the Customer Value of Lost Load allows us to quantify the value associated with different levels of reliability. Information from Figure 1-1, Comparison of Old and New Electric Capacity Planning Standards, shows that moving to the 2015 Optimal Planning Standard reduces the expected value of lost load to customers by $130 million per year.[2] The cost to achieve that expected savings is $63 million per year,[3] for a net benefit to customers of $67 million per year. Risk[4] reduction to customers is dramatic. That $67 million per year cost reduces the risk to customers by $1.3 billion per year.[5] Additional discussion is included in Chapter 2, Resource Plan Decisions, and Chapter 6, Electric Analysis.

Figure 1-1: Comparison of Old and New Electric Capacity Planning Standard

		Reliability Metric		2021 Capacity (Surplus)/ Need after DSR (MW)	Customer Value of Lost Load	
		LOLP	EUE (MWh)		Expected ($million/yr)	Risk- TailVar90 ($million/yr)
1	2013 Planning Standard with Market Risk	5%	50.0	(117)	169	1,691
2	2015 Optimal Customer Planning Standard (Includes Market Risk)	1%	10.9	234	39	385
	Change			351	(130)	(1,306)

2 / *From Figure 1-1. This is calculated by comparing the Expected Customer Value of Lost Load (VOLL) in line 1(2013 Planning Standard with Market Risk) with the Expected VOLL in line 2 (2015 Optimal Planning Standard): $169 million - $39 million = $130 million.*
3 / *This value is derived by first calculating the difference between the surplus of 117 MW in line 1 (2013 Planning Standard with Market Risk) and the need (deficit) of 234 MW in line 2 (2015 Optimal Planning Standard). This value is then multiplied by the levelized cost of a peaker, estimated from the portfolio model at $0.18 million per MW per year. So: 234 MW – (-117 MW) = 351 MW. Then: 351 MW * $0.18 million per MW per year = $63 million per year.*
4 /*Risk here is defined as TailVar90, which is the mean of the worst 10 percent of cases. It is a good risk metric, because it measures how bad conditions could be, in the event we find ourselves in extreme conditions. We use TailVar90 as the risk metric in both this planning standard analysis and the portfolio analysis.*
5 / / *$1,691 million (line 1) - $385 million (line 2) = $1,306 million.*

Gas pipelines that serve the region are reaching capacity with consequences for both electric and gas utility customers.

The region's natural gas markets are also experiencing a decline in surplus capacity as available pipeline capacity becomes more fully utilized. For decades, the Sumas market has been a reliable, liquid trading hub for PSE, but its supplies depend on the availability of upstream pipeline capacity to move gas from production areas to the market hub. In the past two years, one of the two major pipelines that interconnect at Sumas, the Westcoast Pipeline, has reached its peak design capacity limits.

GAS UTILITY IMPACTS

As a direct result of these conditions, PSE's gas utility has increased firm pipeline capacity commitments to cover 50 percent of the supplies we purchase at Sumas. Also, as pipeline capacity grows scarcer, storage capability may become increasingly important. In the future, PSE may need to take additional actions to ensure firm gas supplies are available at Sumas, even before considering the possibility that new, large gas consumers, such as methanol production or LNG export facilities, could increase demand for natural gas supplies in the region.

ELECTRIC UTILITY IMPACTS

The reliability of the electric system increasingly depends upon the reliability of the gas supply system, and gas-fired generation in the region will probably increase as coal plants are retired, so the dwindling surplus of pipeline capacity, especially at times of peak need, also has direct and indirect impacts on PSE's electric resource strategies.

- Electric reliability assessments will need to consider the availability of upstream pipeline capacity as well as direct-connect pipeline capacity, especially on pipelines we know are reaching capacity limits.
- The lack of verifiable firm gas supplies for the 650 MW Grays Harbor combined-cycle gas plant could significantly affect the amount of short-term wholesale power available for purchase by PSE and other regional utilities.

The convergence of natural gas and electric markets will continue to be an important reliability issue for both PSE and the region.

PSE continues to explore and evaluate emerging resources.

As part of PSE's ongoing commitment to the exploration and evaluation of emerging resources, this IRP includes new analyses of rooftop solar generation (distributed solar) and electric energy storage.

SOLAR

Moving beyond the question of whether distributed solar would be cost effective for the utility, we asked: What might we need to do if our customers want PSE to integrate significant amounts of distributed solar? Specifically, we examined the impact that high penetrations of rooftop solar would have on four distribution circuits, each of which serves a different kind of customer base. Also, with the help of the Cadmus Group, we analyzed the maximum amount of rooftop solar PV that could be installed in PSE's service territory. Finally, in a sensitivity analysis, we studied the impact to portfolio cost and emissions of adding 300 MW of distributed solar across the entire system by 2035.

ELECTRIC ENERGY STORAGE

Electric energy storage has made significant progress in recent years, and in this IRP we studied two storage technologies, batteries and pumped hydro. Batteries demonstrated significantly higher flexibility value than thermal resources when we analyzed them using our sub-hourly flexibility model. However, the relative values were not such that batteries appeared cost effective. To set up the next stage of battery analysis, we included a tipping point analysis in this study to identify what the flexibility value would need to be for batteries to be forecast as part of a least-cost portfolio.

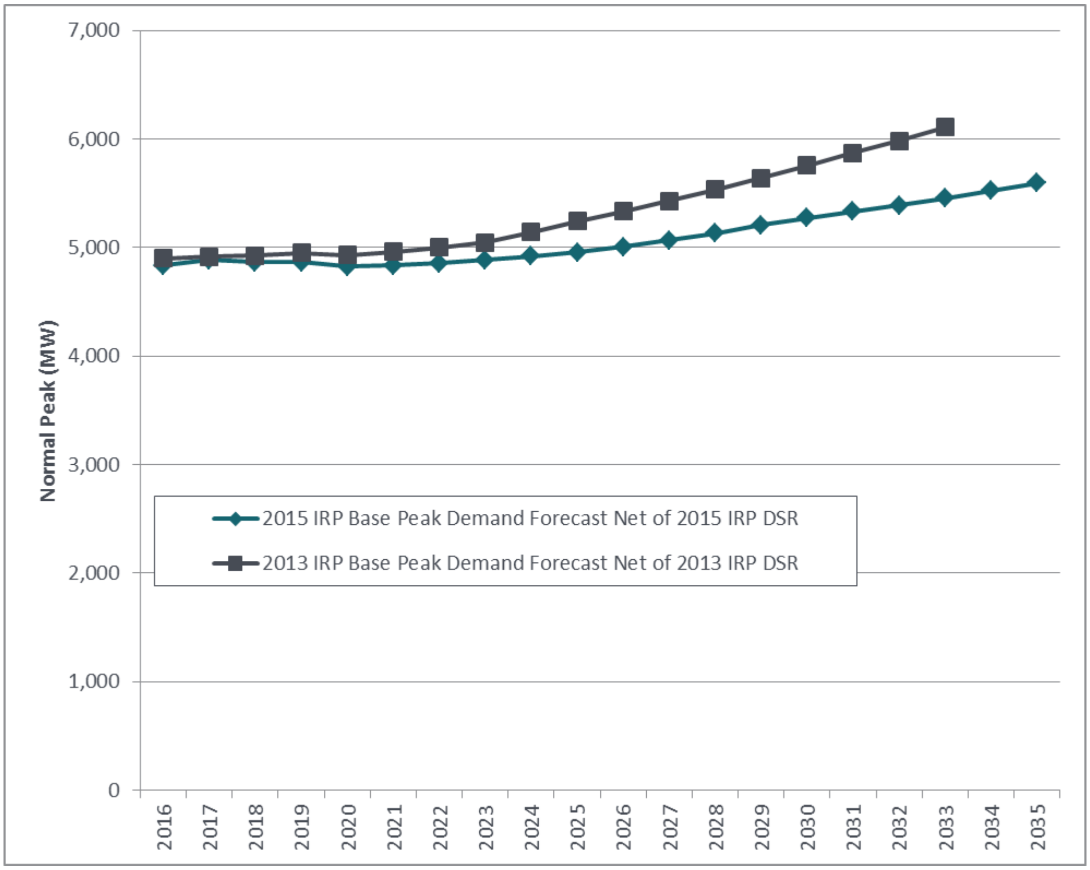
PSE will focus considerable efforts in the 2017 IRP cycle to improving our flexibility analysis and monitoring emerging resource opportunities, as noted in the Action Plans.

Overall, electric demand growth has slowed, but some areas are growing rapidly.

At the system level, demand growth has slowed significantly compared with the 2013 IRP Base Demand Forecast, but some areas continue to experience rapid growth – particularly the Eastside area of King County that includes downtown Bellevue.

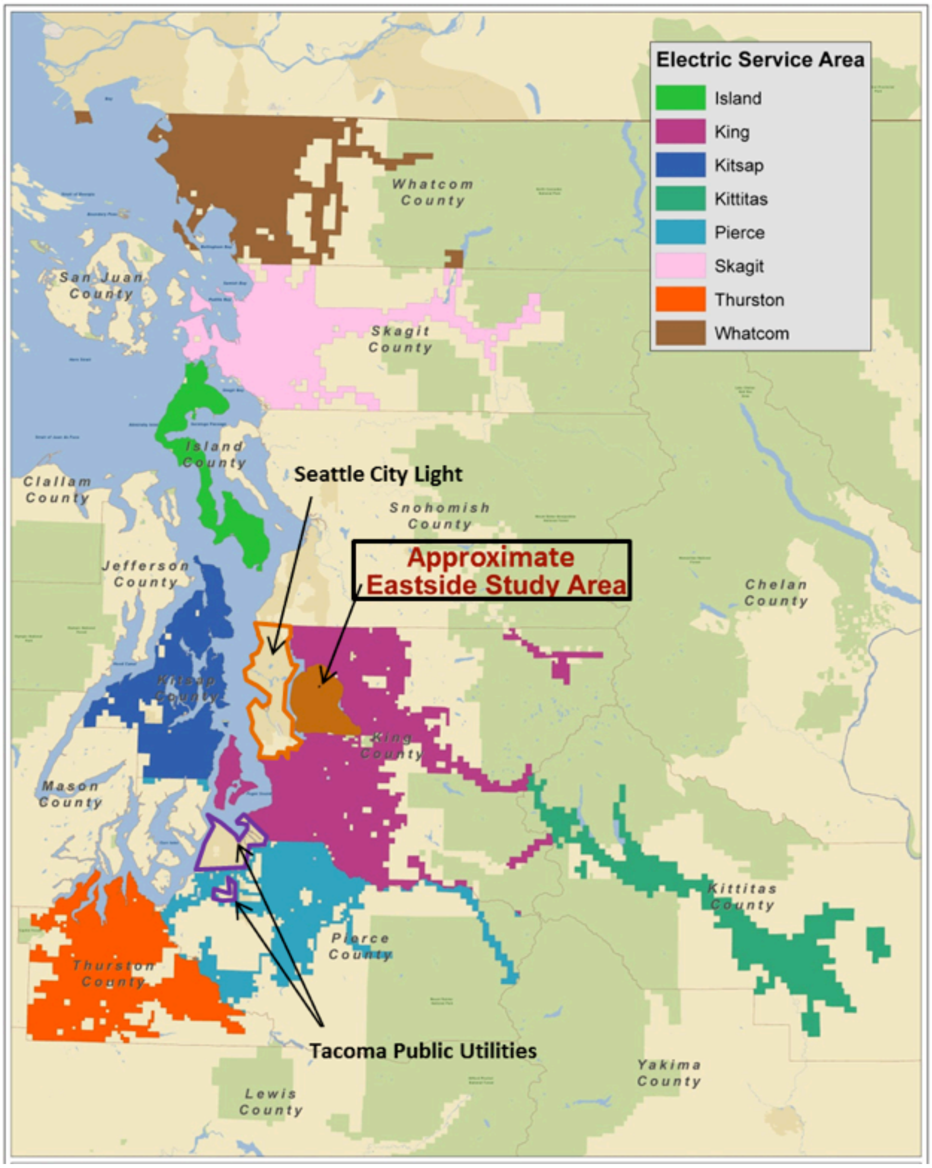
For the 2015 IRP Electric Base Peak Demand Forecast at the system level, the average annual expected growth rate for the 20-year study period has declined to 1.6 percent from 1.9 percent in the 2013 forecast. Similarly, the average annual growth rate for electric customer counts declined to 1.5 percent from 1.7 percent in the 2013 forecast. These declines are driven by a slower-than-expected recovery from the recession, lower population growth forecasts, and by significant updates to PSE's load forecasting models. These updates were developed in response to feedback from the WUTC in its acceptance letter for the 2013 IRP. Figure 1-2 shows the 2013 and 2015 IRP Base Peak Electric Demand Forecasts after conservation. Peak capacity need is significantly reduced in the outer years.

Figure 1-2: 2013 IRP Base Peak Electric Demand Forecast Net of 2013 IRP DSR and 2015 IRP Base Peak Electric Demand Forecast Net of 2015 IRP DSR



While overall, system-level growth after conservation will be quite low, the map and table in Figure 1-3, illustrate how unevenly population, employment, customers and sales are distributed across PSE's electric service territory. King County accounts for roughly half of the system's customer base and electric sales today and 58 percent of employment in the service territory.

Figure 1-3: Distribution of Population, Employment, Customers and Sales across PSE Electric Service Territory



County	Population	Employment	Customers	Sales
King	48%	58%	49%	52%
Thurston	10%	9%	11%	11%
Pierce	15%	10%	10%	9%
Kitsap	10%	8%	11%	9%
Whatcom	8%	8%	9%	9%
Skagit	5%	4%	5%	7%
Island	3%	1%	3%	2%
Kittitas	2%	1%	1%	1%
Eastside Area	9%	19%	10%	14%

Growth is concentrated in the Eastside area. The Eastside's average annual peak demand growth rate of about 2.5 percent from 2014 to 2031 is significantly higher than the 1.6 percent growth rate in the system-level forecast.

The IRP provides inputs to the local infrastructure planning process, including information on conservation and distributed resources; however, the planning process for addressing local distribution and transmission needs focuses on the specific engineering, siting, and permitting details of specific challenges, and is appropriately separate from the IRP's high-level generic resource and system-wide viewpoint.

ACTION PLANS

Action Plans vs. Resource Plan Forecasts

In recent years, the IRP has attracted more attention from policy makers, the public, and advocacy groups. Many tend to assume the resource plans produced by the IRP analysis are the plan that PSE intends to execute against. This is not the case. The resource plans are more accurately understood as forecasts of resource additions that look like they will be cost effective in the future, given what we know about the future today. What we learn from this forecasting exercise determines the Action Plan, and this is "the plan" that PSE will execute against.

The following discussion presents the Action Plans first, followed by the electric and gas sales resource plan forecasts.

Electric Action Plan

1. Acquire energy efficiency.
Develop 2-year targets and implement programs that will put us on a path to achieve an additional 411 MW of energy efficiency by 2021.

2. Acquire demand-response.
Develop and implement a demand-response acquisition process and issue a Request for Proposal (RFP). The analysis supports addition of demand-response by 2021, but these programs don't fit existing energy efficiency or supply-side resource models.

3. Supply-side resources: Clarify before issuing an all-source RFP.
Energy efficiency and demand-response additions appear sufficient to meet incremental capacity need until 2021 and additional renewables are not needed until 2023. PSE intends to issue an all-source RFP[6] in 2016, subject to an update to resource needs, most likely in early summer of 2016.[7] This postponement will provide time to incorporate an updated regional adequacy assessment into our resource need, which is scheduled to be completed by the NPCC in the second quarter of 2016.

6/ Chapter 3, Planning Environment, describes the resource acquisition process.
7/ In late August, 2015, the Northwest Power and Conservation Council (NPCC) signaled that draft results in its 7th Power Plan appear to contradict its May 2015 finding that the region needs to add approximately 1,150 MW of generation capacity by 2021 to avoid deficit conditions. Changes in the status of regional resource adequacy as a result of further study in 2016 may cause PSE to adjust the magnitude of its resource need, and we will continue to work with others in the region on this assessment.

There are indications from the NPCC that updates to some key assumptions from their draft 7th Power Plan may impact the regional adequacy. Therefore, it makes sense to further refine our resource needs before embarking on this costly and complicated process. The all-source RFP will include a process to aggregate smaller kinds of resources, such as distributed resources, combined heat and power, etc., along-side traditional utility-scale resources.

4. Improve analytical capabilities.

With this IRP, PSE made two major improvements to its analytical capabilities. We applied a benefit/cost analysis focused on the cost to customers of potential outages to update the electric planning standard, and we developed a framework for translating regional resource adequacy to its impact on PSE's electric system and customers. We also analyzed whether backup fuel for our existing peaking units is sufficient to meet reliability needs without firm pipeline capacity.

The next important area of focus will be intrahour flexibility for the electric portfolio. Analysis in this IRP demonstrated that initial estimates of intrahour flexibility values could significantly affect the least-cost mix of resources and possibly add reciprocating engines to the portfolio. Specifically, in the 2017 IRP planning cycle, we will:

- Define specific elements of intrahour flexibility that need to be valued and prioritize them according to their potential to impact future resource decisions.
- Refine existing or develop new analytical frameworks to estimate, from a portfolio perspective, the value that different types of resources can provide for each element of flexibility.
- Ensure that frameworks reasonably address energy storage technologies, including batteries, pumped hydro, kinetic storage and others.

5. Actively investigate emerging resources.

For batteries, continue to explore potential applications and demonstration projects; for solar, update market penetration studies and continue study of system planning implications; for electric powered vehicles, continue load research. Continue to explore the possibilities provided by new emerging resources.

6. Participate in the California Energy Imbalance Market (EIM).

PSE has committed to joining the California EIM. This market will allow PSE to purchase sub-hourly flexibility at 15- and 5-minute increments from other EIM participants to meet our flexibility needs when market prices are cheaper than using our own resources. This will also allow PSE the opportunity to sell flexibility to other EIM participants when we have surplus flexibility. The benefits of lower costs on the one hand and net revenue from EIM sales on the other will reduce power costs to our customers.

Gas Sales Action Plan

1. Acquire energy efficiency.

Develop 2-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting.

2. Develop the PSE LNG project.

Continue work to develop an LNG facility for serving both the peak needs of gas customers and the transportation markets at the Port of Tacoma.

3. Begin upgrades to Swarr.

Implement plans to ensure that the full upgraded capacity of the Swarr propane-air facility is available by the 2016/17 or 2017/18 heating season.

4. Improve analysis on basin risk.

Acquiring long-term pipeline capacity to one supply basin entails risk, as the relationship between gas prices in different supply basins is uncertain and changes over time. Resources that do not rely on making a long-term commitment to one supply basin reduce risk. Such resources may include conservation, on-system storage and market-area storage. These resources avoid placing a bet on which basin-plus-transportation cost will be lowest cost in the long run. PSE will refine its analysis of this risk, and work with other gas utilities on ways to improve its ability to analyze this issue, in the 2017 IRP.

Gas-Electric Convergence Action Plan

1. Non-firm gas supplies for PSE's portfolio.

Continue monitoring sufficiency of non-firm gas versus backup fuel as PSE begins operating in the California EIM; as regional natural gas demand grows; and as interstate pipelines become more fully utilized.

2. Non-firm gas supplies for regional adequacy.

Work with others in various industry forums on developing resource adequacy criteria for natural gas generating plants that do not have verifiable fuel supply.

ELECTRIC RESOURCE PLAN FORECAST

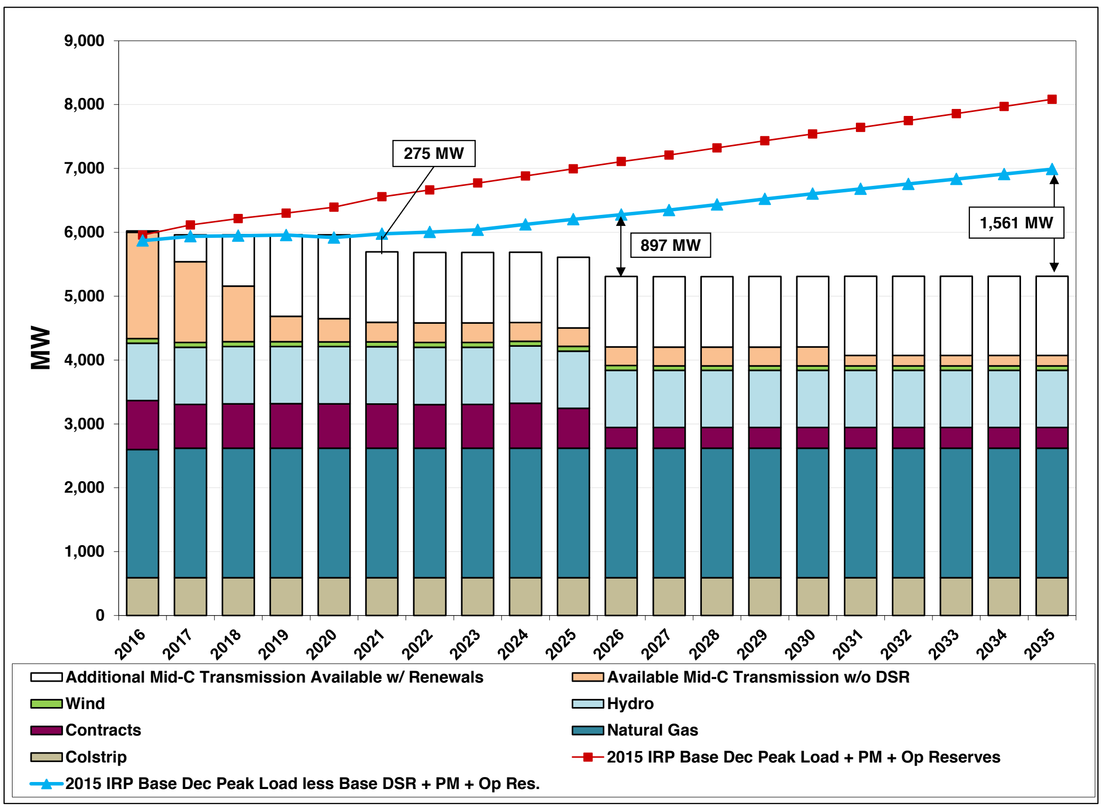
Electric Resource Need

PSE must meet the physical needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in terms of peak hour capacity and energy. Operating reserves are included in physical needs; these are required by contract with the Northwest Power Pool and by the North American Electric Reliability Corporation (NERC) to ensure total system reliability. In addition to meeting customers' physical needs, Washington state law (RCW 19.285) also requires utilities to acquire specified amounts of renewable resources or equivalent renewable energy credits (RECs). There are details in the law such that complying with RCW 19.285 may not directly correspond to meeting reliability needs, so this is expressed as a separate category of resource need.

- Figure 1-4 presents electric peak hour capacity need.
- Figure 1-5 presents the electric energy need (the annual energy position for the 2015 Base Scenario).
- Figure 1-6 presents PSE's renewable energy credit need.

Electric Peak Hour Capacity Need. Figure 1-4 compares the existing resources available to meet peak hour capacity[8] with the projected need over the planning horizon. The company's electric resource outlook in the Base Scenario indicates the initial need for an additional 275 MW of peak hour capacity by 2021.[9] This picture includes the resources required to meet peak hour customer demand events and the planning margin and operating reserves that must be maintained to achieve the 2015 Optimal Planning Standard. It also incorporates an adjustment to the peak capacity contribution of wholesale market purchases.[10] The important role demand-side resources play in moderating the need to add supply-side resources in the future can be seen in the peak load lines in Figure 1-4; the lower line includes the benefit of DSR while the upper line does not.

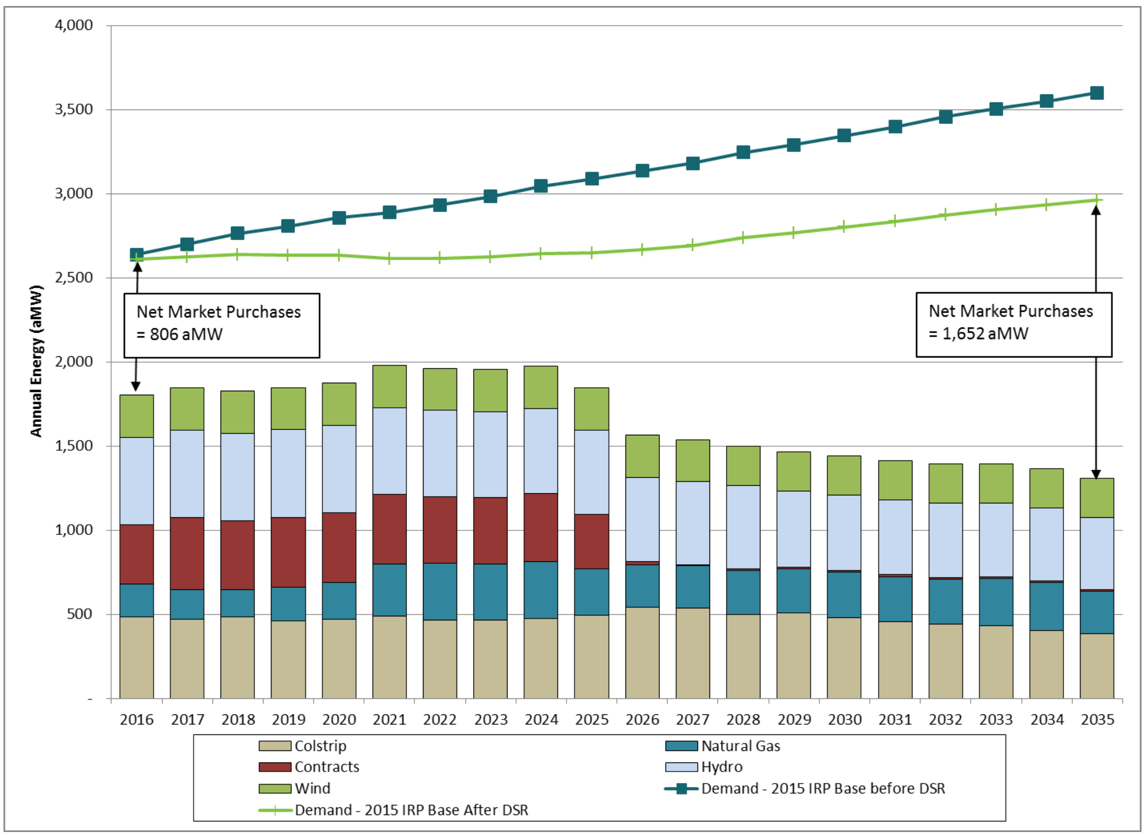
Figure 1-4: Electric Peak Hour Capacity Resource Need
(Projected peak hour need and effective capacity of existing resources)



8 / *Resource capacities illustrated here reflect the contribution to peak, not nameplate capacity, so PSE's approximate 823 MW of owned and contracted wind appear very small on this chart. Refer to Chapter 6, Electric Analysis, for how peak capacity contributions were assessed.*
9 / *The 275 MW in Figure 1-4 shows a small difference from the 234 MW shown above in Figure 1-1. This 41 MW difference is because the analysis to establish the planning standard shown in Figure 1-1 was based on estimated conservation, versus final 2015 IRP conservation savings that came in slightly lower, along with slight differences in applying operating reserves in the deterministic and stochastic analyses, and the transmission availability impact of carrying those reserves at Mid-C.*
10 / *Chapter 6, Electric Analysis, includes a description of electric planning standards.*

Electric Energy Need. Peak hour capacity is an important aspect of PSE's ability to adequately meet the physical needs of our customers. However, our customers require reliable, economic electric service during all hours. Figure 1-5 compares the company's annual forecast of energy sales to retail electric customers with expected generation for the year by resource type.[11] This "energy position" reflects the most economical dispatch of our electric resource portfolio based on expected market conditions; it is not a physical need. PSE could generate significantly more energy than needed to meet our load on a monthly or annual basis, but will purchase energy in the wholesale market when it is more cost effective than running our thermal resources. Load forecasts in this chart are aggregated to an annual basis.

Figure 1-5: Annual Energy Position for 2015 IRP Resource Plan in the Base Scenario

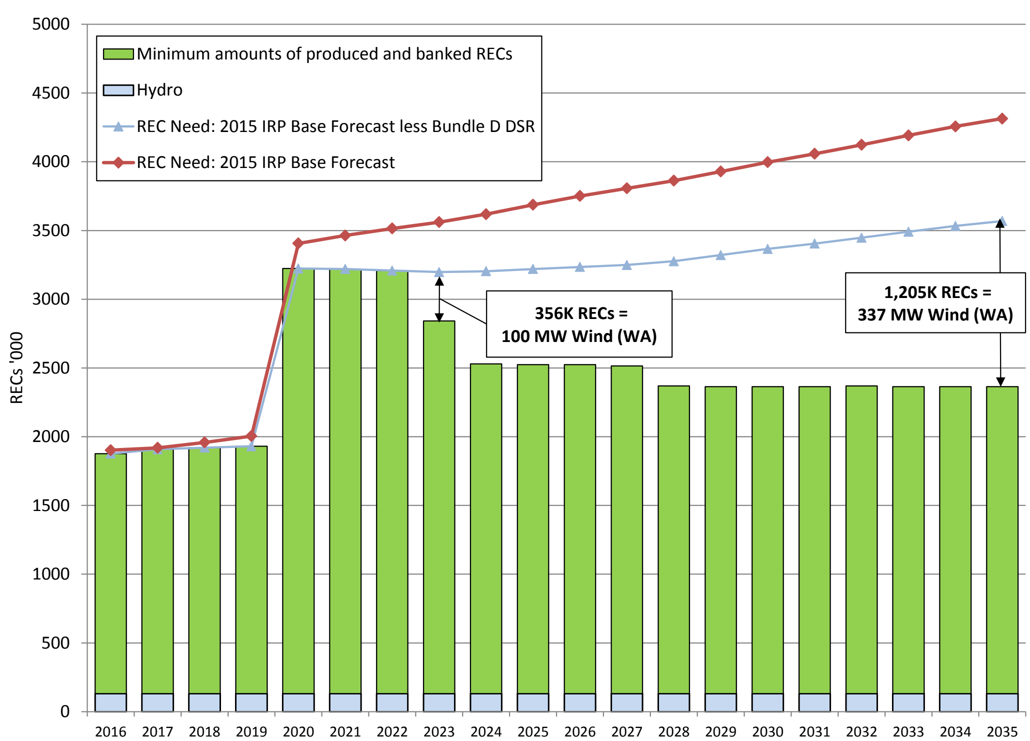


11 / Wind in this chart shows more prominently than in the capacity need chart, because this reflects the expected annual generation of wind, not just what can be relied upon to meet peak capacity needs.

Renewable Need. In addition to reliably meeting the physical needs of our customers, RCW 19.285 – the Washington State Energy Independence Act – establishes 3 specific targets for qualifying renewable energy. These are commonly referred to as the state's renewable portfolio standard. Sufficient "qualifying renewable energy" must equal at least 3 percent of retail sales in 2012, 9 percent in 2016, and 15 percent in 2020. Figure 1-6 compares existing qualifying renewable resources with this annual target, and shows that PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law through 2022. By 2023, PSE will need just over 100 MW of additional wind resources.

Qualifying renewable energy is expressed in annual qualifying renewable energy credits (RECs) rather than megawatt hours, because the state law incorporates multipliers that apply in some cases. For example, generation from PSE's Lower Snake River wind project receives a 1.2 REC multiplier, because qualifying apprentice labor was used in construction. Thus the project is expected to generate approximately 900,000 MWh per year of electricity, but would contribute about 1,080,000 equivalent RECs toward meeting the renewable energy target. Note this is a long-term compliance view. PSE has sold surplus RECs to various counterparties in excess of those needed for compliance and will continue to do so as appropriate to minimize costs to customers.

Figure 1-6: Renewable Resource/REC Need



Electric Portfolio Resource Additions Forecast

As explained above, the lowest reasonable cost portfolio produced by the IRP analysis is not an action plan, rather, it is better understood as a forecast of resource additions PSE would find cost effective in the future, given what we know about resource and market trends today. It incorporates significant uncertainty in several dimensions.

Figure 1-7 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 20 years. This forecast is the "integrated resource planning solution."[12] It reflects the lowest reasonable cost portfolio of resources that meets the projected capacity, energy and renewable resource needs described above. Generally, this resource strategy is similar to prior IRPs: it accelerates acquisition of energy conservation, acquires renewable resources to meet requirements of RCW 19.285, and forecasts that natural gas plants are cost effective for meeting remaining needs. There is one difference in this IRP: the mix of gas plants. In this IRP, we find a combination of peakers and combined cycle plants are the most reasonable balance of cost and risk.

Figure 1-7: Electric Resource Plan Forecast, Cumulative Nameplate Capacity of Resource Additions

	2021	2026	2030	2035
Conservation (MW)	411	669	770	906
Demand Response (MW)	121	130	138	148
Wind (MW)	-	206	337	337
Combined Cycle Gas (MW)	-	577	577	805
Peaker/CT Dual Fuel (MW)	277	403	609	609

12 / *Chapter 2 includes a detailed explanation of the reasoning that supports each element of the resource plan.*

Demand-side Resources: Energy Efficiency. This plan – like prior plans – includes acquiring conservation to levels such that much of what is available will be acquired. That is, significant changes in avoided cost had little impact on how much could be acquired cost effectively. PSE's analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy.

Demand-side Resources: Demand-response. In this IRP, we are seeing a significant increase in the amount of demand-response programs. These include direct residential load control programs and voluntary interruptible rate schedule programs for commercial and industrial customers.

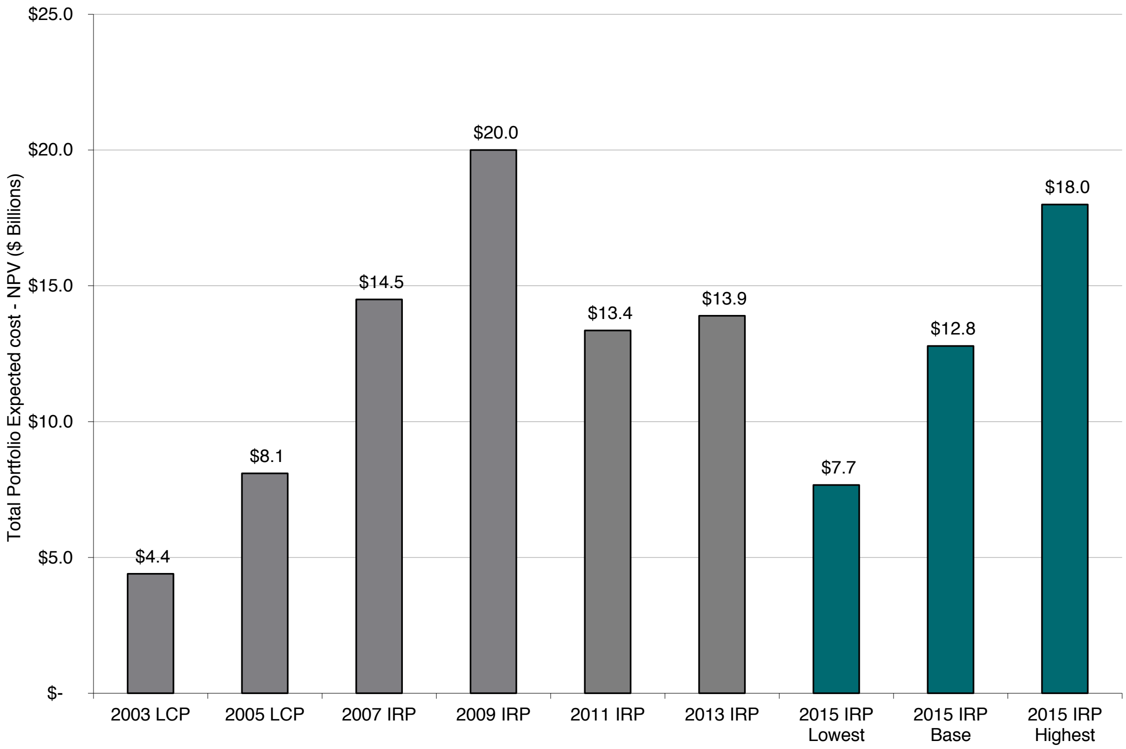
Renewable Resources. Timing of renewable resource additions is driven by requirements of RCW 19.285. PSE's analysis shows that while additional wind is not a least-cost resource, we anticipate remaining comfortably below the four percent revenue requirement cap. PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law through 2022.

Peakers vs. Combined-cycle Plants: It depends . . . In all future scenarios, gas-fired plants appear to be the most cost-effective supply-side resource for meeting our customers capacity and energy needs – at least until technology changes. This IRP forecasted that peakers were more cost effective in some scenarios, and combined-cycle combustion turbine (CCCT) plants were more cost effective in others. To a large extent, this depended on whether sufficient backup fuel could be permitted for peakers and how carbon regulations might affect operation of CCCT plants across the WECC. Given this uncertainty, we adopted a strategy that includes both types of plants. This mixed approach reduces expected cost and risk relative to an all-CT portfolio, which appeared to be cost effective in the 2013 IRP.

Costs and Carbon Emissions

Portfolio Costs. The long-term outlook for incremental portfolio costs has been dynamic across IRP planning cycles since 2003, driven by changing expectations about natural gas prices and costs associated with carbon regulation. Conservation, gas-fired generation and wind have been the primary resource alternatives since 2005. Figure 1-8 illustrates how incremental portfolio costs have changed over time, along with the context for the range of costs examined in this IRP. Note that in this IRP, carbon costs are included in the IRP Base Scenario assumptions. However, gas prices dropped significantly causing portfolio costs to go down.

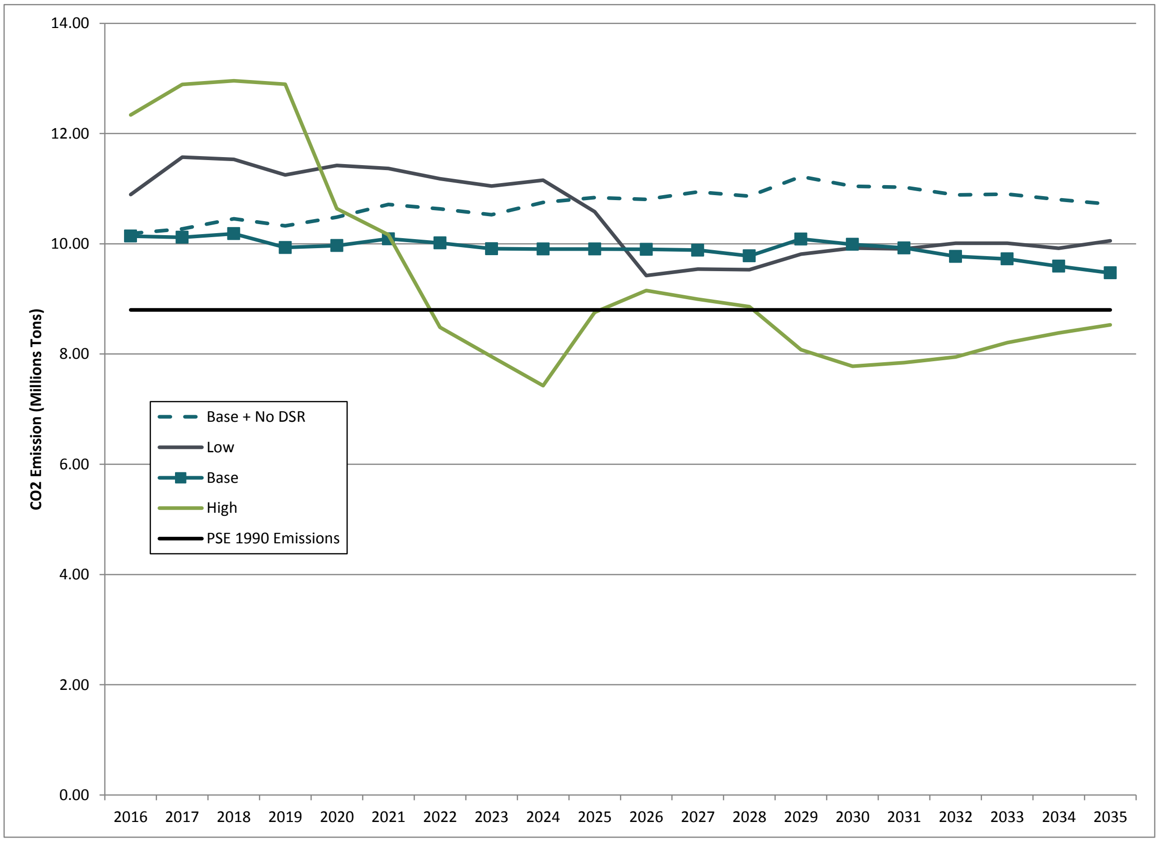
Figure 1-8: Incremental Portfolio Costs Over Time



Carbon Emissions Associated with Electric Service. A number of Washington state laws address carbon emissions. RCW 70.235 adopts a state goal for reducing emissions. RCW 80.80 sets an emissions performance standard (EPS) that prevents utilities from entering into long-term financial commitments for baseload electric generation unless the generation source complies with the greenhouse gas emissions performance standard set by the state, effectively banning purchases from additional coal plants or older gas CCCT plants. In 2011, the legislature amended the EPS to achieve permanent reduction of certain CO_2 emissions by retiring the TransAlta coal plant in Centralia, Washington. Utilities are allowed to enter into long-term contracts for "coal transition power" from TransAlta, and TransAlta will shut down one generating unit at the Centralia coal plant by the end of 2020 and the other by the end of 2025. TransAlta also will provide financial assistance for local economic development and clean energy. RCW 19.285, the Energy Independence Act, requires electric utilities to reach certain targets for renewable resources and acquire all cost-effective achievable conservation. Meanwhile, according to WAC 480-100-238, "Each electric utility regulated by the commission has the responsibility to meet its system demand with a least cost mix of energy supply resources and conservation."

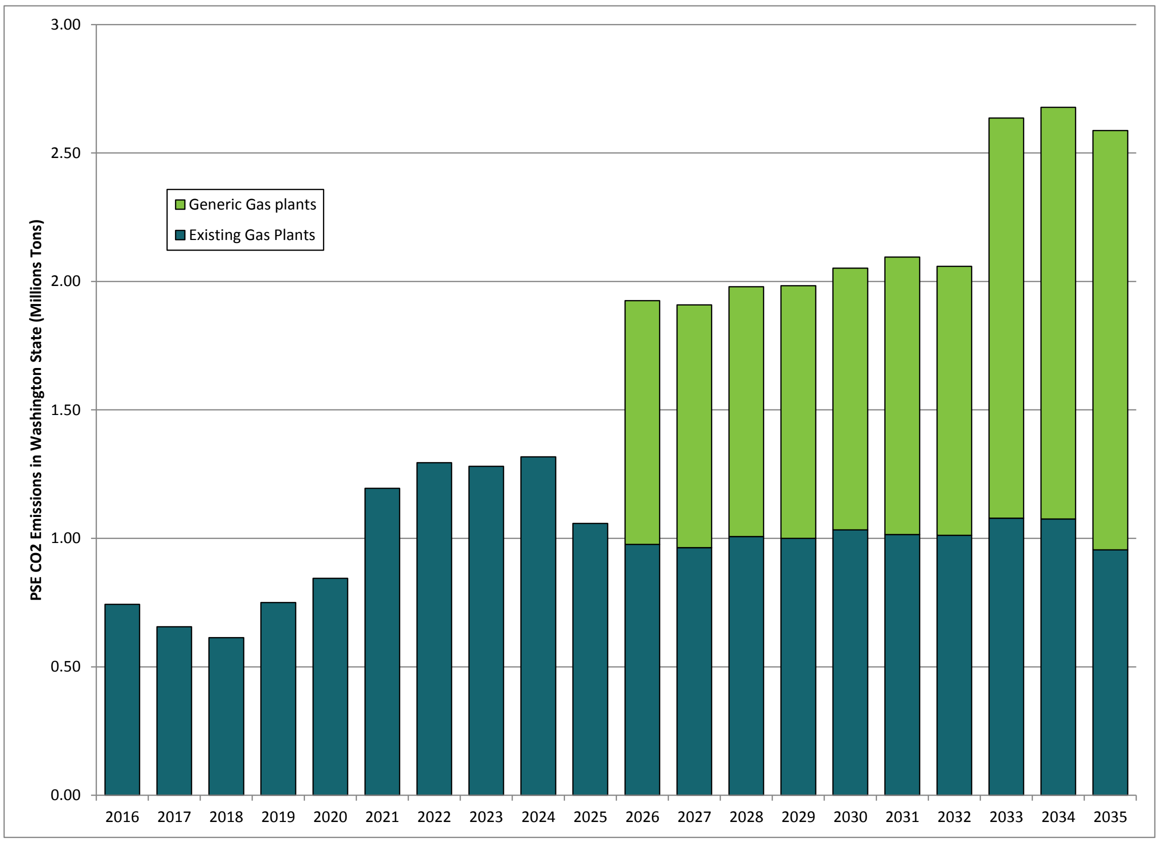
The combined impact of these laws, rules and policies on PSE's CO_2 emissions from electric operations is shown in Figure 1-9. The initial ramp-up in CO_2 emissions followed by a reduction in the Low Scenario is due to PSE's coal transition power agreement with TransAlta that expires in 2025; ultimately, this contributes to the retirement of the 1,460 MW Centralia coal plant and a permanent reduction of emissions. The Base Scenario emissions remain flat across the 20 year time horizon. Due to the high CO_2 price modeled in the Base Scenario, the Centralia coal plant is reduced to a 20 percent capacity factor and most of the contract is being supplied by market. The contract is then replaced by a CCCT plant in 2026, so the emissions of the contract offset the emissions of the CCCT. The High Scenario emissions dropped in 2020 from the impact of the high CO_2 price that starts in 2020. The chart also shows a significant reduction in emissions from acquisition of all cost-effective conservation. By 2035, the cumulative CO_2 savings over the 20-year time horizon from conservation is approximately 16.11 million tons.

Figure 1-9: Projected Annual Total PSE Portfolio CO_2 Emissions and Savings from Conservation



The forecast of PSE's total portfolio emissions may be of interest to policy makers, but PSE's direct Washington emissions may have a more significant impact on the state. Emissions generated within the state will be impacted by Washington's implementation plan for the EPA's Clean Power Plan[13] and also the alternatives developed by policy makers to achieve the state's emission reduction goals under RCW 70.235. Figure 1-10 shows in-state emissions forecast for PSE's plants in Washington state, separating emissions from existing plants and new plants from the resource plan. This shows increasing emissions in Washington State associated with adding new, efficient combined cycle plants.

Figure 1-10: Forecast of PSE's Washington Direct-Generation CO_2 Emissions



13 / *Section 111(d) of the Clean Air Act, often referred to as "111(d)."*

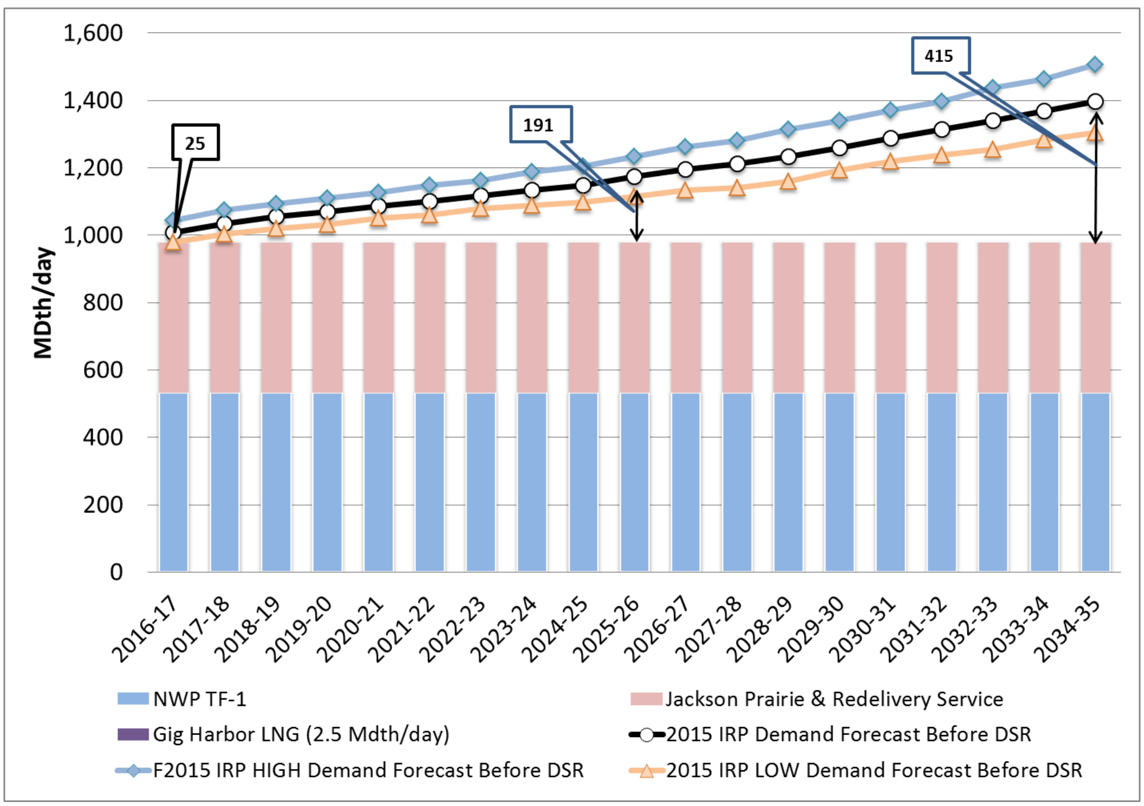
GAS SALES RESOURCE PLAN FORECAST

PSE develops a separate integrated resource plan to address the needs of more than 790,000 retail gas sales customers. This plan is developed in accordance with WAC 480-90-238, the IRP rule for gas utilities. (See Chapter 7 for PSE's gas sales analysis and Chapter 6 for PSE's analysis of gas for power need.)

Gas Sales Resource Need

Gas sales resource need is driven by design peak day demand. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD). Like electric service, gas service must be reliable every day, but design peak drives the need to acquire resources. Figure 1-11 illustrates the load-resource balance for the gas sales portfolio. The chart demonstrates a need for resources beginning in the winter of 2016/17.

Figure 1-11: Gas Sales Design Peak Day Resource Need



Gas Sales Resource Additions Forecast

Figure 1-12 summarizes the gas resource plan additions PSE forecasts to be cost effective in the future in terms of peak day capacity and in MDth per day. As with the electric resource plan, this is the "integrated resource planning solution." It combines the amount of demand-side resources that are cost effective with supply-side resources in order to minimize the cost of meeting projected need. Again, this is not PSE's action plan – it is a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource trends and market trends today.

Figure 1-12: Gas Resource Plan Forecast,
Cumulative Additions in MDth/Day of Capacity

Base Scenario MDth/day	2018-19	2022-23	2026-27	2034-35
Demand-side Resources	12	29	46	69
PSE LNG Project	69	85	85	85
Swarr Upgrade	30	30	30	30
NWP/Westcoast Expansion	-	34	49	102
Mist Storage Expansion	-	-	50	50
Cross Cascades to AECO Expansion	-	-	10	10
Cross Cascades to Malin Expansion	-	-	-	99
Total	111	178	270	445

Demand-side Resources (DSR). Analysis in this IRP applies a 10-year ramp rate for acquisition of DSR measures. Analysis of 10- and 20-year ramp rates in prior IRPs has consistently found the 10-year rate to be more cost effective. Ten years is chosen because it aligns with the amount of savings that can practically be acquired at the program implementation level.

PSE LNG Project. PSE is in the early stages of developing a liquefied natural gas (LNG) project to provide peak day supply to PSE's gas customers as part of a larger LNG project that would support the needs of emerging transportation markets. Converting local maritime traffic and truck transport to natural gas fuel will significantly improve local air quality and reduce greenhouse gas emissions. If such a multi-purpose project is constructed, this IRP finds the project's capacity to provide peaking supplies would be cost effective for our gas customers.

Swarr Upgrade. This IRP finds that upgrading the Swarr LP-Air facility environmental safety and reliability systems and returning the Swarr production capacity to its original 30 MDth per day capability may be a cost-effective resource. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary work necessary to upgrade Swarr is under way.

Northwest Pipeline/Westcoast Expansion. Additional transportation capacity from the producing regions in British Columbia at Station 2 south to PSE's system on the Westcoast pipeline is also forecast as cost effective beginning in 2022 based on lower projected pipeline costs than the alternatives.

Mist Storage Expansion. The Mist storage expansion is selected in most scenarios starting in 2026-27. This result means that PSE will continue to consider pursuing acquiring storage capacity at Mist, keeping in mind that Mist expansion is dependent on expansion of NWP from Sumas to the Portland area.

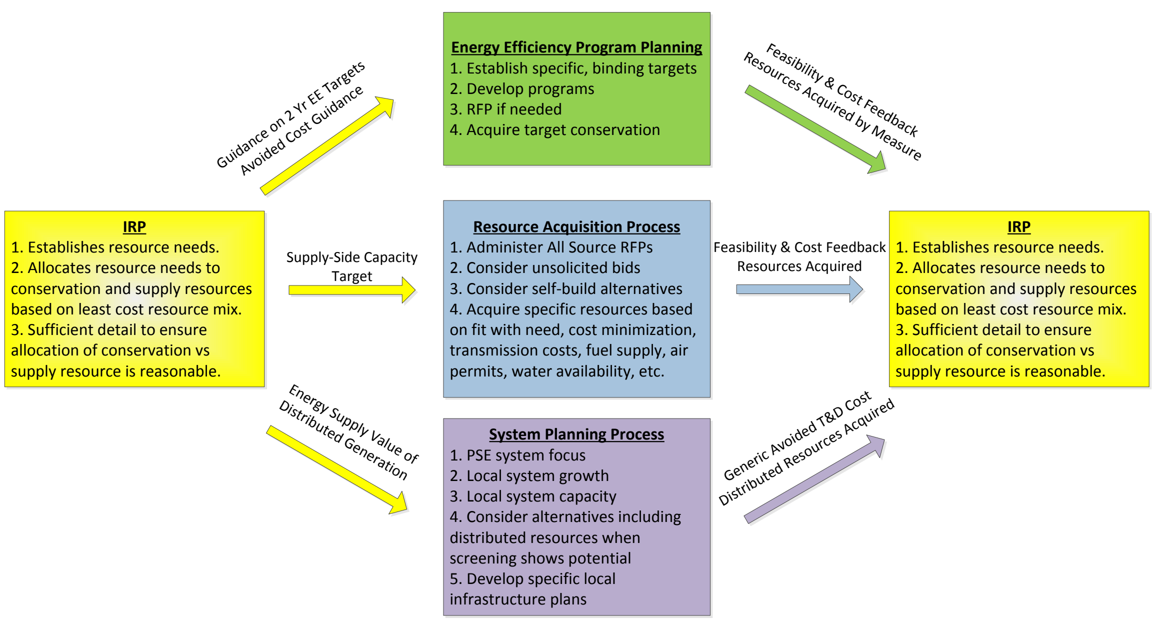
Cross Cascades Expansion. The analysis in this IRP indicated that in the later years of the planning horizon, a Cross Cascades expansion coupled with existing or new upstream pipeline to the liquid AECO or Malin gas hubs could be a cost-effective option for our gas customers. PSE will continue to consider these pipeline expansion options as they become more tangible and analyze their potential benefit for our customers as cost-effective resources.

THE IRP AND THE RESOURCE ACQUISITION PROCESS

The IRP is not a substitute for the resource-specific analysis done to support specific acquisitions, though one of its primary purposes is to inform the acquisition process. The action plans presented here help PSE focus on key decision-points it may face during the next 20 years so that we can be prepared to meet needs in a timely fashion.

Figure 1-13 illustrates the relationship between the IRP and activities related to resource acquisitions. Specifically, the chart shows how the IRP directly informs other acquisition and decision processes. In Washington, the formal RFP processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and self-build (or PSE demand-side resource programs) must also be considered when making prudent resource acquisition decisions. Figure 1-13 also illustrates that information from the IRP also provides information to the local infrastructure planning process.

Figure 1-13: Relationship of IRP to Resource Decision Processes



RESOURCE PLAN DECISIONS

Contents:

The resource plan in this IRP represents "…the mix of energy supply and conservation that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers."[1] It is the culmination of comprehensive quantitative and qualitative analyses, including extensive risk analysis, reported throughout the document.

The electric and gas resource plans included in the IRP are best understood as long-term forecasts of what will be cost effective in the future, given what we know about the future today. The IRP is not a plan for acquiring specific demand-side or supply-side resources. Resource decisions can be informed by the foresight developed in the IRP, but ultimately they will be made when it best serves the interest of our customers, and they will depend upon actual market opportunities and updated assessments of market conditions. This chapter summarizes the reasoning for the additions to the electric and gas resource plans.

1 / WAC 480-100-238 (2) (a) Definitions, Integrated Resource Plan.

ELECTRIC RESOURCE PLAN

This discussion assumes the reader is familiar with the key assumptions described in Chapter 4. Further information on the analyses discussed here can be found in Chapters 4, 5, 6, 7 and the Appendices.

Capacity Planning Standard Update

DECISION. This IRP adopts an optimal planning standard that reflects a benefit/cost analysis designed to minimize the net cost of reliability to customers. The analysis also incorporates wholesale market risk in its peak capacity assessment of wholesale market purchases, consistent with regional resource adequacy assessments.

SUMMARY. The updated standard and incorporation of market risk reduces the expected value of lost load to customers by $130 million per year. The cost to achieve that expected savings is $63 million per year, for a net benefit to customers of $67 million per year. Risk reduction is dramatic. The $63 million per year cost reduces the risk to customers by $1.3 billion per year.

FACTORS THAT COULD AFFECT DECISION. Changes to the region's resource adequacy assessment and/or changes to PSE's load forecast could impact the amount of capacity PSE needs to acquire, but this would not change the approach. We will continue to base our planning standard on the value of reliability to customers unless the Commission expresses significant concerns about the approach in its letter on the 2015 IRP.

DISCUSSION. Since regional resource adequacy studies forecast a shift from surplus to deficit in the region's load/resource balance, this a particularly appropriate time to focus PSE's electric planning standard on the value of reliability to customers and to incorporate wholesale market risk in the analysis.

The old planning standard called for maintaining enough peak capacity to achieve a 5 percent loss of load probability (LOLP). This is a reasonable, industry-standard approach, adopted by the Northwest Power and Conservation Council (NPCC) for it's regional resource adequacy assessment and adopted by PSE in 2009, but it is not based on the value of reliability to customers. That is, the 5 percent LOLP does not explicitly consider the value of reliability to customers or the cost to provide that reliability. This IRP focuses on those tradeoffs, so that we can be sure we are providing the optimal balance of cost and risk to our customers.

Prior IRPs also assumed wholesale market purchases were 100 percent reliable, but this is no longer a reasonable assumption now that surplus capacity in the region is shrinking. Therefore, PSE incorporates wholesale market risk into the analysis to support its capacity planning standard. Figure 2-2, Summary of Planning Standard Changes, provides information that will be used in the discussion below. Additional detail is included in Chapter 6, Electric Analysis, Appendix G, Wholesale Market Risk, and Appendix N.

Figure 2-1, Summary of Planning Standard Changes

		Reliability Metric		2021 Peaker Capacity Added after DSR (MW)	Customer Value of Lost Load	
		LOLP	EUE (MWh)		Expected ($mill/yr)	TVar90 ($mill/yr)
1	2013 Planning Standard No Market Risk	5%	26	(150)	86*	858*
2	2013 Planning Standard with Market Risk	5%	50	(117)	169	1,691
3	2015 Optimal Planning Standard (Includes Market Risk)	1%	10.9	234	39	385

** Inaccurate estimate because it ignores reliability impact of wholesale market risk.*

To understand the impact of the change, it is helpful to understand what the reliability metrics in the table in Figure 2-1 represent. Loss of load probability (LOLP) is a measure of the likelihood of a load curtailment occurring; expected unserved energy (EUE) is a measure of the magnitude of potential load curtailments, in other words, how much load and how many customers are likely to be impacted.

In line one of Figure 2-1, the 2013 Planning Standard – which is focused on a 5 percent LOLP and ignores market risk – indicates that PSE would be surplus 150 MW in 2021. In line two, when the 2013 standard includes market risk, the surplus diminishes to 117 MW. From this perspective, recognizing market risk would require PSE to add 33 MW to maintain the 5 percent LOLP. However, the real impact of ignoring risk can be seen in the EUE and customer value of lost load sections on these two lines. Recognizing market risk nearly doubles EUE, the customer value of lost load and risk. EUE increases from 26 MWh to 50 MWh; the expected customer value of lost load increases from $86 million to $169 million; and risk increases from $858 million to $1,691 million.

These results highlight the need for a new planning standard. Focusing only on LOLP misses the fact that customer curtailments would be almost twice as high. Clearly, a more comprehensive approach to defining the planning standard is needed.

The 2015 Optimal Planning Standard. To develop the 2015 Optimal Planning Standard, we focused on the benefits and costs to customers of improving reliability. Translating MWh of lost load into a dollar metric based on its value to customers facilitated performing a benefit/cost analysis to define the optimal planning standard. The word "optimal" is used here in an economic context. The analysis compared the cost to customers of potential outages with the cost of adding generating resources to increase service reliability to find the "optimal" level of reliability – the point at which the benefit to customers of increased reliability (marginal benefit) equals the cost of providing that level of reliability (marginal cost).

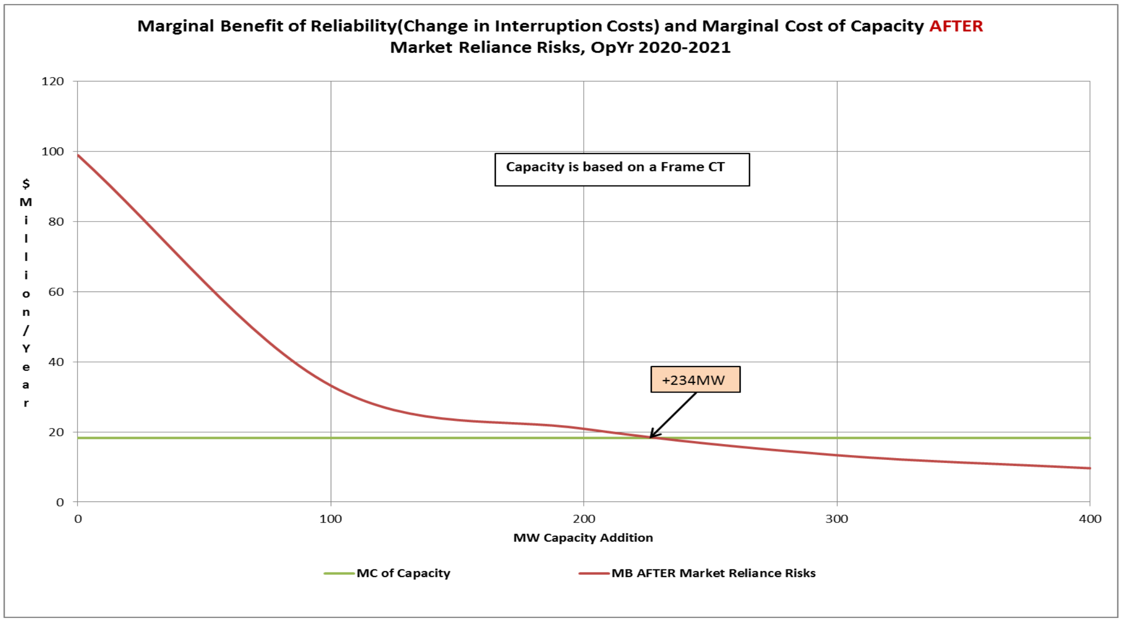
Again, Figure 2-1 shows that moving to the 2015 Optimal Planning Standard reduces the expected value of lost load to customers by $130 million per year.[2] The cost to achieve that expected savings is $63 million per year,[3] for a net benefit to customers of $67 million per year. Risk reduction to customers is dramatic. That $67 million per year cost reduces the risk to customers by $1.3 billion per year.[4]

Figure 2-2 illustrates where the marginal benefit and marginal cost of reliability to customers intersects at the optimal planning standard. This chart shows that as generation increases, the incremental benefit created by that addition falls. This is because fewer and fewer outages are avoided by the increased generation. The incremental cost is constant (shown here as the incremental cost of adding 100 MW blocks of generation). The chart shows that if we stopped adding generation before 234 MW, we would be leaving value on the table for customers, because the benefits exceed costs up to that point. On the other hand, adding generation beyond 234 MW would cost customers more than it saves, reducing the net benefit to customers to below the $67 million per year.

2 / *From Figure 2-1. This is calculated by comparing the Expected VOLL in line 2 (2013 Planning Standard Including Market Risk) with the Expected VOLL in line 3 (2015 Optimal Planning Standard): $169 million - $39 million= $130.*
3 / *This value is derived by first calculating the difference between the surplus of 117 MW in line 2 (2013 Planning Standard Including Market Risk) and the need (deficit) of 234 MW in line 3 (2015 Optimal Planning Standard). This value is then multiplied by the levelized cost of a peaker, estimated from the portfolio model at $0.18 million per MW per year. So: 234 MW – (-117 MW) = 351 MW. Then: 351 MW * $0.18 million per MW per year = $63 million per year.*
4 / *$1,691 million - $385 million = $1,306 million*

Using this benefit/cost approach will enable us to continue to identify the optimal planning standard even as conditions in the region and PSE's service territory change over time.

Figure 2-2: Marginal Benefit and Marginal Cost of Reliability to Customers



Regional Resource Configuration Assumptions

Incorporating wholesale market risk in the analysis required us to make certain assumptions about regional resource configurations. We began with the assumptions in the May 2015 NPCC regional resource adequacy study and made three key adjustments.

1. **SOUTHWEST IMPORTS WERE INCREASED BY 475 MW.**
   The NPCC's base analysis assumes 3,400 MW of transmission capacity is available from California, but only 2,925 MW of winter season on-peak resources were included in the analysis (2,500 MW of spot market purchases plus 425 MW of long-term contracts). We added the spot market import amounts necessary such that total imports from California equal 3,400 MW on all hours. It seemed reasonable to assume that this additional capacity would be available during the region's peak need season.

2. **REGIONAL GENERATION WAS INCREASED BY 440 MW.**
   Portland General Electric (PGE) has plans to acquire 440 MW of firm generation by 2021, when their Boardman coal plant retires. Information from PGE demonstrates a strong preference for that generation to be a non-intermittent renewable resource. PGE is, however, prepared to build Carty 2, which would be 440 MW gas CCCT plant if adequate renewable resources are not available. This plant did not meet the criteria to include in the NPCC's regional adequacy analysis, but it seems reasonable to assume that it will be built, and we did not want to overstate our resource needs.

3. **REGIONAL GENERATION WAS REDUCED BY 650 MW.**
   This adjustment assumes the 650 MW Grays Harbor CCCT is not available to operate during PNW load curtailment events. This gas-fired generating plant appears to rely solely on wholesale market purchases of interruptible fuel supply. It has neither firm pipeline capacity for natural gas fuel supply nor oil backup, which means that under extreme cold weather conditions – when the region is most likely to have a capacity deficit – the plant may not be able to operate until weather conditions improve and wholesale market gas supplies are available again. The NPCC assumed firm fuel supply in its regional adequacy analysis because of the difficulty of determining when the plant might be unable to obtain supplies, but it would be inconsistent for PSE to include the plant in our regional resource configuration since we would not be able to consider it firm for our customers if it were in our portfolio. Removing Grays Harbor from the regional adequacy study ends up increasing PSE's resource need by approximately 64 MW.[5]

5 / See Appendix G, Wholesale Market Risk, for additional detail.

Resource Additions Summary

Figure 2-3 summarizes the forecast of resource additions to the company's electric portfolio that resulted from the 2015 IRP analysis. The plan forecasts accelerated acquisition of conservation and demand-response in the early years, the addition of a natural gas-fueled peaking plant in 2021-22, and the addition of renewable resources by 2023 to meet RCW 19.285 (Northwest wind). Further out, CCCT plants are added starting in 2026 as the coal plant retirements begin to impact need. Additional renewables before 2023 were not included, because the stochastic portfolio analysis demonstrated that additional wind (the least cost renewable) did not reduce cost or reduce risk. The discussion below summarizes key decisions for the resource plan.

Figure 2-3: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

	2021	2026	2030	2035
Conservation (MW)	411	669	770	906
Demand Response (MW)	121	130	138	148
Wind (MW)	-	206	337	337
Combined Cycle Gas (MW)	-	577	577	805
Peaker/ CT Dual Fuel (MW)	277	403	609	609

Electric Results across Scenarios

Figure 2-4 summarizes the demand- and supply-side resource additions to PSE's existing resource portfolio across scenarios; this picture is the product of the deterministic portfolio optimization analysis. For each scenario, the analysis considered supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (customer demand across all hours), and renewable energy need (to meet RCW 19.285 targets). The portfolios in Figure 2-4 minimize long-term revenue requirements (costs as customers will experience them in rates), given the market conditions and resource costs assumed for each scenario.

Least-cost portfolio builds are similar across most scenarios, with respect to renewables and demand-side resources, though the choice of gas resources differs. This consistency is a powerful finding. It means that the wide variety of external market factors modeled in these scenarios will have little impact on the selection of renewables and demand-side resources.

Figure 2-4: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW), 2015 Optimal Planning Standard

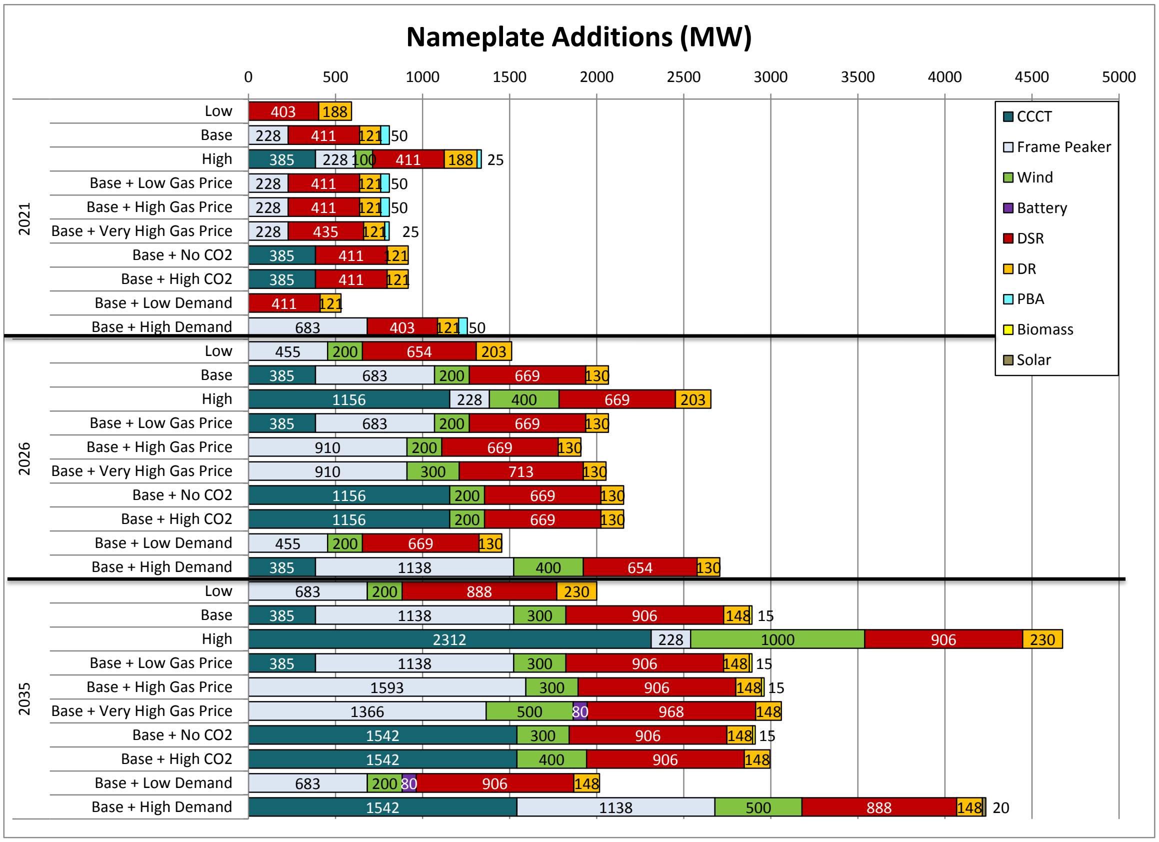
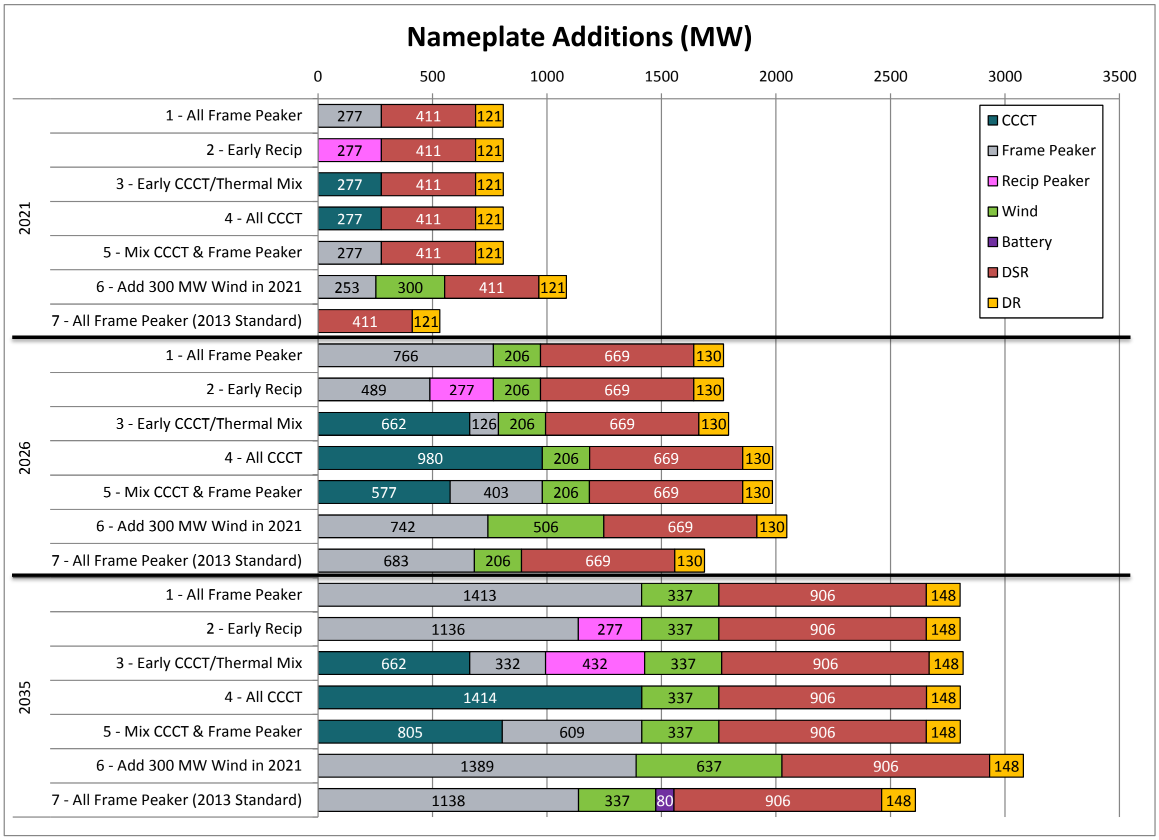


Figure 2-4, above, highlights that gas plant additions differed across the scenarios. To further explore gas resource choices, we developed a set of six candidate resource strategies for the stochastic phase of the analysis, to test how different combinations of gas plants would perform across all futures. We also included a strategy that added more wind than the minimum required under RCW 19.285. These strategies, developed as a result of the deterministic analysis, are summarized as follows:

1. All frame peakers.
2. Early reciprocating engine peaker, with frame peakers for remaining thermal plants.
3. Early CCCT plants, with a mix of CCCT and frame peakers.
4. All CCCT plants.
5. Mix of frame peakers and CCCT plants, with frame peaker first
6. Add 300 MW of wind beyond RPS requirements.

Figure 2-5 illustrates the additions produced by stochastic analysis of the six strategies.

Figure 2-5: Stochastic Analysis Results for Six Candidate Resource Strategies



In the end, strategy five, a combination of peakers and CCCT plants, appeared to provide the best combination of cost-effectiveness, flexibility and risk management

A detailed discussion of each element of the resource plan follows.

Demand-side Resource Additions

Energy Efficiency

DECISION. Energy efficiency measures are forecast to total 411 MW by 2021 and increase to 906 MW by 2035. This includes both PSE-implemented programs and the effect of new codes and standards.

SUMMARY. Least-cost energy efficiency levels were consistent across the wide range of scenarios and sensitivities examined. The level chosen is consistent with results from the seven of the ten scenarios tested including the Base Scenario.

FACTORS THAT COULD AFFECT DECISION. Little change is expected in the near term, since PSE works with the CRAG to develop conservation targets based on these IRP results. Longer-term, changes in technology or policies could impact future conservation targets in the IRP.

DISCUSSION. Least cost portfolios in 7 of the 10 scenarios (including the Base Scenario) included the same level of conservation, shown in Figure 2-4, above. By the end of the planning horizon, the lowest conservation result was only 18 MW lower than the Base Scenario result, and the highest was 62 MW higher by 2035. By 2021, the difference between highest and lowest levels was only 32 MW.

Demand-response

DECISION. The plan forecasts acquiring 121 MW of demand-response by 2021.

SUMMARY. Cost-effective levels of demand-response were found to be consistent across nearly all scenarios. In the Action Plan for the 2015 IRP, PSE commits to developing and executing an acquisition process focused on demand-response separate from other resources.

FACTORS THAT COULD AFFECT DECISION. The acquisition process may reveal costs or attributes different from those assumed in the IRP, and this could lead to adjusting the amount of demand-response acquired up or down. Changes to resource need are driven by updates to the long-term load forecast and revisions to the regional resource adequacy analysis may also affect the quantity of demand-response.

DISCUSSION. The level of cost-effective demand-response across scenarios was even more consistent than conservation results. By 2021, 121 MW of demand-response was found cost effective in all but two cases. (An additional 66 MW was found cost effective in the High and Low Scenarios.) Evaluation of demand-response will continue in future IRPs, so that we can adjust amounts appropriately as market conditions change.

Renewable Resource Additions

DECISION. The plan forecasts the addition of 206 MW of southeast Washington wind to the portfolio by 2023, followed by another 131 MW by 2028.

SUMMARY. Southeast Washington wind is forecast to be the most cost-effective renewable resource for compliance with RCW 19.285. Additional wind beyond the law's requirements was not cost-competitive with non-renewable resources, nor did it mitigate risk. Therefore, the resource plan includes additional resources to meet compliance obligations only.

FACTORS THAT COULD AFFECT DECISION. Three key factors could affect the amount or mix of renewables added in the future: changes to the load forecast, to public policy or to renewable technologies.

1. RCW 19.285 is a load-based requirement, so changes that affect the load forecast will also impact renewable needs.
2. Public policy changes could alter renewable requirements in the future either directly or indirectly. A direct example would be changing the energy requirements in RCW 19.285. An indirect example would be using an emission rate approach to state implementation of EPA's Clean Power Plan rule 111(d).
3. Technological innovation could result in renewable resources becoming cost competitive with non-renewable resources,[6] or in changes to the mix of renewables. For example, utility scale solar may become more cost effective than southeast Washington wind in the future.

DISCUSSION. The addition of wind beyond requirements was found to be cost effective only in the High Scenario, which models both high gas prices and high carbon costs. In candidate resource strategy 6, we also examined whether additional wind could reduce portfolio risk enough to justify its inclusion in the portfolio. The analysis indicated that this would slightly reduce risk of the portfolio, as can be seen in Figure 2-6 where (TailVar90 falls by $13 million NPV. This is the first time PSE has found wind to reduce portfolio risk, but the cost was high; it would cost $239 million to protect against a $252 million loss. Adding capacity for reliability purposes, as described in the planning standard discussion, would reduce risk at a far smaller cost.

6 / To reduce renewable resource costs to the point where they can compete with market energy in this part of the country will require significant advances, because of the amount of low variable cost hydro generation available in the Pacific Northwest.

Figure 2-6: Results of Stochastic Analysis

NPV ($Millions)	Base Deterministic Portfolio Cost	Difference from Base	Mean	Difference from Base	TVar90	Difference from Base
1 - All Frame Peaker	**12,531**		**11,343**		**14,589**	
6 - Add 300 MW Wind in 2021	12,798	267	11,582	239	14,576	(13)

Having established the level of renewables, the last step in this portion of developing the resource plan was to determine the timing and exact amounts of wind to include in the resource plan. To make those decisions, we aggregated up renewable builds at key periods, to reflect the lumpiness of renewable investments while reflecting the ability to scale those resources.

Based on the current load forecast, and the ability to bank renewable energy credits (RECs), additional wind is not needed until 2023. 203 MW of wind would meet regulatory requirements until 2028, when a combination of slight load growth and expiration of a long-term, 50 MW contract for output from the Klondike wind farm expires. At 2028, an additional 131 MW of wind would be sufficient to meet requirements through 2035. It is possible that other resources and different strategies will emerge by 2028, based on evolving market conditions and changing energy policies. We will complete 5 more IRPs by 2025, so will be able to adjust strategies and decisions as the future unfolds.

This IRP also examined the possibility of acquiring wind from Montana. The challenge is that Montana wind does not generally qualify as a renewable resource under RCW 19.285 because it is outside the Pacific Northwest footprint. Therefore, Montana wind would have to be cost-competitive with other supply alternatives. This would be difficult because of the transmission costs involved. Chapter 6 describes the analysis of potential transmission options and costs PSE conducted for this IRP. Results indicated the capacity contribution of Montana wind would have to be greater than 50% to be cost effective. Under certain sets of assumptions, the results estimated a capacity value of 55%, so it is possible that Montana wind could appear cost effective under some future market conditions. PSE will continue to refine its assumptions for this resource in future IRP analyses.

Biomass and solar were also included in the optimization analysis. Minor amounts of biomass,15 MW, appear least cost in a few scenarios. One scenario also included 20 MW of utility-scale solar in the last few years of the planning horizon. Biomass and utility scale solar appeared cost effective in those scenarios primarily because they satisfied a small renewable need toward the very end of the planning horizon, so they were the “right size” compared to larger scale wind resources. Ultimately, the analysis found that adding 131 MW of wind in 2028 instead of 100 MW, would cover that small renewable need at a lower cost than either biomass or solar. Market conditions, energy policies, and load forecasts will most like change significantly by 2030, and this analysis highlights that PSE should continue examining feasibility of biomass and utility scale solar resources.

Supply-side Resource Additions

DECISION. Forecast additions include a mix of frame peakers and CCCT plants; the first addition will most likely be a frame peaker with backup fuel that does not require firm interstate gas pipeline capacity. CCCT plants are included to meet larger needs, including the expiration of PSE’s contract with Centralia in 2026.

SUMMARY. Forecasting a combination of frame CTs and CCCT plants for the resource plan is reasonable, based on consideration of the quantitative and qualitative analyses. While deterministic scenario analysis shows CCCT plants would be more cost effective than frame peakers in some scenarios, and stochastic analysis also shows CCCT plants would be more cost effective than frame peakers, the qualitative consideration of several factors tips the balance toward including frame peakers. These include assumptions about firm gas pipeline capacity requirements for frame peakers, the ability of frame peakers to meet smaller increases in capacity need more cost-effectively than CCCTs, and uncertainty about the direction of future market conditions.

FACTORS THAT COULD AFFECT DECISIONS. It is important to emphasize again that the resource plan is a forecast of resource additions that appear to be cost effective given what we know about the future today. Four key factors will impact how the future acquisition of gas plants will unfold.

1. ***Resource Need and Optimal Sizing of Plants.*** Changes in the size of our capacity resource needs will impact the choice of technology. Large increases in capacity need tilt the portfolio toward CCCT plants, while smaller capacity need increases could be more cost-effectively met with peaking plants. So, when PSE's contract with the Centralia coal plant expires, when a portion of Colstrip needs to be replaced, or when there is significant load growth, CCCT plants will fit PSE's needs well. Smaller increases in capacity need will tend to tilt the portfolio toward frame peakers.

2. ***Fuel Assumptions for Frame Peakers.*** Changes in the availability of non-firm gas supply may also impact technology choices. In this IRP, frame peakers are assumed to need sufficient firm pipeline capacity to run for 12 on-peak hours, with backup fuel being used for any remaining reliability need. However, when frame peakers can avoid the cost of firm pipeline capacity by operating with a combination of non-firm gas and backup fuel oil, peakers look more cost effective even in the stochastic analysis.

   An extensive analysis of sufficiency of back-up fuel inventories applied to our existing peaker fleet is reported in Chapter 6, Electric Analysis. We are confident that at least one more frame CT can be added without needing firm pipeline capacity for reliability, even taking into account very conservative assumptions about the availability of non-firm gas supply and air permit limitations. Beyond the next peaking plant, the ability to construct a backup fuel tank and obtain adequate air permits will depend on its location and the applicable emission regulations.

3. ***Future Energy Policies***. Changes in the direction of energy policy could also impact technology choices. Some policies designed to reduce carbon emissions tip the economics toward frame peakers, while others favor CCCTs. This uncertainty suggests minimizing long-term fixed cost commitments to plants that may end up being uneconomic; that is, it favors smaller frame peakers with backup fuel, because they do not require long-term gas pipeline commitments. But, different carbon reduction policies will have different impacts. Marketwide policies that seek to reduce coal generation across the WECC on a consistent basis increase the relative value of CCCT plants, making them more cost effective; however, when similar policies are applied on a state-by-state basis, things become complicated. For example, a hard carbon cap in Washington could limit the run hours for CCCT plants, increasing costs and reducing the cost effectiveness of CCCT. On the other hand, if other states impose similar caps, less energy will be available across the entire WECC, which could driving up market prices and the value of CCCT plants. Policies that include carbon caps tied to an undefined or unclear carbon market for offsets do little to alleviate this uncertainty. Changes in

renewable portfolio standards can also impact the relative value between types of gas plants.

4. ***Value of Sub-Hourly Flexibility and Technology.*** Changes in the relative flexibility values of 4. different resources could change technology decisions. Analysis in this IRP incorporated initial estimates of sub-hourly flexibility value of different resources, including CCCT, batteries, frame and other peakers, and reciprocating engines. Including flexibility value improved the value of reciprocating engines to the degree that they supplanted CCCT and other peakers in terms of cost effectiveness. However, while the reciprocating engines examined in this IRP appear to be cost effective from the perspective of flexibility benefits, their particulate emissions may exceed recent EPA standards. We plan to upgrade our sub-hourly flexibility modeling, and will continue to study possible particulate emission concerns. Should there be a solution for those concerns, reciprocating engines may become a least-cost resource.

DISCUSSION. The results for gas plants in the deterministic portfolio analysis is shown in Figure 2-4. In 6 of the 10 scenarios, some level of CCCT plants would be cost effective, and in two only CCCT plants are least cost. This is partially due to "lumpiness," i.e., the larger size required for CCCT plants to be cost effective. If we reasonably adjust generic plant sizes to better match the timing of resource needs, for example, frame peakers with firm gas pipeline capacity would be chosen as cost effective in the Base Scenario. CCCT plants performed better in scenarios where the margin (market price minus variable operating cost) from operating CCCT plants is higher, which effectively reduces the cost of the plants. For example, in the Base + High CO_2 Scenario, coal plants are pushed out of the dispatch, driving up power prices relative to natural gas prices so the additional margin from CCCT plants offsets their higher capital cost relative to CTs. In the Base + No CO_2 Scenario, the margin from operating CCCT is again higher, this time because the lack of a CO_2 tax reduces the variable operating cost of CCCT plants enough for the margin to again offset its higher capital cost relative to a CT.

The stochastic analysis demonstrated that including CCCT plants in the mix reduced both cost and risk, and the more other gas resources were displaced, the lower the cost and risk. In fact, the stochastic analysis showed that candidate strategy 4, which added only CCCT plants, would be expected to be about 1.3 percent lower cost over the planning horizon than the chosen resource plan forecast.

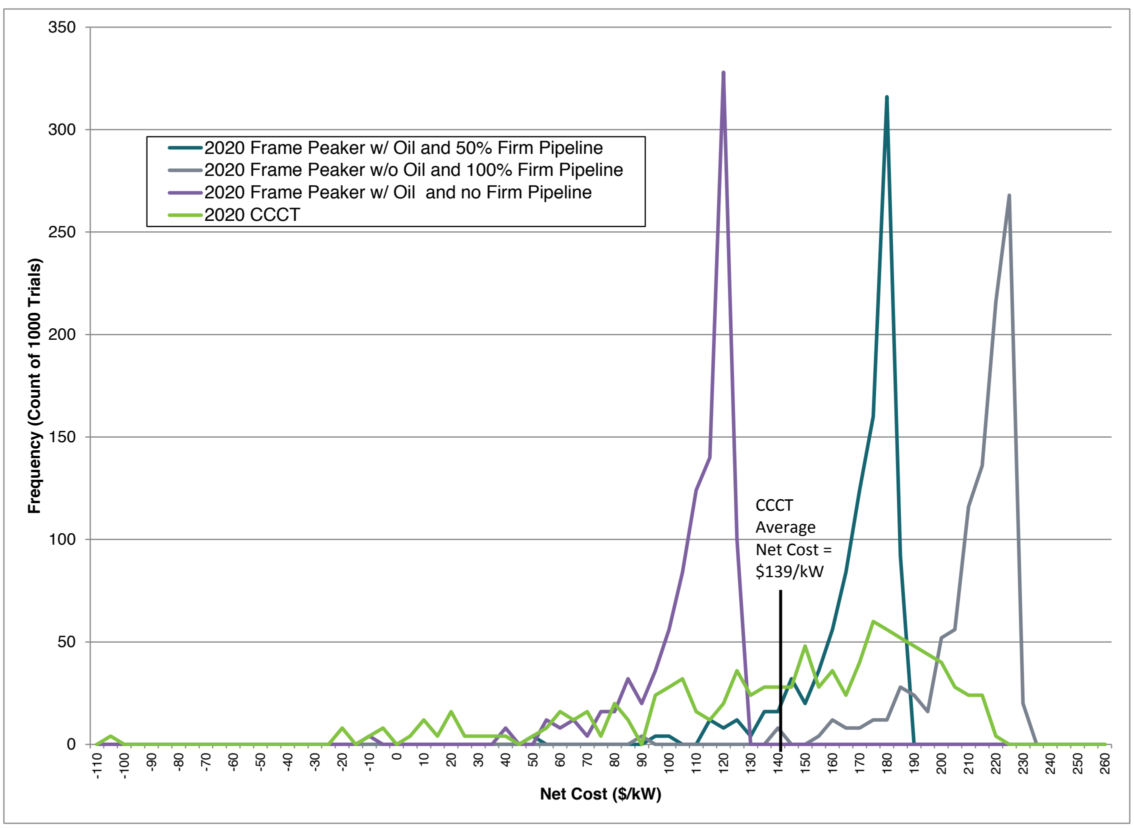
Figure 2-7: Stochastic Analysis Resource Addition Results

NPV ($Millions)	Base Deterministic Portfolio Cost	Difference from Base	Mean	Difference from Base	TVar90	Difference from Base
1 - All Frame Peaker	**12,531**		**11,343**		**14,589**	
2 - Early Recip Peaker	12,620	89	11,782	439	15,014	426
3 - Early CCCT/Thermal Mix	12,729	198	11,392	49	14,412	(177)
4 - All CCCT	12,761	230	10,993	(350)	13,856	(733)
5 - Mix CCCT & Frame Peaker	12,627	96	11,138	(205)	14,147	(442)

Why Include Frame Peakers in Resource Plan? There were two compelling reasons for adding frame peakers to the resource plan, one quantitative, the other qualitative. Qualitative concerns relate to the impact of technology changes, especially with respect to reciprocating engines, and energy policy uncertainty.

Quantitatively, analysis demonstrated that the net cost for frame peakers was lower than CCCTs if firm pipeline capacity is not needed, and since we are confident that at least one or two additional frame CTs could be sited and permitted with backup fuel and adequate air permits, the resource plan should reflect addition of these resources.[7] Figure 2-8, below, compares the distribution of net generation costs[8] of CCCT plants with three sets of assumptions for frame CTs. The middle distribution that resembles a spike represents the frame peakers with firm pipeline capacity to cover 12 run-hours (50% firm pipeline). The CCCT distribution is much more spread out, and its mean is clearly to the left of the frame peaker distribution. This shows that if sizing were irrelevant, CCCT would be lower cost, consistent with the results for candidate strategies 4 and 5. However, when firm pipeline capacity is not needed, the net cost for frame peakers shifts significantly to the left and is clearly less than the expected value for CCCT.

Figure 2-9: CCCT and Peakers with Oil Backup,
Comparison of Net Cost Distribution in the Base Scenario (in 2016 dollars per kW)



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7 / *Chapter 6 presents a comprehensive analysis demonstrating that back-up fuel for existing dual-fuel units is sufficient—firm pipeline capacity does not appear to be needed.*
8 / *Net generation cost is calculated by subtracting the operating margin (electric price minus variable operating cost) calculated hourly, in each simulation from the fixed cost of the plant.*

Resources Not Selected

The following summarizes expectations for some alternative resources that were not selected for the electric resource plan.

Energy Storage. This is a very broad category, that can include smaller scale resources like batteries, up to 1000 MW pumped hydro storage. Continuing to improve our analytical capability to economically value flexibility will help better value those aspects of these resources. However, even the very high relative flexibility value assigned to batteries in our flexibility sensitivity analysis did not show those resources being cost effective. This may change in the future as technology continues to reduce cost of utility scale batteries. Pumped hydro did not appear cost effective on a generic basis, but it is possible that developers will participate in PSE's anticipated all-source RFP, so we will be able analyze these resources on a specific basis, which may show they are more cost effective than we found in the IRP.

Montana Wind. Montana wind generally has high capacity factors and higher peak capacity value than Northwest wind, but generally does not meet the legal requirements under RCW 19.285 as a qualifying renewable resource, because they are outside the defined geographical boundaries. This IRP demonstrated that if the capacity contribution of Montana wind is high enough, it may be able to overcome the transmission cost to bring Montana wind to PSE. It is possible that developers may have specific transmission solutions that are less costly than our generic assumptions in the IRP. If specific Montana wind resource alternatives are bid into the all-source RFP process, they will be rigorously analyzed along with the other resource alternatives.

Utility Scale Solar. The cost of solar continues to decline. It is possible that utility scale solar will become more cost effective than wind in the Northwest. Our need for renewables to comply with RCW 19.285 is still 8 years away. We will continue to monitor trends as technology drives down the cost of all resources.

Reciprocating Engines. These resources provide significantly faster response than other types of thermal resources. In the flexibility sensitivity, the value of that flexibility appeared to compensate for the higher upfront cost of these resources. The challenge with these resources, however, is that they may have a difficult time meeting particulate emission limits – the requirements are site specific. Engineering innovations may overcome this challenge in the future – we will continue to monitor those developments.

GAS SALES RESOURCE PLAN

Resource Additions Summary

The gas sales resource plan is summarized in Figure 2-9, followed by a discussion of the reasoning that led to the plan. (Information on the analysis of gas for generation fuel can be found in Chapter 6.)

Figure 2-9: Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

Base Scenario MDth/day	2018-19	2022-23	2026-27	2030-31	2034-35
Demand-side Resources	12	29	46	58	69
PSE LNG Peaking Project	69	85	85	85	85
Swarr Upgrade	30	30	30	30	30
NWP/Westcoast Expansion	-	34	49	102	102
Mist Storage Expansion	-	-	50	50	50
Cross Cascades to AECO Expansion	-	-	10	10	10
Cross Cascades to Malin Expansion	-	-	-	99	99
NWP/KORP Expansion	-	-	-	-	-
Total	111	178	270	434	445

The gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. The additions identified above are consistent with the optimal portfolio additions produced for the Base Scenario by the SENDOUT gas portfolio model analysis tool. SENDOUT is a helpful tool, but results must be reviewed based on judgment, since real world market conditions and limitations on resource additions are not reflected in the model.

Gas Sales Results across Scenarios

As with the electric analysis, the gas sales analysis examined the lowest reasonable cost mix of resources across a range of ten scenarios. Figure 2-10 illustrates the lowest reasonable cost portfolio of resources across those potential future conditions.

Figure 2-10: Gas Sales Portfolios by Scenario (MDth/day)

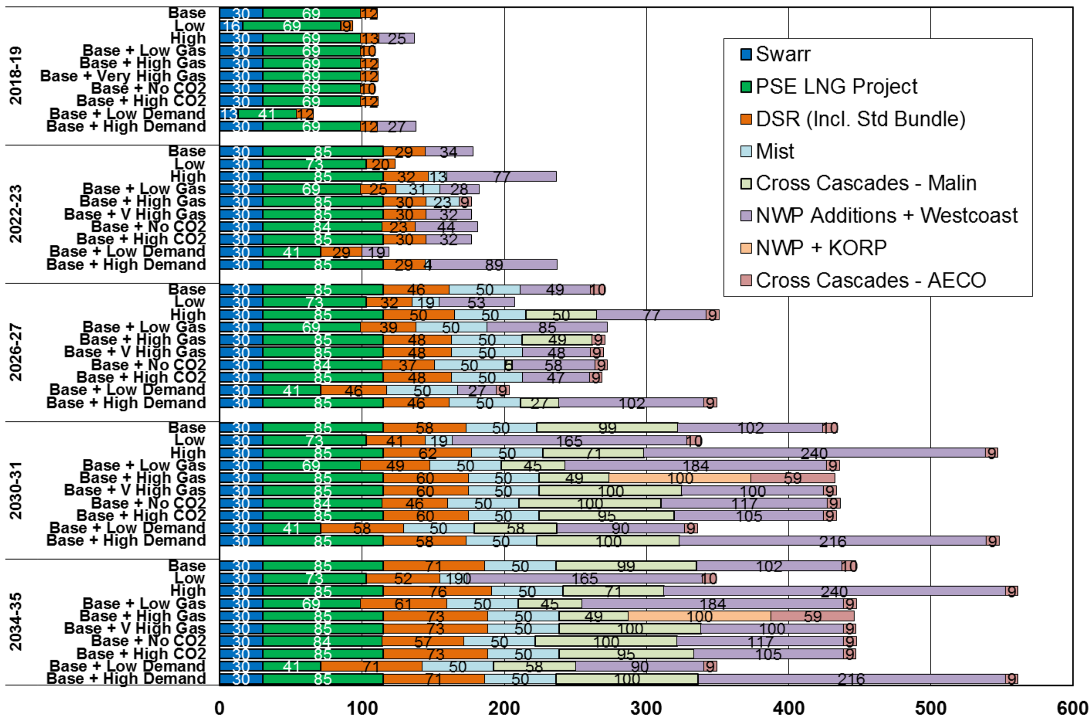


Figure 2-12, above, shows that results across scenarios are consistent. The full Swarr upgrade is cost effective in all scenarios by the 2022-23 winter period and a similar level of DSR is cost effective across all scenarios. In 6 out of 10 scenario/sensitivities, 100% of the PSE LNG Project was found to be cost effective—at least some of that resource was cost effective in all 10 scenario/sensitivities. The peak day capacity of the PSE LNG Project chosen varies in four of the scenarios, but this is a function of the SENDOUT model's limitations, since the capacity of the LNG project is not flexible, as discussed in more detail in Chapter 7, Gas Analysis. Also, the Mist storage with prospective pipeline capacity on Northwest pipeline (NWP) from Portland to Seattle is selected in most scenarios beginning in 2026, though this resource availability is dependent on expansion of the NWP. The remaining gas sales resource need is filled with varying amounts of pipeline volumes to either the Station 2 hub on the Westcoast pipeline or to the Malin hub via the possible Cross-Cascades pipeline. Later in the planning horizon, results vary mostly because of long-term load growth projections. Different elements of the resource plan are discussed below.

Demand-side Resource Additions

DECISION. PSE will include gas DSR consistent with results from the Sendout model for the Base Scenario results.

SUMMARY. Cost-effective DSR levels vary slightly across scenarios. By the 2022-23 heating season, the difference between the High Scenario[9] (at 32 MDth per day) and the Low Scenario[10] (at 20 MDth per day) is only 12 MDth per day. Even the addition of a carbon tax in the Base Scenario had an impact of only 7 MDth per day by the 2022-23 heating season since it still selected 29 MDth of DSR and the Base + No CO_2 Scenario selected 23 MDth per day. Given the small range, it is reasonable to adopt the level of conservation from the Base Scenario of 29 MDth per day by 2022-23 growing to 69 MDth per day by 2034-35 or the resource plan.

FACTORS THAT COULD AFFECT DECISION. There should be little impact in the near term level of planned DSR, since PSE works with the CRAG to develop conservation targets based on these IRP results. Longer-term, technology changes or policies could impact conservation targets in future IRPs.

Supply-side Resource Additions

Swarr Upgrade

DECISION. Preliminary work necessary to upgrade the facility's environmental safety and reliability systems and increase production capacity to 30,000 Dth per day should proceed with the goal to ready this resource for availability for the 2016-2017 winter.

SUMMARY. All of the scenarios selected the Swarr upgrade project early in the study period (by 2018). Upgrades to increase deliverability to the 30 MDth per day design level are low cost relative to other resource alternatives. The Swarr upgrade has been selected consistently in PSE IRP analyses, and the company will begin implementing this upgrade, as reflected in the Action Plan.

FACTORS THAT COULD AFFECT DECISION. This is a very near-term action item. PSE is ready to begin construction. Aside from unexpected issues in implementing the upgrades, little will impact this decision.

9 / The High Scenario had High CO2 prices.
10 / The Low Scenario had zero CO2 prices.

PSE LNG Peaking Project

DECISION. Include the PSE LNG Peaking Project facility in the resource plan, starting at 69 MDth per day and ramping up to 85 MDth per day as PSE's distribution system is built out to accept the full withdrawal capacity.

SUMMARY. PSE's planned PSE LNG Project, located in Tacoma, will provide peaking supplies for our gas sales customers as well as LNG as a transportation fuel. SENDOUT optimization analysis illustrated in Figure 2-10, shows the PSE LNG Project is a cost-effective peaking supply across all scenarios. The small variation in optimal plant sizes is primarily related to SENDOUT modeling limitations because in optimization mode, SENDOUT assumes resources can be scaled linearly, meaning 75% of the plant would only cost 75% of the full cost. That logic does not apply to an asset-based resource like the PSE LNG Project. Additional analysis of the portfolio benefits of the PSE LNG Project discussed in Chapter 7 demonstrates the PSE LNG Project would be cost effective in every scenario.

FACTORS THAT COULD AFFECT DECISION. PSE is in the late development stage of the LNG peaking project in Tacoma. Our final decision will be based on the receipt of all major project permits, and take into account regulatory and other business considerations, taken as a whole.

DISCUSSION. Some level of capacity from the PSE LNG Project appears cost effective in every scenario. In four cases, the SENDOUT optimization analysis showed less than the full 85 MDth per day would be cost effective, but additional analysis demonstrated that the full capacity would be cost effective in all scenarios. In optimization mode, the SENDOUT model uses a simplifying assumption that optimal sizing is possible and that the relationship between capacity and cost is linear. Since the costs of the LNG project do not vary linearly with capacity, additional analysis was necessary to understand the tradeoffs of including or excluding LNG across the different scenarios.

For each scenario, we ran another set of analyses. In one, the LNG Peaking Project was included in the portfolio at 85 MDth per day, and in the other the project was excluded. The results quantify the net benefit (or cost) to customers in each scenario. Figure 2-11, below, demonstrates that the NPV benefits to customers of the LNG Peaking Project range from $8.4 million to $103 million, with the Base Scenario showing a savings to customers of almost $98 million. Given the 85 MDth per day LNG Peaking plant is a least cost resource in every scenario, it was included in the resource additions forecast.

Figure 2-11: Portfolio Benefits From PSE LNG Peaker

	Gas Portfolio Costs Net Present Value ($000s)		
SCENARIO	FULL LNG	NO LNG	(Benefit) / Cost of LNG
BASE	$ 9,366,925	$ 9,464,726	$ (97,801)
LOW	$ 6,257,998	$ 6,294,659	$ (36,661)
HIGH	$ 12,963,307	$ 13,052,452	$ (89,146)
BASE + LOW GAS	$ 8,212,622	$ 8,263,903	$ (51,281)
BASE + HIGH GAS	$ 10,719,839	$ 10,823,632	$ (103,794)
BASE+VERY HIGH GAS	$ 11,906,047	$ 11,994,805	$ (88,758)
BASE+NO CO2	$ 7,775,728	$ 7,846,172	$ (70,444)
BASE+HIGH CO2	$ 10,465,655	$ 10,565,404	$ (99,748)
BASE+LOW DEMAND	$ 9,031,721	$ 9,040,101	$ (8,379)
BASE+HIGH DEMAND	$ 10,450,532	$ 10,550,911	$ (100,379)

Mist Storage and Pipeline Expansions

DECISION. Continue to consider resource additions from the Base Scenario for expanded NWP pipeline capacity and Mist storage that occur later in the planning horizon. Improve the analytical process to better reflect variability in prices between gas market hubs.

SUMMARY. These further-out decisions do not need to be made at this time, allowing PSE time to further refine our risk analysis. There is an important relative risk to consider when acquiring long-term pipeline capacity versus market area storage. Acquiring pipeline capacity generally locks in supply pricing to a specific basin, whether it may be in Northern British Columbia at Station 2, in Alberta at AECO or in the Rockies at Malin. Prices between these basins have changed over time for a variety of reasons, some of which may or may not be present in the future. Market area storage, such as Mist, avoids the risk of locking in price levels to any specific basin – gas conservation programs have the same benefit. In PSE's 2017 IRP, we will focus on improving this risk analysis to better support specific resource decisions.

FACTORS THAT CAN AFFECT DECISIONS. Two sets of factors could affect these decisions.

1. ***New Market Entrants.*** Utilities could find themselves taking a back seat in future pipeline expansion decisions if methanol plants or LNG export facilities enter the market because the gas infrastructure needs of those industries are so significant. That is, if a large methanol manufacturing facility on the I-5 corridor contracts with Northwest Pipeline and Westcoast to go to Station 2, gas utilities will only have a choice of whether or not to join; there will not be enough market share to build an expansion in another direction. Such new players could also create opportunities to acquire peaking resources if their production processes do not require the same degree of firm physical deliveries as the utility industry.

2. ***Relative Prices Between Basins.*** Sometimes the spread in market gas prices between different basins can be large enough to cover the fixed cost of a pipeline expansion. For example, if market gas prices in the Rockies relative to Station 2 fall by $2.00 per MMBtu, that may be sufficient to cover a higher pipeline cost to the Rockies. Market area storage, like Mist, helps to avoid some of that risk because there may be sufficient flexibility to fill the storage resource during off-peak seasons. This is a risk where PSE will focus during the next IRP process.

PLANNING ENVIRONMENT

Contents:

These are the conditions that defined the planning context for the 2015 IRP.

REGIONAL RESOURCE ADEQUACY

The long-term load/resource studies developed by the region's major energy organizations, NPCC, PNUCC and BPA,[1] differ in some details, but most of the forecasts point in the same direction: The current Pacific Northwest (PNW) energy and capacity surplus will cross over to deficit at some point in the next decade – unless new resources are developed. Based upon current information, and assuming that all independently owned generation will be available to serve peak PNW loads, the region will transition from a winter peak surplus of 1,975 MW in 2016 to a winter peak deficit of 3,110 MW in 2025.[2]

For more than a decade, the region's surplus has kept wholesale market power and capacity prices low, and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation. Currently, PSE relies on more than 1,600 MW of wholesale market purchases to meet winter peak obligations,[3] but now that the planning environment is changing, this strategy needs to be re-evaluated. The financial and physical risks of continuing such a high degree of reliance on wholesale market purchases in deficit conditions are substantial.

Two factors are of particular concern in relying on the wholesale market to meet winter peak power demand: 1) the physical availability of wholesale power; and 2) rising prices as the supplies grow scarcer. Under certain conditions described in the regional forecasts, it is possible that there may not physically be enough energy and capacity available within the Pacific Northwest – even including spot market imports from California – to meet all of the region's winter firm loads. So, one or more PNW load-serving entities would be forced to curtail service to customers. Since PSE is one of the largest – if not *the* largest – purchaser of winter capacity in the region, PSE's customers would be particularly exposed during regional curtailment events, because large portions of the energy and capacity that PSE was counting on to purchase may simply not be available.

1 / The Northwest Power and Conservation Council (NPCC or the Council), the Pacific Northwest Utilities Conference Committee (PNUCC) and the Bonneville Power Administration (BPA). These studies are included in Appendix F, Regional Resource Adequacy Studies.
2 / Based on information provided in PNUCC's 2015 Northwest Regional Forecast and BPA's 2014 Pacific Northwest Loads and Resources Study. The cited figures include firm imports from California, but do not include other short-term imports that may be available. These studies are included in Appendix F, Regional Resource Adequacy Studies.
3 / See Chapter 6, Electric Analysis, for more detail on wholesale market purchases and peak need.

Certain characteristics of the WECC (Western Electricity Coordinating Council) wholesale marketplace also contribute to the risk profile in deficit conditions. Three are particularly important: 1) Many transactions are financially firm but not physically firm; 2) any wholesale power sale is subject to curtailment; and (3) aside from paying liquidated damages, the non-performing party has no obligation to replace the physical supply of power to the buyer, so the buyer must locate and contract for replacement power. Since prices can rise dramatically in times of scarcity and there are many exceptions to the current WECC wholesale market price cap of $1,000 per MWh, PSE could be subject to very high costs to meet load and reserve obligations.

Appendix G, Wholesale Market Risk, discusses the risks associated with the wholesale electric market exposure in more detail.

CONVERGENCE OF GAS AND ELECTRIC MARKETS

The increasing use of natural gas for electric generation has also increased awareness of the need for coordination between the two industries. Both sectors and several government agencies are working to address the growing interdependence and avoid a crisis. Generally, two aspects of the convergence are attracting concern: operational issues and long-term planning.

Operational Issues

The gas and electric markets have different trading days and hours, and this presents significant obstacles to coordination. Gas markets conduct business on a standard nationwide "gas day." Regional electric markets conduct business on a calendar-day basis, and they also operate in hourly and sub-hourly increments. This mismatch between trading days and hours creates challenges for electric generation operators who are trying to line up supply across time zones.

In 2014, FERC published a Notice of Proposed Rulemaking (Docket No. RM14-2), in which it proposed an aggressive set of changes to the timing of the gas day and scheduling of natural gas intended to improve coordination between the gas and electric industries. In response, the two industries came together under the guidance of the NAESB (North American Energy Standards Board) and recommended adoption of an expanded and better-coordinated daily gas nomination schedule and no change to the gas day. While FERC had proposed the change in the gas day in an effort to improve access to gas supplies in certain organized markets, the vast majority of the gas industry participants and many electric generating interests opposed the change. FERC, in its Order No. 809,[4] dated April 16, 2015, adopted the NAESB proposed gas nomination schedule and accepted NAESB's recommendation to leave the gas day unchanged. PSE was actively engaged in the NAESB gas day/gas scheduling process and remains heavily involved in ongoing regional and national efforts to facilitate better gas/electric coordination.

Another operational challenge is the need for gas and electric industries to coordinate communication and actions in emergency situations. PSE has led the effort to address this issue through development of the Northwest Mutual Assistance Agreement (NMAA). The NMAA provides for communication among regional gas utilities and power generators during emergency situations on the gas system, and it tests this capability periodically.

4 / *http://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf*

Long-term Planning Challenges

In addition to the conditions outlined in the Regional Resource Adequacy section above, gas-electric convergence issues are also having an impact on long-term resource planning. These have to do with the increasing strain on the gas infrastructure system as higher and higher volumes of natural gas move through it. Two issues in particular cause concern: available pipeline capacity and volatility.

Available Pipeline Capacity. Some power generators and industrial end-users have come to rely upon the availability of less-expensive interruptible[5] pipeline capacity to economically transport gas for generation fuel and industrial process uses. Interruptible capacity has been plentiful for many years, as the market "grew into" the capacity expansion that went into service in 2003. But, as demand increases for natural gas to serve both gas customer growth and electric generation fuel needs, less interruptible pipeline capacity is available. Available pipeline capacity will shrink as a result, and interruptible users may have to make different, and more costly, commitments to firm pipeline capacity in order to maintain reliable service. According to the Northwest Gas Association (NWGA) 2015 Gas Outlook, "under the expected and high demand cases, peak day loads could stress the system, approaching or exceeding the region's infrastructure capacity within the forecast horizon".[6] To meet incremental demands, expanded pipeline capacity will be needed in some locations. See Chapter 7, Gas Analysis, for a more detail on PSE's gas pipeline capacity position.

The Western Interstate Energy Board's State-Provincial Steering Committee (SPSC) formed the Western Gas-Electric Regional Assessment Task Force to examine this issue across the WECC,[7] and the PNUCC and NWGA have also developed a Power and Natural Gas Planning Task Force to monitor the situation.[8]

5 / Interruptible capacity on a fully-contracted pipeline results from a firm shipper not fully utilizing its firm rights on a given day. This unused (aka: interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day.
6 / http://www.nwga.org/2015-natural-gas-outlook/
7 / Materials from the SPSC's Task Force are available at http://westernenergyboard.org/natural-gas/study/
8 / Additional information on the PNUCC/NWGA Power and Gas Task Force is available at http://www.pnucc.org/system-planning/power-natural-gas-taskforce

Volatility. The growing use of peaking generation plants that ramp up and down hourly to balance fluctuations in load and intermittent resources presents another challenge. As demand for natural gas to fuel this type of rapid-deployment generation increases, it can create large swings in gas loads on the interstate pipeline system. This has the potential to strain the entire supply chain, including upstream pipeline and processing capacity.

Both of these conditions make the availability of firm gas storage an increasingly important resource to consider when building portfolios.

GAS SUPPLIES AND PRICING

Natural gas supplies continue to exceed expectations due to the abundant supply of natural gas from shale formations and improving production techniques. Although gas supplies have continued to grow, gas supply development has begun to slow in the face of current over-supply, low prices and the dip in oil price. As stated in the NWGA 2015 Gas Outlook, "While natural gas prices will likely continue to be vulnerable to volatility and spikes during periods of very high demand (as was seen during the winter of 2013/14), they are not expected to return to the sustained high price environment of a few years ago." [9]

Long-term projections of natural gas's affordability continue to augment the role of natural gas in our region's environment and economy. Natural gas remains a good economic value as an energy source, especially compared to its price levels of just a few years ago and the price of substitute fuels like oil. This remains true even in the current environment of lower-priced oil.

Pipeline Transportation and Storage

Though the gas transportation system is adequate to meet current demand, it is likely to experience increasing stress as more and more of the region's electric generation requires natural gas for fuel, as liquefied natural gas (LNG) exports materialize, as large industrial uses such as methanol plants are developed, and as the transportation sector[10] begins to adopt natural gas as an attractive fuel option. Significant additions of gas peak loads will certainly require expanded pipeline capacity for certain locations (see Chapter 7, Gas Analysis). Given the scale of new industrial demand it's important to note that large new industrial gas users may have more control over timing and location of future infrastructure expansions than existing users, including utilities.[11]

9 / http://www.nwga.org/wp-content/uploads/2015/06/2015OutlookWEB.pdf
10 / In this context, transportation sector includes maritime and heavy truck shipping and CNG vehicle use.
11 / Northwest Gas Infrastructure Landscape Looking Forward, a paper produced by NWGA and PNUCC, discusses the development of large industrial gas loads. http://www.nwga.org/wp-content/uploads/2015/07/Northwest-gas-inf-FINAL-Jul-2015-v21.pdf

LNG Storage Opportunity. The 2013 IRP included the development of a mid-scale LNG liquefaction and storage facility as an alternative resource to serve the growing demand for LNG as a marine and vehicle transportation fuel. This LNG facility was selected as a cost-effective resource in the 2013 IRP. In this 2015 IRP, we continue to pursue this alternative and find that building a facility that can serve both core gas customers as well as the needs of transportation fuel customers will enable PSE to reduce the cost of the peaking service to core gas customers. This IRP evaluates building an LNG facility that would serve both needs: 1) provide on-site storage capacity to serve gas customers' peak needs; and 2) supply LNG fuel to serve Puget Sound's marine traffic and the natural gas vehicle market.

Gas for the Transportation Sector

While the market share for alternative-fueled vehicles is currently small, PSE has seen a marked increase during the past few years in the number of natural gas vehicles (NGVs) within the utility's service territory. At the end of 2014, there were over 825 natural gas-fueled vehicles registered in the counties where PSE's natural gas customers live. PSE delivered more than 870 thousand dekatherms of natural gas to NGVs in 2014 – equivalent to the natural gas consumption of about 11,000 homes. In addition, interest in LNG fuel for marine transportation is strong and growing.

Demand for natural gas as transportation fuel is expected to increase over time because of its advantages compared to gasoline and diesel fuels: it is less expensive and produces significantly lower carbon dioxide (CO_2) and nitrogen dioxide (NO_2) emissions. In addition, since the transportation sector is the largest contributor to CO_2 emissions in the state, it can also make a significant contribution to meeting state and federal emission reduction targets.

The relative lack of access to refueling stations is likely inhibiting more widespread NGV adoption in Washington. Similarly, the absence of an LNG supply chain in the Puget Sound area may be hindering ship and ferry conversion from high-cost, high-polluting petroleum fuels to natural gas.

Compressed Natural Gas (CNG). In order to assist customers with financial and technical barriers around compressed natural gas, PSE recently developed and obtained regulatory approval for a service to provide customers with compressed natural gas suitable for use in vehicles at the customer's site.

SYSTEM FLEXIBILITY

Balancing reserves and contingency reserves are the two components of PSE's flexibility need.

Balancing Authority Challenges

As a Balancing Authority (BA), PSE must retain enough operational flexibility to keep the system in balance as demand and supply vary from moment to moment. These fluctuations happen continually and are caused by a wide variety of events, from morning demand spikes to the need to compensate for wind generation when winds drop below minimum velocity, and from unplanned generator outages to scheduled energy interchanges. The flexible capacity used to manage this variability is called balancing reserves. In addition to balancing reserves, PSE must also (like other Balancing Authorities) carry capacity that is capable of responding to infrequent but significant regional events (as when a large generator suddenly fails); these are called contingency reserves.

Flexibility needs are met by dispatching resources that can immediately change their output levels to match changes in load or other resources' increase or decrease in generation. Specific characteristics such as how quickly a resource can synchronize to the PSE system, minimum and maximum operating range and ramp rates determine the flexible capacity available from a given resource.

Currently, the company's share of Mid-Columbia hydroelectric assets provides most of PSE's balancing and contingency reserves; however, PSE's share in these assets has declined in recent years due to expiring contracts. PSE now relies on natural gas turbines more frequently for balancing reserves. The move to thermal resources to meet flexibility needs and the increase in intermittent wind generation in PSE's Balancing Authority area impacts both portfolio costs and operations.

Appendix H, Operational Flexibility, discusses the portfolio's ability to effectively balance load and wind fluctuations and describes the related economic analysis.

Energy Imbalance Market

To help address operational flexibility needs, PSE is scheduled to join the voluntary, within-hour Energy Imbalance Market (EIM) operated by the California Independent System Operator (CAISO) effective October 1, 2016.

The current energy market in the Pacific Northwest is structured around hourly energy products traded among entities on a bilateral basis. This structure allows BAs to balance their systems on an hourly, forward-looking basis. But, because there is no liquid market for energy within each operating hour, BAs must rely on their own generating resources within the hour to continuously match changes (or imbalances) in load and generation. To accomplish this, they may have to dispatch a relatively high-cost resource while a neighboring entity has a lower cost resource they would be willing to dispatch if a market were available. Also, the within-hour flexibility needs of all of the region's BAs increases as intermittent resources like wind generate more and more of the region's electricity.

The EIM provides another tool for reliably and economically maintaining balance between electric demand and resource generation. BAs will continue to transact day-ahead and hour-ahead to balance their forecasted load; then, ahead of the operating hour, participating BAs may voluntarily bid their excess generating resources into the market. The EIM Market Operator will integrate all bids into its Security Constrained Economic Dispatch (SCED) software, which will settle and clear on both a 15-minute and a five-minute basis the imbalances across the entire EIM footprint.

By considering the operational needs and available resources from multiple BAs, this market results in lower cost, more efficient dispatch of resources and allows BAs to collectively manage their individual imbalances. From a system flexibility perspective, the EIM can reduce the cost of procuring and deploying flexible resources and potentially reduce the amount of balancing reserves BAs must hold.

ENVIRONMENTAL REGULATION

PSE's generating facilities are subject to a wide range of environmental regulations established by state and federal governments and administered by their agencies. Among the significant Washington state laws are RCW 80.80, which restricts emissions to a level that precludes development of new coal resources in the state, and RCW 70.235.020, which commits the state to reduce greenhouse gas emissions to 1990 levels by 2020. Other environmental regulations that affect PSE operations include:

- Section 111(b) of the Clean Air Act
- Section 111(d) of the Clean Air Act
- Coal Combustion Residuals regulated under the Resource Conservation and Recovery Act
- The Mercury and Air Toxics Standard
- The Clean Water Act
- The Regional Haze Rule (Montana)
- National Ambient Air Quality Standards
- Washington State's Carbon Dioxide Mitigation Program
- Proposed Washington Clean Air Rule.

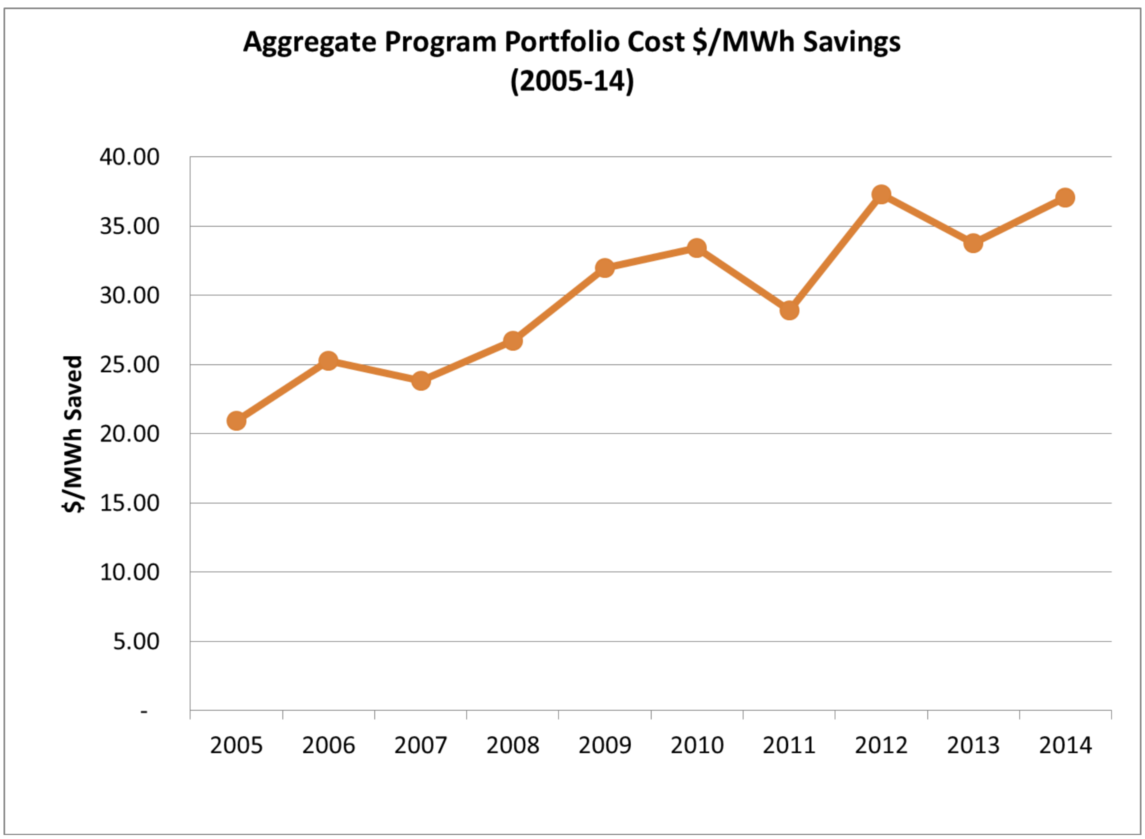
All of these regulations are discussed in more detail in Appendix C, Environmental and Regulatory Matters.

DEMAND-SIDE RESOURCES

While energy efficiency programs are still able to achieve savings targets in the slow-growth aftermath of the financial crisis, a number of shifts and trends specific to the energy industry are affecting how programs are delivered, how information is used to create new programs and the development of delivery networks. Among these shifts and trends are lower natural gas prices, the migration of digital technology and data into energy efficiency applications, rapid improvements in and adoption of LED lighting, the end of the federal energy efficiency credits, new federal appliance standards and changing consumer behavior in energy consumption.

As these shifts are taking place, the cost of acquiring demand-side resources is also rising steadily. Figure 3-1 shows the historical trend. Despite a recent dip, this upward movement is likely to continue because as the "easier," low-cost measures get captured in earlier cycles, the cost of capturing marginal units of savings increases. Newer technological solutions are often more costly, and inflation also contributes to rising costs.

Figure 3-1: Cost of Demand-side Resources



Declining gas prices combined with the increasing costs are compromising the cost-effectiveness of some program areas, especially for some of the more expensive gas measures. This has led to re-examination of those measures and to the development of new approaches to bringing cost-effective technologies to market. One example is an on-going collaboration with the Northwest Energy Efficiency Alliance (NEEA). Along with other regional utilities, PSE helped to start this gas collaborative, whose goal is to pool resources and use NEEA's expertise in energy efficiency markets to introduce commercially available technologies that hold the promise of significant savings, but that have not yet been adopted in the Pacific Northwest. Such collaborative investments may open markets to new cost-effective gas programs in the future.

RENEWABLE PORTFOLIO STANDARDS (RPS)

Washington state's RPS (RCW 19.285) requires that a specific portion of electricity provided by a utility be from renewable resources; specifically 3 percent of load by 2012, 9 percent by 2016 and 15 percent by 2020. PSE has met the 2012 RPS requirement to provide 3 percent of load with renewable resources and is on track to meet the 2016 and 2020 RPS requirements.

The company's RPS need is expressed in units called renewable energy credits (RECs). To model the RPS need for this IRP, PSE tested how different load levels affected our need for RECs. Additionally, the RPS allows for REC banking within specified time periods. This analysis assumes a REC banking strategy, which pushes the need for RECs later into the planning period relative to not banking. The REC banking strategy used here is a representative strategy, not an official strategy of the company.

The statute that governs RPS requirements also includes a revenue requirement cost cap alternative to acquiring RECs. According to RCW 19.285, all electric utilities in Washington must meet 15 percent of their electric load with eligible renewable resources by 2020. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility shall be considered in compliance with the annual target. Appendix N, Electric Analysis, includes an analysis that demonstrates PSE is expected to remain under the incremental cost cap.

ELECTRIC RESOURCE ACQUISITIONS

The Acquisition Process

The IRP provides a forecast of demand- and supply-side resources that could be used to meet resource needs. When PSE must fill an actual capacity need, it begins an acquisition process in which specific resource decisions must be made in a dynamic environment. In this process, PSE considers the IRP results along with several additional factors. These factors include the actual availability and cost of proposed resources, specific issues related to proposed resources such as the availability of transmission and gas transportation, changing needs and external influences.

A utility can acquire resources in a number of ways: through competitive bids in a request for proposals (RFP) process, by constructing resources, by operating conservation programs or by purchasing power with negotiated contracts.

WAC 480-107-015 outlines the timing of an RFP. Under the WAC, an RFP must be filed if the IRP shows a capacity need within the first three years of the IRP's planning horizon, though PSE can issue an RFP for a need further out than three years. The process unfolds as follows.

PSE issues an RFP to interested parties and posts it on its website. The proposals submitted are evaluated in a two-phase process using these criteria:

- Compatibility with resource need
- Cost minimization
- Risk management
- Public benefits
- Strategic and financial benefits.

Phase 1 screens proposals to eliminate those with high costs, unacceptable risks or feasibility constraints. It uses a quantitative analysis to screen bids and a qualitative analysis to identify fatal flaws. Phase 1 produces a short list of candidates that advance to Phase 2 of the RFP process. In general, proposals on this list have positive economic benefits and no fatal flaws.

Phase 2 is a due diligence process. Input assumptions such as load and gas prices are updated as needed, more extensive quantitative analysis is performed to evaluate resource portfolios using various assumptions, and qualitative analysis is conducted based on the evaluation criteria. Phase 2 produces a list of proposals with the lowest reasonable cost and risk that best meet PSE's identified resource and timing needs.

PSE officers are kept apprised throughout the process, and updates are provided to the company's Energy Management Committee[12] (EMC). When Phase 2 is completed, a short list of proposals is formally recommended to the EMC for approval. PSE then enters negotiations with short-listed counterparties, and if agreements are reached then possible acquisitions are submitted to the EMC and, in some cases, the Board of Directors for approval. If an acquisition is made, PSE requests a prudence determination from the Washington Utilities and Transportation Commission (WUTC) when the company proposes in a rate proceeding to include the new resource's costs in its rate base and revenue requirement.

How Resource Size Is Determined

The capacity and RPS needs are determined in the IRP and updated on an ongoing basis as new information becomes available. The IRP provides a theoretical picture of the future resource portfolio using a range of generic resources that could be used to meet the capacity and RPS needs under different sets of assumptions. The size and cost of each generic resource are based on what is currently available in the market for that type of resource.

An RFP involves evaluating specific proposals submitted by counterparties as well as internally developed proposals for self-build options. In both the IRP and RFP, PSE uses the Portfolio Screening Model (PSM) to optimize PSE's energy portfolio by minimizing total portfolio cost subject to the two constraints of meeting peak capacity need and the RPS requirement. In both the IRP and RFP analyses, new resources are added in blocks to meet load over the 20-year planning horizon, which results in excess capacity when new resources are added. Gradually, this excess capacity decreases as load grows until there is another build requirement driven by peak capacity need. Evaluation of resource alternatives assumes that excess energy and RECs can be sold into the market. A given bid is evaluated based on its impact on total portfolio cost, its ability to meet the capacity and RPS needs, and qualitative factors. Results are re-evaluated as time passes and new information becomes available.

12 / PSE's EMC provides policy-level and strategic direction for the company's energy resource planning, operations, portfolio management and acquisition decisions.

With respect to how large a wind farm should be, PSE must consider multiple factors when deciding how many turbines to install. Factors that influence this decision include:

- **The type and size of turbine.** This impacts the spacing of turbines on the site and the number that can be installed.
- **Geography of the site.** This can dictate how spread out the turbines are, the number of turbines and the amount of infrastructure such as substations, transmission and roads that are required. The equipment is arranged to be as efficient as possible.
- **Schedule.** A short construction period that includes two summers and one winter is preferable to a longer construction period so that the assets can be placed into service as soon as possible.
- **Interconnection agreements.** Transmission requirements can influence the timing and planning for how the work is done.
- **Contracts with counterparties for delivery of materials and construction**. The turbine supply agreement and balance of plant agreements need to be integrated to avoid gaps in the schedule.

A wind farm is planned to be large enough to capture economies of scale while being small enough to have a relatively short construction period. Some of the required infrastructure is the same for a plant ranging from 100 MW to 250 MW, so if the plant is on the larger side, there are economies of scale as fixed costs are spread over greater plant output. Beyond some size threshold, adding turbines would also require additional infrastructure and construction time, thus delaying the in-service date of the assets.

KEY ANALYTICAL ASSUMPTIONS

Contents

This chapter describes the different forecasts, estimates and assumptions that PSE developed to create the scenarios used in this IRP. In the deterministic phase of the IRP analysis, the scenarios enable us to test how resource portfolio costs and risks respond to different sets of assumptions about economic conditions, environmental regulation, natural gas prices and energy policy. The sensitivities change just one variable in the baseline assumptions for portfolio analysis, which allows us to isolate the effect of a single resource on the portfolio. These assumptions help us to consider how different combinations of resources would affect costs, cost risks and emissions.

OVERVIEW

Scenarios and sensitivities play a key role in the deterministic phase of the IRP analysis.

Scenarios allow us to test the impact of different sets of economic conditions on resource strategy. Using deterministic optimization analysis, we identify the least-cost portfolio of demand- and supply-side resources that will meet need, given the set of static assumptions that define the scenario. For this IRP, PSE developed 10 scenarios.

- **THREE FULLY INTEGRATED SCENARIOS** – Low, Base and High – reflect different sets of assumptions for each of three fundamental economic inputs: customer demand, natural gas prices and CO_2 prices.
- **SEVEN ONE-OFF SCENARIOS** start with Base Scenario assumptions and change just one of those three variables to isolate its effect on PSE's resource plans, costs and emissions.

To complete the scenarios, we create wholesale power price assumptions for each one using an Aurora analysis described later in this chapter. Figure 4-1 illustrates the relationship between the fully integrated and one-off scenarios.

Sensitivities start with baseline portfolio assumptions and change a single resource variable. This makes it possible to examine the cost-effectiveness of a given resource, the value it brings to the portfolio, and explore how PSE might need to respond to unexpected changes in resource availability. The sensitivities are summarized in Figure 4-3.

Figure 4-1: Diagram of 2015 IRP Scenarios

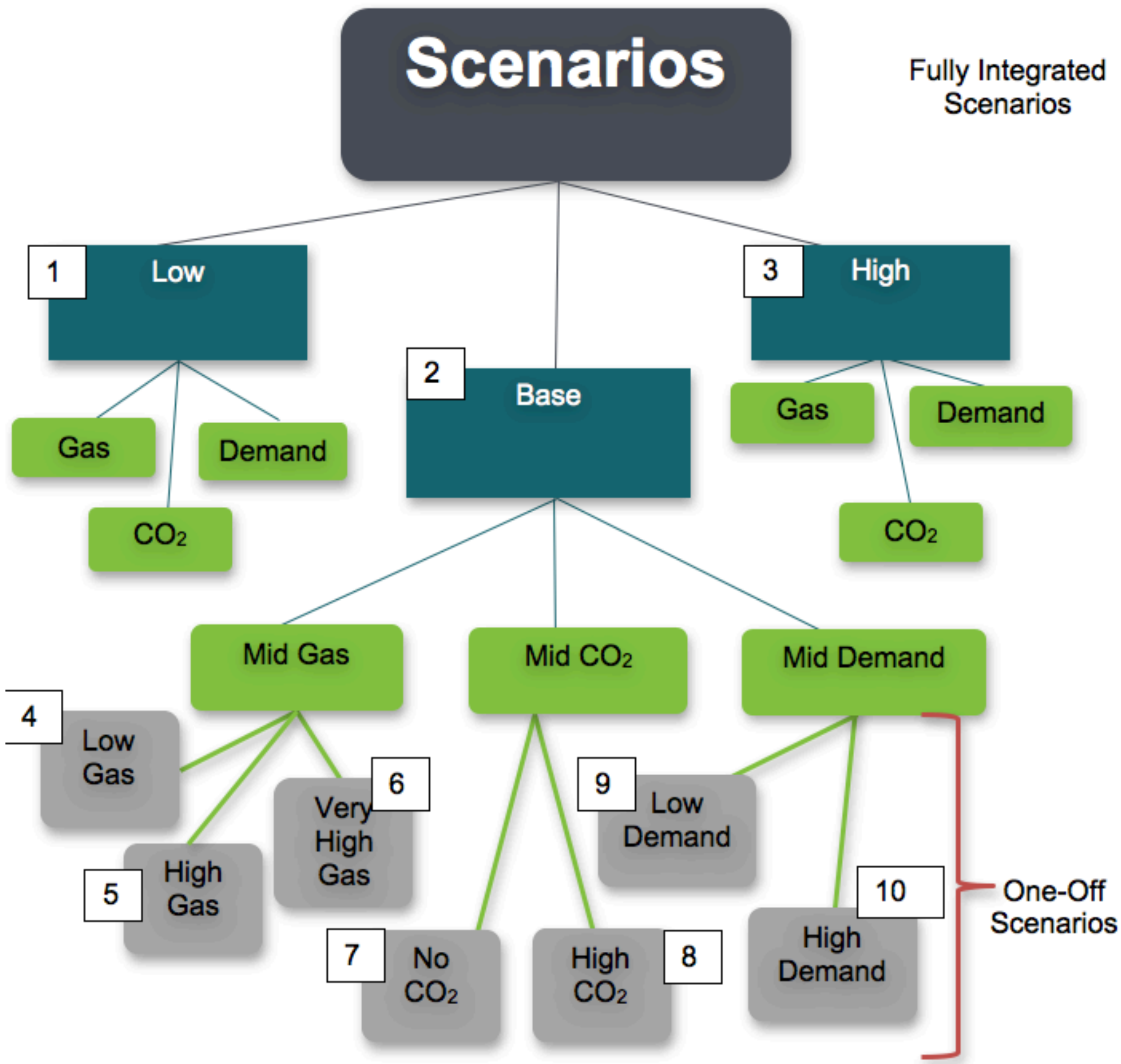


Figure 4-2: 2015 IRP Scenarios

	Scenario Name	Gas Price	CO_2 Price	Demand
1	Low Scenario	Low	None	Low
2	Base Scenario	Mid	Mid	Mid
3	High Scenario	High	High	High
4	Base + Low Gas Price	Low	Mid	Mid
5	Base + High Gas Price	High	Mid	Mid
6	Base + Very High Gas Price	Very High	Mid	Mid
7	Base + No CO_2	Mid	None	Mid
8	Base + High CO_2	Mid	High	Mid
9	Base + Low Demand	Mid	Mid	Low
10	Base + High Demand	Mid	Mid	High

Figure 4-3: 2015 IRP Portfolio Sensitivities

	Sensitivities	Alternatives Analyzed
	Electric Analysis	
A	Colstrip If Colstrip units are retired, what's the most cost-effective way to replace those resources?	*Baseline – All 4 Colstrip units remain in service* 1. Retire Units 1 & 2 in 2026. 2. Retire all 4 units in 2026.
B	Demand-side Resources (DSR) How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements* 1. No DSR. All needs are met with supply-side resources.
C	Thermal Mix How does changing the mix of resources affect portfolio cost and risk?	*Baseline – All peakers selected as lowest cost in the Base Scenario deterministic portfolio.* 1. All CCCT 2. Mix CCCT and frame peaker
D	Gas Plant Location What if the gas plants were built in eastern Washington instead of PSE service territory?	*Baseline – Gas plants located in PSE Service territory* 1. Model gas plants with gas transport costs and transmission costs from eastern Washington.
E	Gas Transport/Oil Backup for Peakers What if peakers cannot rely on oil for backup fuel and must have firm gas supply instead?	*Baseline – 50% firm pipeline capacity with 48 hours of oil backup* 1. 100% firm pipeline capacity with no oil backup
F	Energy Storage/Flexibility What is the cost difference between a portfolio with and without energy storage? How do energy storage resources impact system flexibility?	*Baseline – Batteries and pumped hydro included only if chosen economically* 1. Add 80 MW battery in 2023 instead of economically chosen peaker. 2. Add 80 MW pumped hydro storage in 2023 instead of economically chosen peaker. 3. Add 200 MW of pumped hydro storage in 2023 instead of economically chosen peaker.
G	Reciprocating Engine/Flexibility How do reciprocating engines (recip peakers) affect system flexibility?	*Baseline – Reciprocating peakers modeled at 220 MW with an all-in cost of $1,599 per kW* 1. Model lower capital cost for 75 MW recip peaker. 2. Add 75 MW recip peaker with lower capital cost in 2023. 3. Add 75 MW recip peaker with lower capital cost and flexibility credit in 2023.
H	Montana Wind Update transmission cost for Montana wind to be more optimistic if Colstrip continues to operate. Will MT wind be chosen in lowest cost portfolio?	*Baseline – PSE cost estimate for transmission upgrades to Montana* 1. Lower transmission cost estimate
I	Solar Penetration What if customers install significantly more rooftop solar than expected?	*Baseline – Rooftop solar growth based on current growth forecast trend* 1. Maximum potential capture of rooftop solar
J	Carbon Reduction How does increasing renewable resources and DSR beyond requirements affect carbon reduction and portfolio costs?	*Baseline – Renewable resources and DSR per RCW 19.285 requirements* 1. Add 300 MW of wind beyond renewable requirements. 2. Add 300 MW of utility-scale solar beyond renewable requirements. 3. Increase DSR beyond requirements.

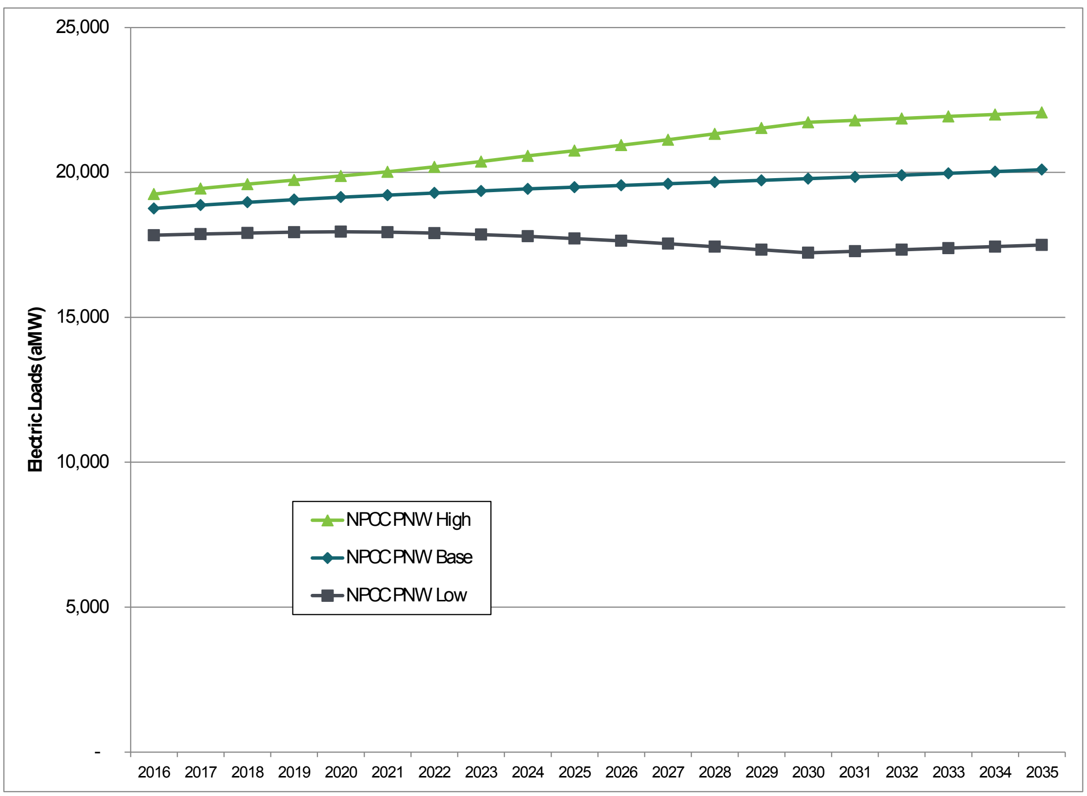
	Sensitivities	Alternatives Analyzed
	Natural Gas Analysis	
A	Alternate Discount Rate Test cost-effective amount of DSR using alternate discount rate to model the value of DSR over time.	*Baseline – Use PSE WACC of 7.77%* 1. Use alternate discount rate of 4.93%.
B	Pipeline Timing Does smoothing out the pipeline capacity expansion change the lowest cost portfolio?	*Baseline – Allow pipeline capacity expansion to be built in 2026 and 2030* 2. Allow pipeline capacity expansion to be built every year starting in 2026

KEY INPUTS

Demand Forecasts

Regional Demand. Regional demand must be taken into consideration, because it significantly affects power prices. This IRP uses the 2013 regional forecast mid-term update developed by the Northwest Power and Conservation Council (NPCC or "the Council").[1] Regional demand is only used in the WECC-wide portion of the Aurora analysis that develops wholesale power prices for the scenarios.

Figure 4-4: NPCC Regional Demand Forecast for Pacific Northwest (PNW)



1 / *The NPCC has developed some of the most comprehensive views of the region's energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.*

PSE Demand. PSE customer demand is the single most important input assumption to the IRP portfolio analysis. The demand forecast is discussed in detail in Chapter 5, and the analytical models used to develop it are explained in Appendix F, Demand Forecasting Models. For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but in reality demand grows faster in some parts of the territory and slower in others.

The three demand forecasts used in this IRP analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period. Significant inputs include information about regional and national economic growth, demographic changes, weather, prices, seasonality and other customer usage and behavior factors. Known large load additions or deletions are also included.

The **2015 IRP BASE DEMAND FORECAST** is based on 2014 macroeconomic conditions such as population growth and unemployment. It is used in the 2015 IRP Base Scenario.

The **2015 IRP LOW DEMAND FORECAST** represents a pessimistic view of the macroeconomic variables modeled in the base forecast. It creates lower demand on the system and is used in the 2015 IRP Low Scenario.

The **2015 IRP HIGH DEMAND FORECAST** is a more optimistic view of the base forecast. It creates a higher demand on the system and is used in the 2015 IRP High Scenario.

Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we need to develop. By the time the IRP is completed, PSE will have updated its demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

The graphs below show the peak demand and annual energy demand forecasts for electric service and gas sales. Both the electric and gas demand forecasts include sales (delivered load) plus system losses. The electric peak demand forecast is for a one-hour temperature of 23° Fahrenheit at SeaTac airport; this is considered the 1-in-2 peak. The gas sales peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport; this is considered the 1-in-20 peak.

Figure 4-5: PSE Electric Peak Demand Forecast (Low, Base, High)

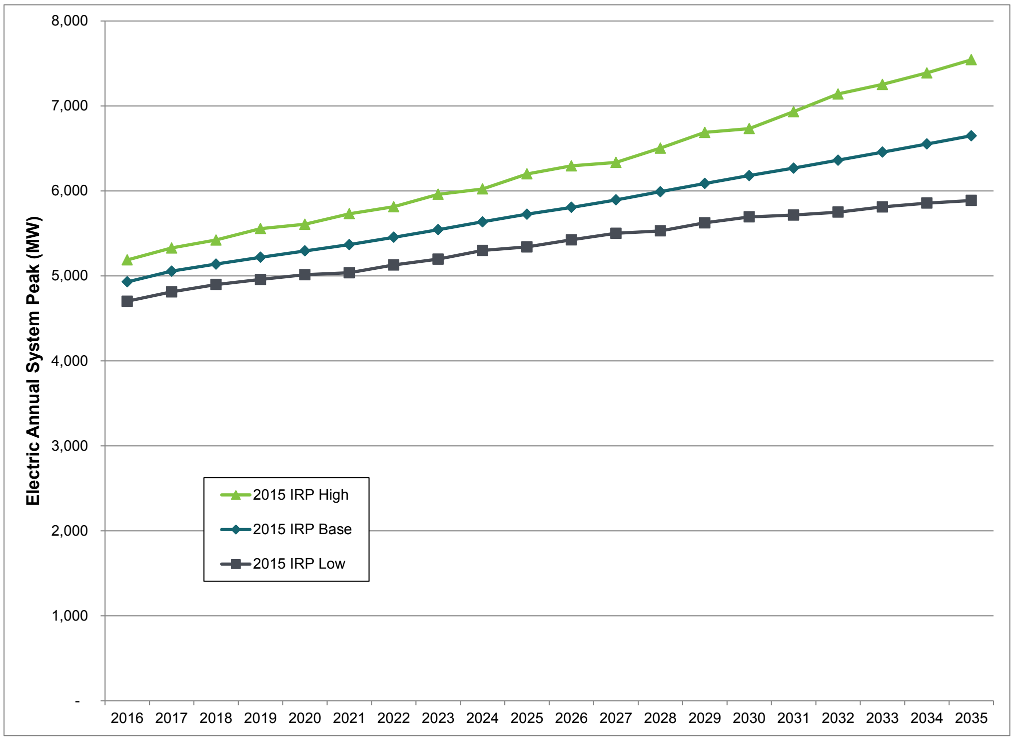


Figure 4-6: PSE Annual Electric Energy Demand Forecast (Low, Base, High)

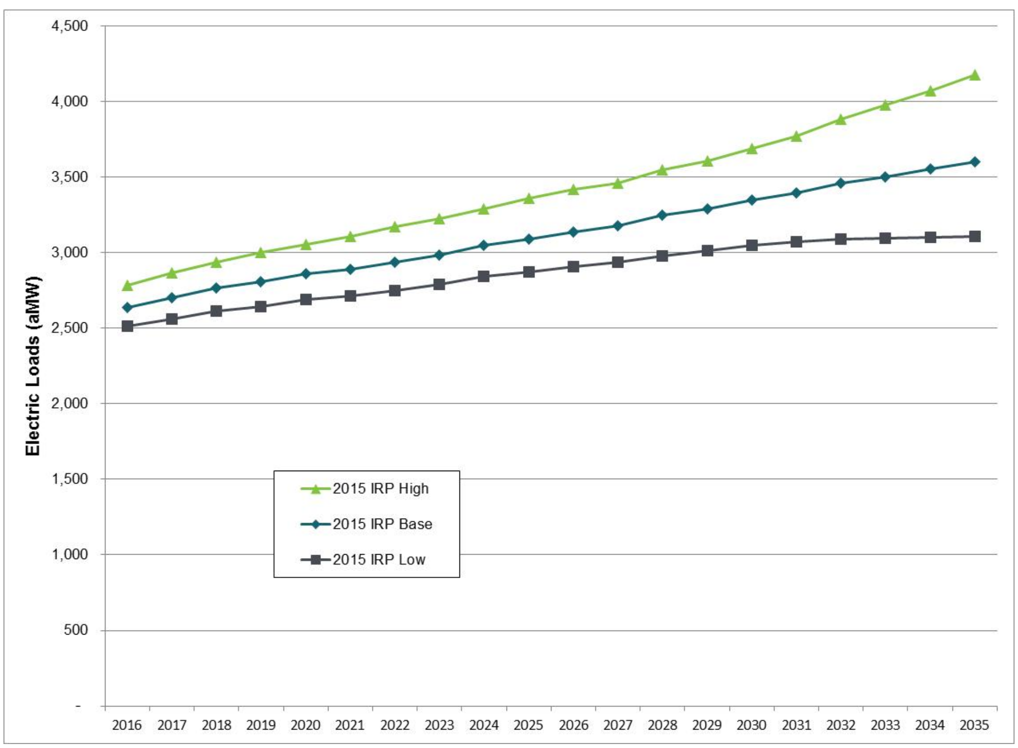


Figure 4-7: PSE Peak Day Gas Sales Demand Forecast (Low, Base, High)

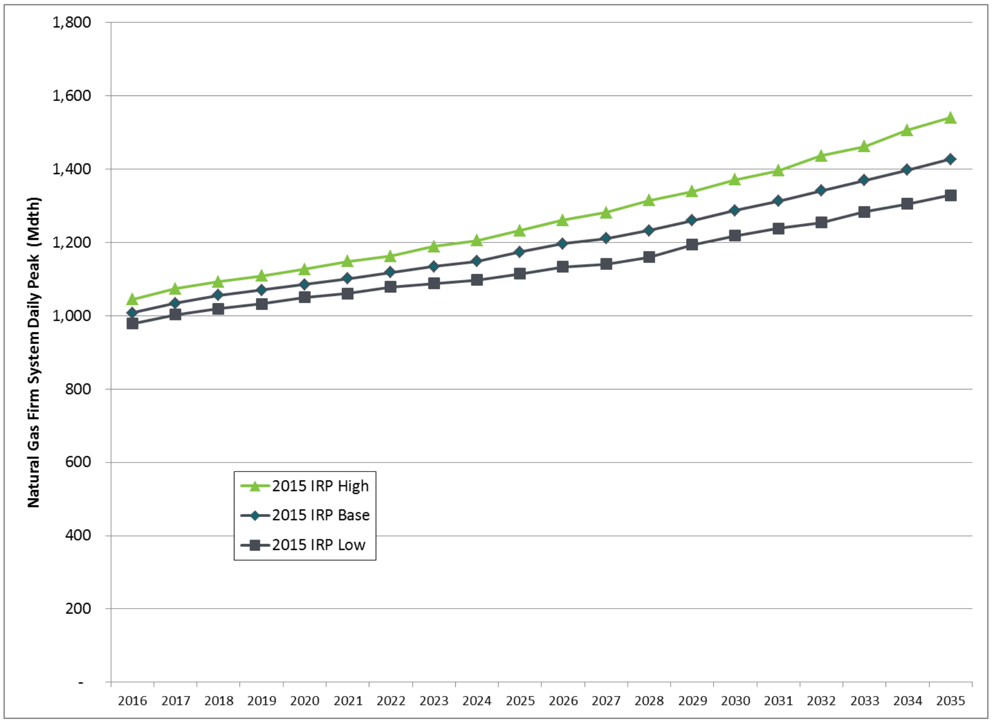
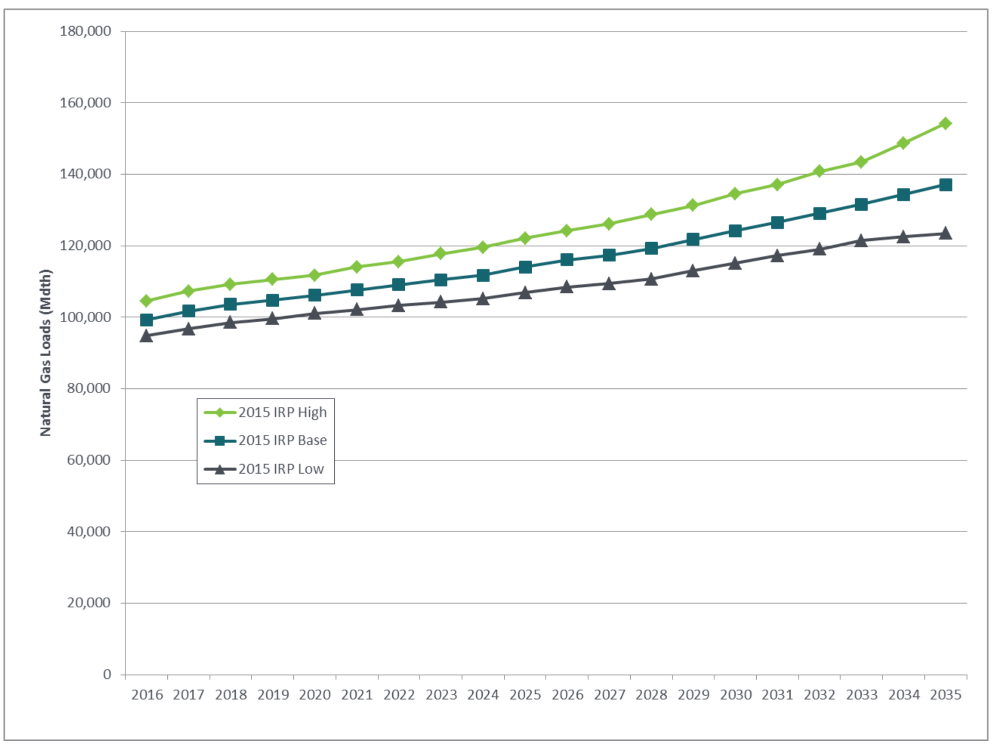


Figure 4-8: PSE Annual Gas Sales Demand Forecast (Low, Base, High)



Gas Prices

For gas price assumptions, PSE uses a combination of forward market prices, fundamental forecasts acquired in November 2014 from Wood Mackenzie, and forecasts developed by the NPCC. Wood MacKenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas (LNG) exports. The NPCC focuses on energy planning issues in the Northwest region. Four gas price forecasts are used in the scenario analysis:

LOW GAS PRICES. These reflect Wood Mackenzie's long-term low price forecast for 2016-2035.

MID GAS PRICES. From 2016-2019, this IRP uses the three-month average of forward marks for the period ending November 14, 2014. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2019, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts. The Base Scenario uses this forecast.

HIGH GAS PRICES. These reflect Wood Mackenzie's long-term high price forecast for 2016-2035.

VERY HIGH GAS PRICES. This forecast reflects the NPCC high gas price forecast developed in July 2014.

Figure 4-9 below illustrates the range of 20-year levelized gas prices and associated CO_2 costs used in this IRP analysis.

Figure 4-9: Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized 2016-2035, nominal $)

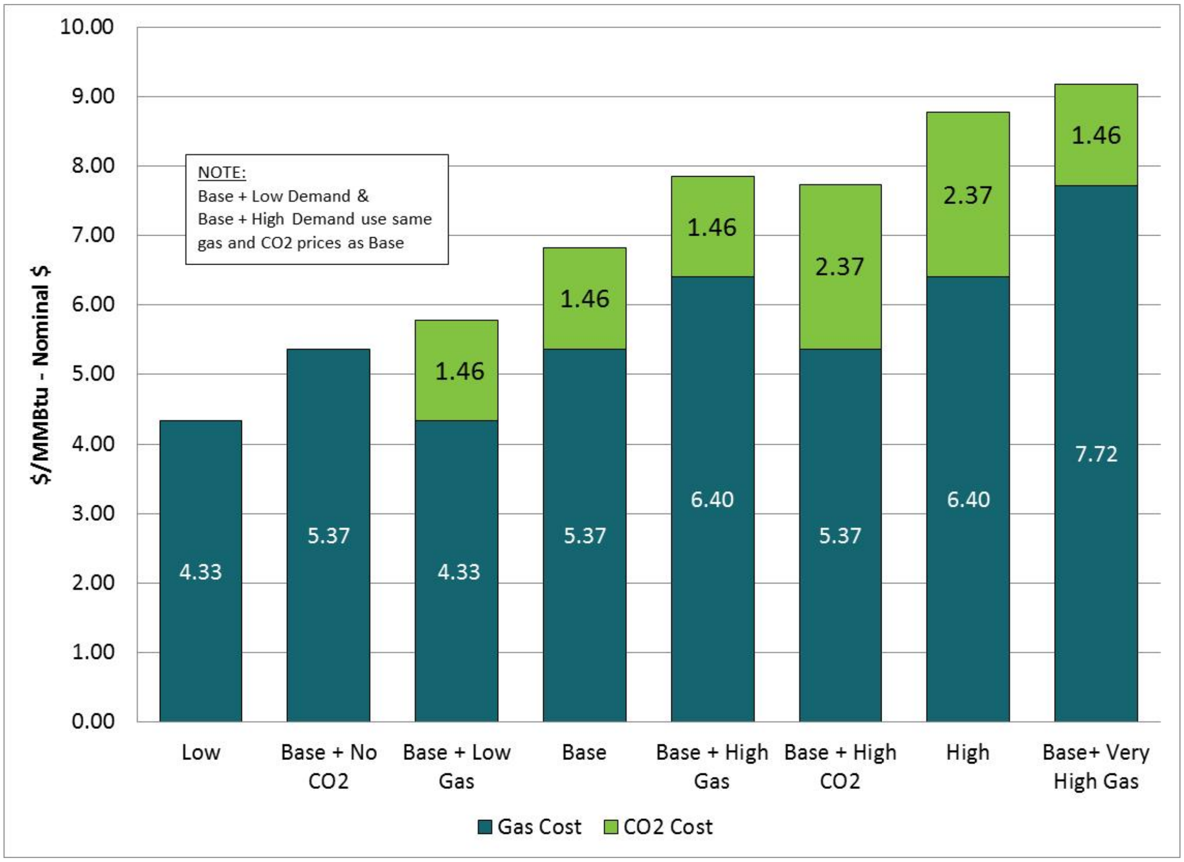
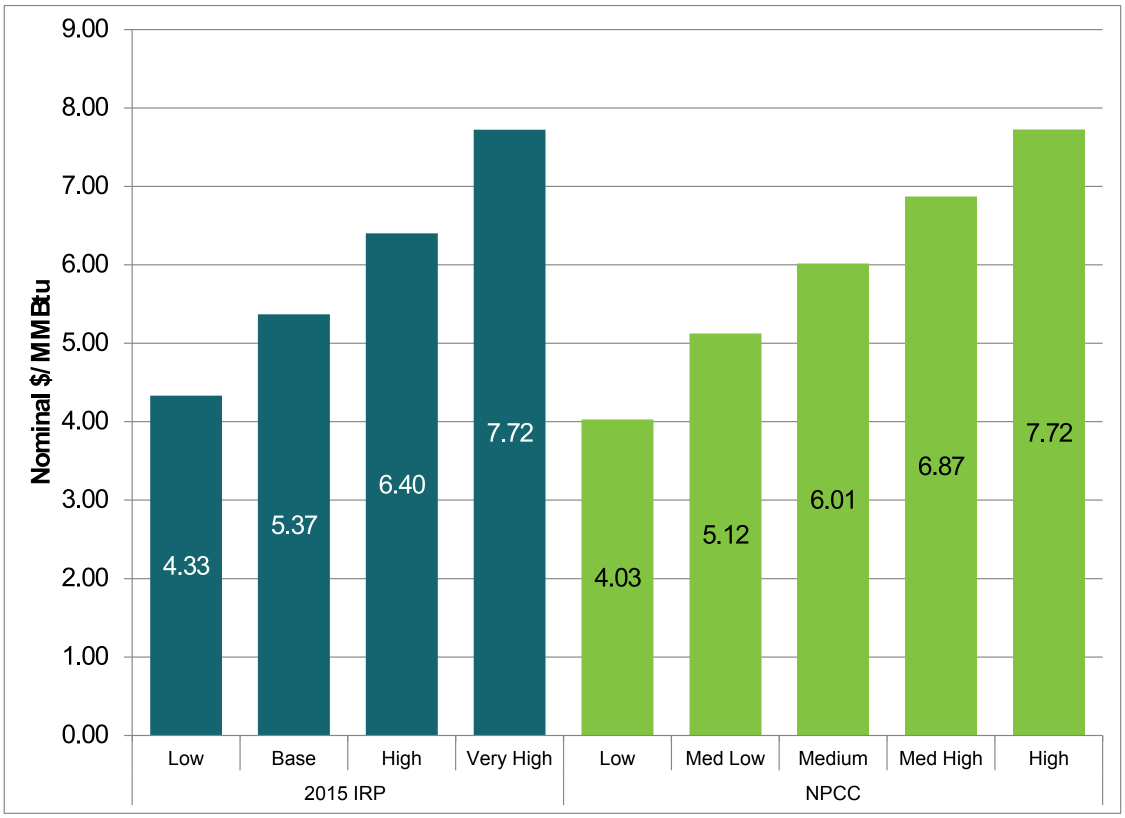


Figure 4-10 below, compares the levelized gas prices PSE used in this IRP with those used by the NPCC in its draft Seventh Power Plan.[2] This illustrates that the range of PSE's gas prices are consistent with the range of gas prices being used by the Council. It also shows PSE's base case is slightly lower relative to the Council's Medium gas price forecast.

Figure 4-10: PSE 2015 IRP Gas Prices Compared to NPCC Seventh Power Plan Gas Prices (adjusted to nominal values)



2 / *PSE's input assumptions use nominal dollars (inflation adjusted) whereas the Council uses real dollar input assumptions (excluding the effects of inflation). Figure 4-10 converts the Council's assumptions to a nominal basis for an apples-to-apples comparison.*

CO_2 Prices

To model uncertainty around CO_2 prices, PSE developed the following estimates as inputs. These estimates reflect the potential for CO_2 price regulation and how that might affect resource decisions, rather than incorporating the societal cost of carbon emissions as an externality. A table showing the annual CO_2 prices modeled can be found in Appendix N, Electric Analysis.

Why model potential carbon price regulation instead of the societal cost of carbon?

By rule the IRP focuses on the costs and benefits that will be experienced by the utility and its customers. Costs and benefits outside of this construct are called externalities. The societal cost of carbon is a difficult externality to model for many reasons. Reducing carbon emissions may benefit society as a whole, but the population of our service territory is only 2.6 million (0.04 percent of the world's population). To reflect the externality impact of carbon reductions to PSE's customers would require either a reasonable estimate of the economic impact on the Pacific Northwest region (which is not available) or prorating the societal benefits that will accrue to our customers only. This highlights the "Tragedy of the Commons" problem associated with climate change, and explains why internalizing these externalities in typical IRP analyses is not a substitute for federal-level carbon regulation policies.

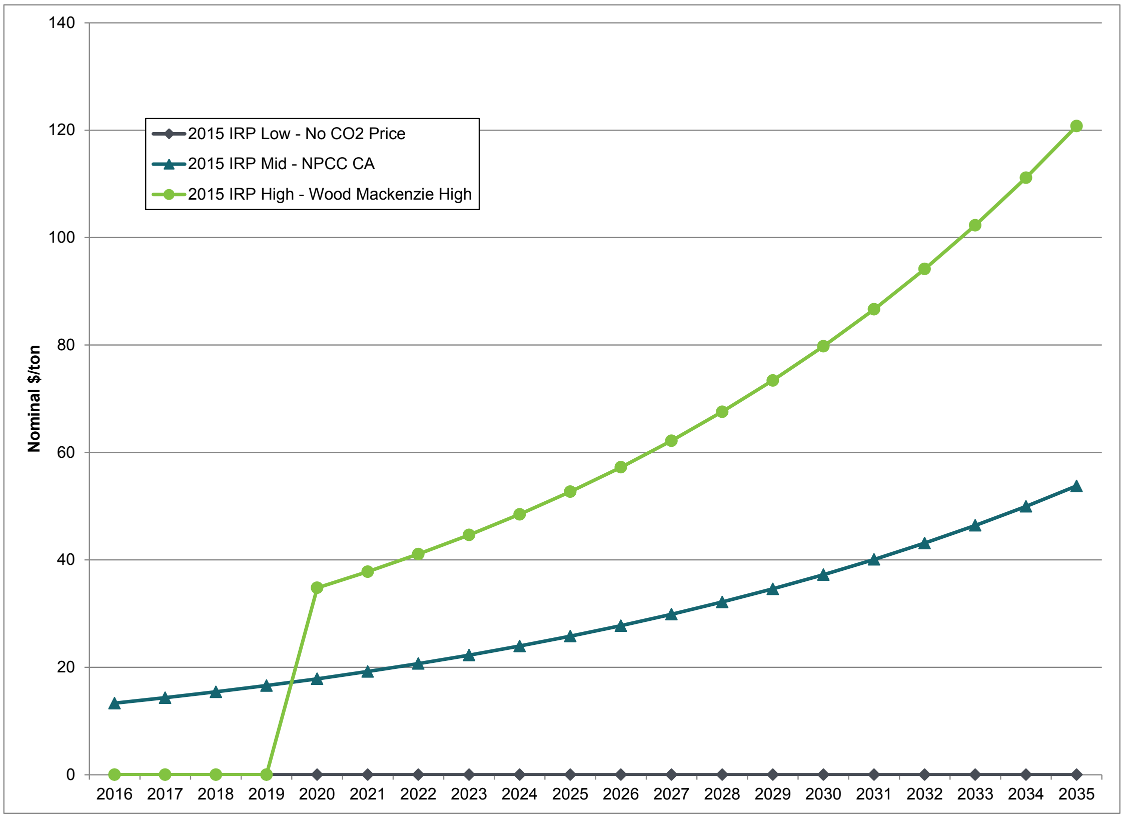
NO FEDERAL CO_2 PRICE. $0 PER TON. The lowest CO_2 price used in the 2015 IRP assumes no federal CO_2 price, but does include an NPCC forecast of California CO_2 prices based on the California Global Warming Solutions Act of 2006 (AB32).[3] This CO_2 price is applied to power plants located in California.

MID CO_2 PRICE. $13 PER TON IN 2016 TO $54 PER TON IN 2035. This estimate is based on NPCC's estimated CO_2 price for California AB32 and is applied as a federal CO_2 price to all resources.

HIGH CO_2 PRICE. $35 PER TON IN 2020 TO $120 PER TON IN 2035. This estimate of federal CO_2 price comes from the Wood Mackenzie high gas price forecast; California CO_2 price are increased to match federal CO_2 price.

3 / See Appendix C, Environmental Matters, for more details on the California Global Warming Solutions Act.

Figure 4-11: Annual Range of CO_2 Prices Used in the 2015 IRP

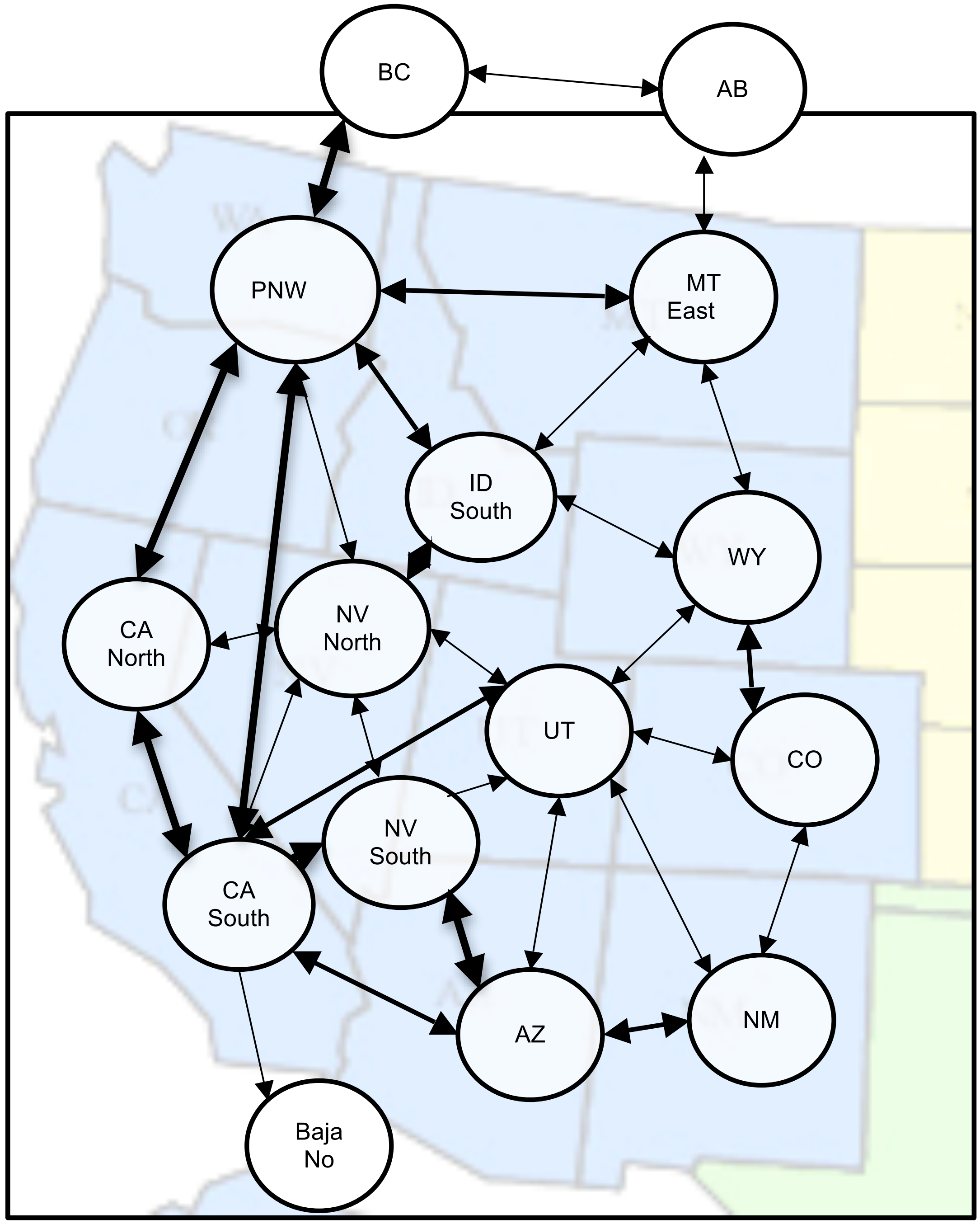


Developing Wholesale Power Prices

A power price forecast is developed for each of the 10 scenarios modeled. In this context, "power price" does not mean the rate charged to customers, it means the price to PSE of purchasing (or selling) 1 megawatt (MW) of power on the wholesale market given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE's resource portfolio.

AURORAxmp is an hourly chronological price forecasting model based on market fundamentals. Creating wholesale power price assumptions requires performing two WECC-wide Aurora model runs for each of the 10 scenarios (Aurora is discussed in more detail in Appendix N, Electric Analysis). The first run identifies needed capacity expansion to meet regional loads. Aurora looks at loads and peak demand plus a planning margin, and then identifies the most economic resource(s) to add to make sure that all regions modeled are in balance. Results of the capacity expansion run are included in Appendix N, Electric Analysis. The second Aurora run produces hourly power prices. A full simulation across the entire WECC region simulates power prices in all 15 zones shown in Figure 4-12 below. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another.

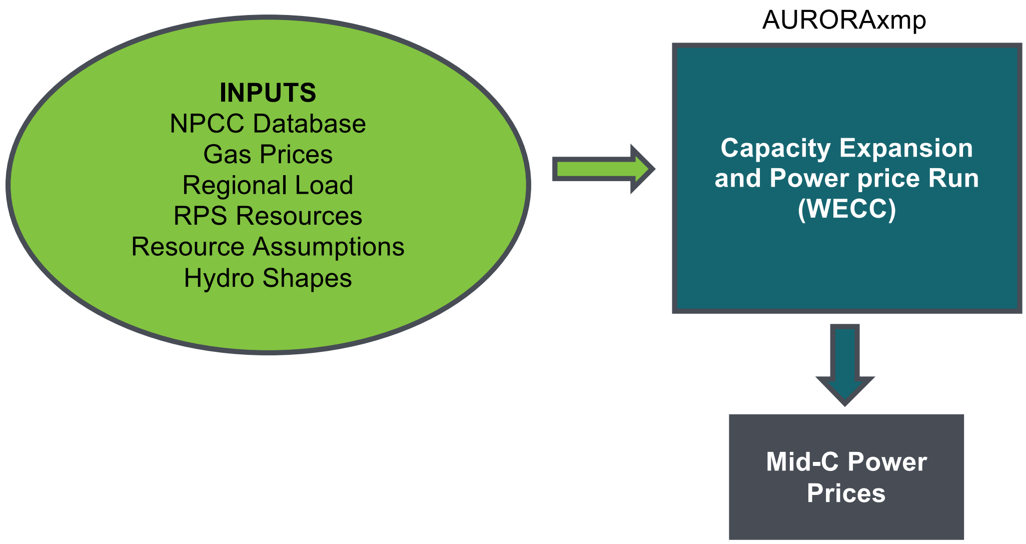
Figure 4-12: Aurora System Diagram



The Pacific Northwest (PNW) Zone is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, Northern Idaho and Western Montana.

Figure 4-13 illustrates PSE's process for creating wholesale market power prices.

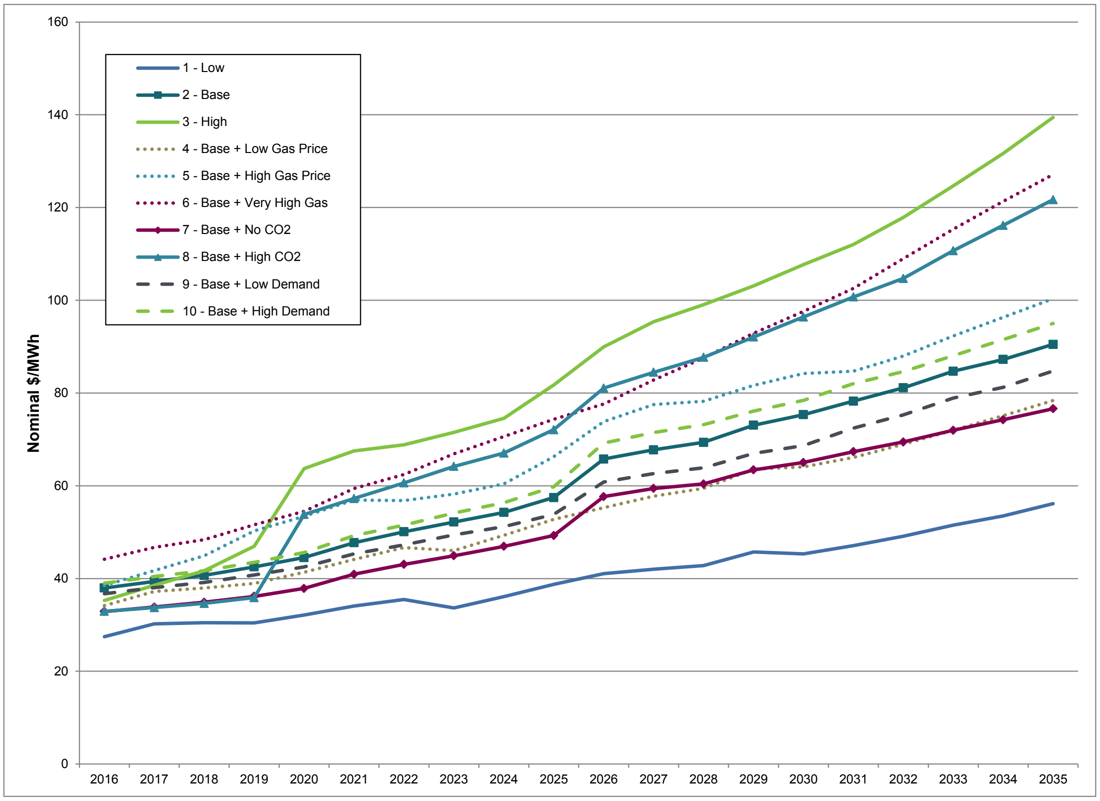
Figure 4-13: PSE IRP Modeling Process for Aurora Wholesale Power Prices



The database of inputs for Aurora started with inputs and assumptions from the NPCC from spring 2014. PSE then included updates such as Natural Gas prices, Resource assumptions, CO2 prices, and inflation. Details of the inputs and assumptions for the Aurora database are included in Appendix N, Electric Analysis

Figure 4-14 shows the 10 power prices produced by the 10 scenario conditions.

Figure 4-14: Input Power Prices by Scenario,
Annual Average Flat Mid-C Power Price (nominal $/MWh)



SCENARIOS AND SENSITIVITES

The scenarios developed for the IRP enable us to test portfolio costs and risks in a wide variety of possible future conditions using deterministic optimization analysis. Sensitivities enable us to isolate the effects of an individual variable on resource portfolios**.** The full range of scenarios is described first, followed by a description of the baseline assumptions that apply to all scenarios.

Fully Integrated Scenarios

Three fully integrated scenarios model a complete range of key indicators: customer demand, natural gas prices and CO_2 prices.[4]

1. Low Scenario

- This scenario models weaker long-term economic growth than the Base Scenario. Customer demand is lower in the region and in PSE's service territory. The NPCC low growth rate is applied for the WECC region, and the 2015 IRP Low Demand Forecast is applied for PSE.
- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.
- No federal CO_2 price is applied, but California CO_2 prices per AB32 are included.

2. Base Scenario

- The Base Scenario applies the NPCC 2013 regional demand forecast to the WECC region and the 2015 IRP Base Demand Forecast for PSE.
- Mid Gas Prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.
- Mid CO_2 prices are modeled: $13 per ton in 2016 to $54 per ton in 2035, plus California CO_2 prices per AB32.

3. High Scenario

- This scenario models more robust long-term economic growth, which produces higher customer demand. The NPCC high growth rate is applied for the WECC, and the 2015 IRP High Demand Forecast is applied for PSE.
- Natural gas prices are higher as a result of increased demand, so the high gas price assumptions are modeled (Wood Mackenzie long-term high forecast for 2016-2035).
- High CO_2 prices are modeled: $35 per ton in 2020 to $120 per ton in 2035, plus California CO_2 prices are increased to match federal CO_2 prices.

4 / *See Figures 4-1 and 4-2.*

One-off Scenarios

Seven one-off scenarios start with the Base Scenario and change just one of the three key conditions.

4. Base + Low Gas Price

This scenario models the impact of a weak long-term gas price by applying the Wood Mackenzie's long-term low gas price forecast to Base Scenario assumptions.

5. Base + High Gas Price

This scenario models the impact of a higher long-term gas price by applying the Wood Mackenzie long-term high gas price forecast for 2016-2035 to Base Scenario assumptions.

6. Base + Very High Gas Price

This scenario models a future in which gas prices are extremely high; it applies the NPCC high gas price forecast to Base Scenario assumptions.

7. Base + No CO_2

This scenario removes federal CO_2 prices from Base Scenario assumptions, but retains a CO_2 price for California.

8. Base + High CO_2

This scenario models a future in which CO_2 prices are high; it applies the high CO_2 price estimate ($35 per ton in 2020 to $120 per ton in 2035) to Base Scenario assumptions.

9. Base + Low Demand

This scenario models low customer demand in the context of Base Scenario assumptions; it applies the 2015 IRP Low Demand Forecast.

10. Base + High Demand

This scenario models high customer demand in the context of Base Scenario assumptions; it applies the 2015 IRP High Demand Forecast.

Baseline Scenario Assumptions – Electric

Baseline scenario assumptions are constant in all scenarios and portfolios and do not change.

Resource Assumptions. PSE modeled the following generic resources as potential portfolio additions in this IRP analysis. (See Appendix D, Electric Resources and Alternatives, for more detailed descriptions of the resources listed here.)

Supply-side resources include the following.

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

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

SIMPLE-CYCLE COMBUSTION TURBINES (FRAME PEAKERS). F-type, wet-cooled turbines are assumed to generate 228 MW and are located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

AERODERIVATIVE COMBUSTION TURBINES (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. Those modeled without oil backup were required to have firm gas supplies and storage.

RECIPROCATING ENGINES (RECIP PEAKERS). This 12-engine design (18 MW each) with wet cooling, is assumed to generate a total of 220 MW and to be located in PSE's service territory.

WIND. Wind was modeled in southeast Washington and central Montana. Washington wind is assumed to have a capacity factor of 34 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 41 percent.

ENERGY STORAGE. Two energy storage technologies are modeled: batteries and pumped hydro. The generic battery resource is lithium-ion technology. Pumped hydro resources are generally large, on the order of 250 to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties.

SOLAR. Utility-scale solar PV is assumed to be located in central to southern Washington, use a fixed tilt system, and have a capacity factor of 20 percent.

Demand-side resources include the following.

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in a lower level of energy being used for doing the same amount of work. These 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 comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

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

DISTRIBUTION 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 that originate from federal and state codes and standards.

For detailed information on demand-side resource assumptions, see Appendix J, Demand-side Resources.

Resource Cost Assumptions. The estimated cost of generic natural gas resources is based on a May 2014 study by Black and Veatch done on behalf of PSE. Renewable resource costs are based on research for estimates in the region and on PSE's experience in the market. The cost curves applied to both of these for the 20-year study period come from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). New equipment costs are assumed to decrease over time. Appendix D, Electric Resources and Alternatives, contains a more detailed description of these assumptions.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes plant, siting and financing costs. PSE's activity in the resource acquisition market during the past ten years informs resource cost assumptions, and our extensive discussions with developers, vendors of key project components and firms that provide engineering, procurement and construction services lead us to believe the estimates used here are appropriate and reasonable.

- Figure 4-15 summarizes generic thermal resource assumptions.
- Figure 4-16 summarizes gas transport costs for CCCTs and peakers with and without oil backup.
- Figure 4-17 summarizes generic renewable resource assumptions.
- Figure 4-18 displays the monthly capacity factor for Washington wind, Montana wind and Washington solar.
- Figure 4-19 summarizes annual capital cost by vintage year for supply-side resources, batteries and pumped hydro storage.

Figure 4-15: Generic Thermal Resource Assumptions

2014 $	Units	CCCT	Frame Peaker w/ Oil	Frame Peaker w/o Oil	Aero Peaker w/ Oil	Aero Peaker w/o Oil	Recip Peaker
ISO Capacity	MW	317	224	224	207	207	220
Winter Capacity	MW	335	228	228	203	203	220
Capacity DF	MW	50					
Capital Cost	$/kW	$1,256	$896	$830	$1,342	$1,273	$1,599
O&M Fixed[5]	$/kW-yr	$10.55	$17.05	$7.24	$16.23	$7.24	$5.31
O&M Variable	$/MWh	$2.96	$2.69	$2.69	$3.50	$3.50	$8.63
Forced Outage Rate	%	3%	3%	3%	3%	3%	3%
Operating Reserves	%	3%	3%	3%	3%	3%	3%
Heat Rate – Baseload HHV	Btu/kWh	6,798	10,046	10,046	9,156	9,156	8,538
Heat Rate – Turndown HHV	Btu/kWh	7,396	14,115	14,115	11,122	11,122	9,431
Heat Rate DF	Btu/kWh	8,670					
Min Capacity	%	50%	40%	40%	25%	25%	4%
Start Time	Minutes	60	29	29	10	10	10
Location		PSE	PSE	PSE	PSE	PSE	PSE
Fixed Gas Transport	$/kW-yr	$63.35	$48.74	$93.62	$44.42	$85.32	$79.57
Variable Gas Transport	$/MMBtu	$0.04	$0.28	$0.04	$0.28	$0.04	$0.04
Fixed Transmission	$/kW-yr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Emissions:							
NO_x - natural gas only	lbs/MMBtu	0.01	0.01	0.01	0.01	0.01	0.02
SO_2 - natural gas only	lbs/MMBtu	0.006	0.006	0.006	0.006	0.006	0.03
CO_2 - natural gas only	lbs/MMBtu	116.0	112.5	112.5	116.0	116.0	114.7
First Year Available		2020	2019	2019	2019	2019	2019
Economic Life	Years	35	35	35	35	35	35
Greenfield Development & Construction Lead time	Years	4	3	3	3	3	3

5 / Units with oil backup include the costs associated with 48 hours of generation using oil priced at $3.00 per gallon.

The natural gas transport costs for gas plants are based on purchasing gas at the Sumas Hub. Resources without oil backup are assumed to need 100 percent firm pipeline transportation plus 20 percent of the daily need in storage; this applies to the CCCT, frame peaker without oil, aero peaker without oil and reciprocating engine. The transportation path is assumed to be Williams Northwest Pipeline (NWP) to Sumas, then Westcoast to Station 2.

For resources with oil backup (the frame peaker and aero peaker), we assume 50 percent firm pipeline transportation on Williams Northwest to Sumas and 50 percent on Westcoast to Station 2, plus 20 percent in gas storage.

The tables in Figure 4-16 summarize the gas transport assumptions for resources with and without oil backup.

Figure 4-16: Gas Transport Costs for CCCT & Peakers

Without Oil Backup – 100% Sumas on NWP + 100% Station 2 on Westcoast

	Fixed Demand ($/Dth/Day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion	0.560	0.030	0.0018	1.9%	3.852%
Westcoast Expansion	0.460	0.010	0.0000	1.6%	3.852%
Storage	0.044	0.000	0.0000	2.0%	3.852%
Total	**1.064**	**0.040**	**0.0018**	**5.5%**	**3.852%**

With Oil Backup – 50% Sumas on NWP + 50% Station 2 on Westcoast

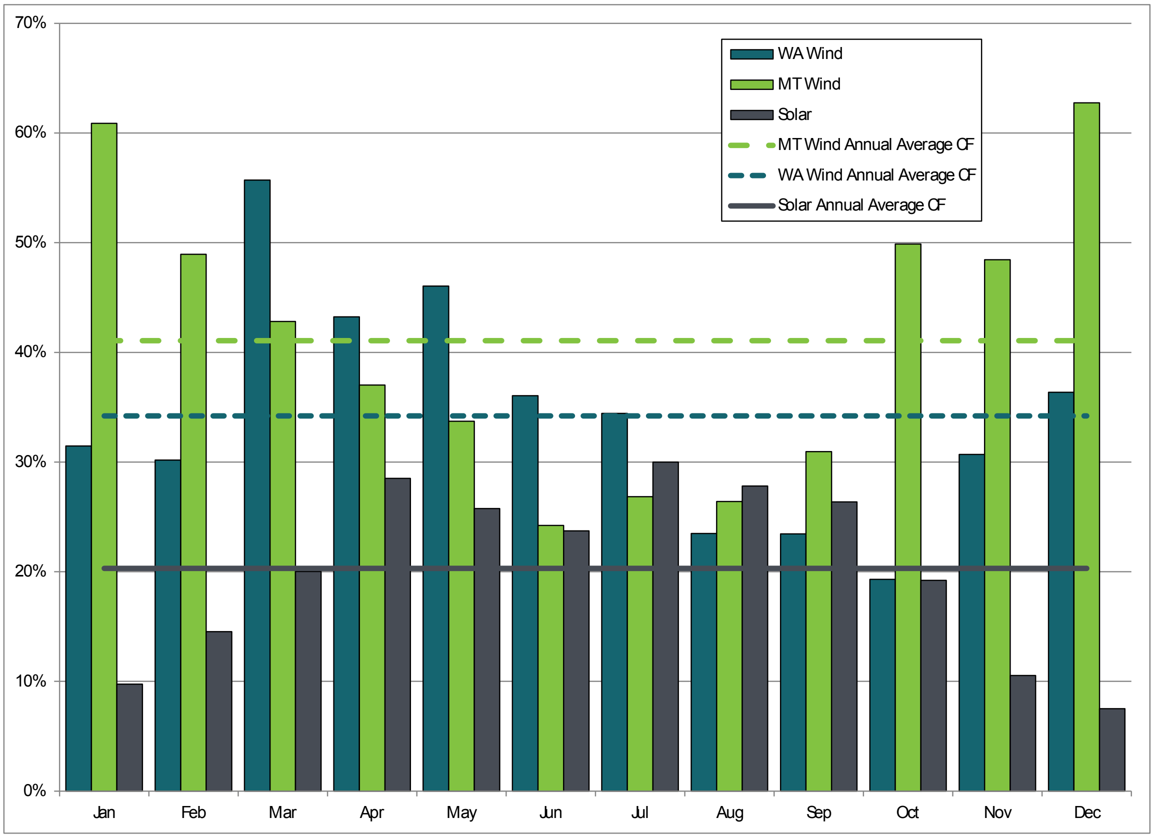
	Fixed Demand ($/Dth/Day)	Variable Demand ($/Dth)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion	0.280	0.131	0.030	0.0018	1.9%	3.852%
Westcoast Expansion	0.230	0.110	0.010	0.0000	1.6%	3.852%
Storage	0.044	0.000	0.000	0.0000	2.0%	3.852%
Total	**0.554**	**0.242**	**0.040**	**0.0018**	**5.5%**	**3.852%**

Figure 4-17: Generic Renewable Resource Assumptions

2014 $	Units	Washington Wind	MT Wind	Battery	Pumped Storage Hydro	Biomass	Solar
Nameplate Capacity	MW	100	100	80	200	15	20
Winter Capacity	MW	8	55	80	200	0	0
Capital Cost	$/kW	$1,968	$4,659	$1,498	$2,400	$4,322	$2,535
O&M Fixed	$/kW-yr	$27.12	$27.12	$7.71	$15.00	$110.98	$17.47
O&M Variable	$/MWh	$3.15	$3.15	$0.00	$0.00	$5.53	$0.00
Capacity Factor	%	34%	41%			85%	20%
Capacity Credit	%	8%	55%	100%	100%	0%	0%
Total Hours Discharge	Hours			2	10		
Location		SE WA	Central MT	PSE	WA/OR	West WA	Central WA
Fixed Transmission	$/kW-yr	$35.23	$55.05	$0.00	$20.83	$20.83	$23.35
Variable Transmission	$/MWh	$1.84	$1.84	$0.00	$0.34	$0.34	$1.84
First Year Available		2019	2020	2019	2030	2019	2019
Economic Life	Years	25	25	20	60	35	25
Greenfield Development & Construction Lead time	Years	3	3	3	15	3	3

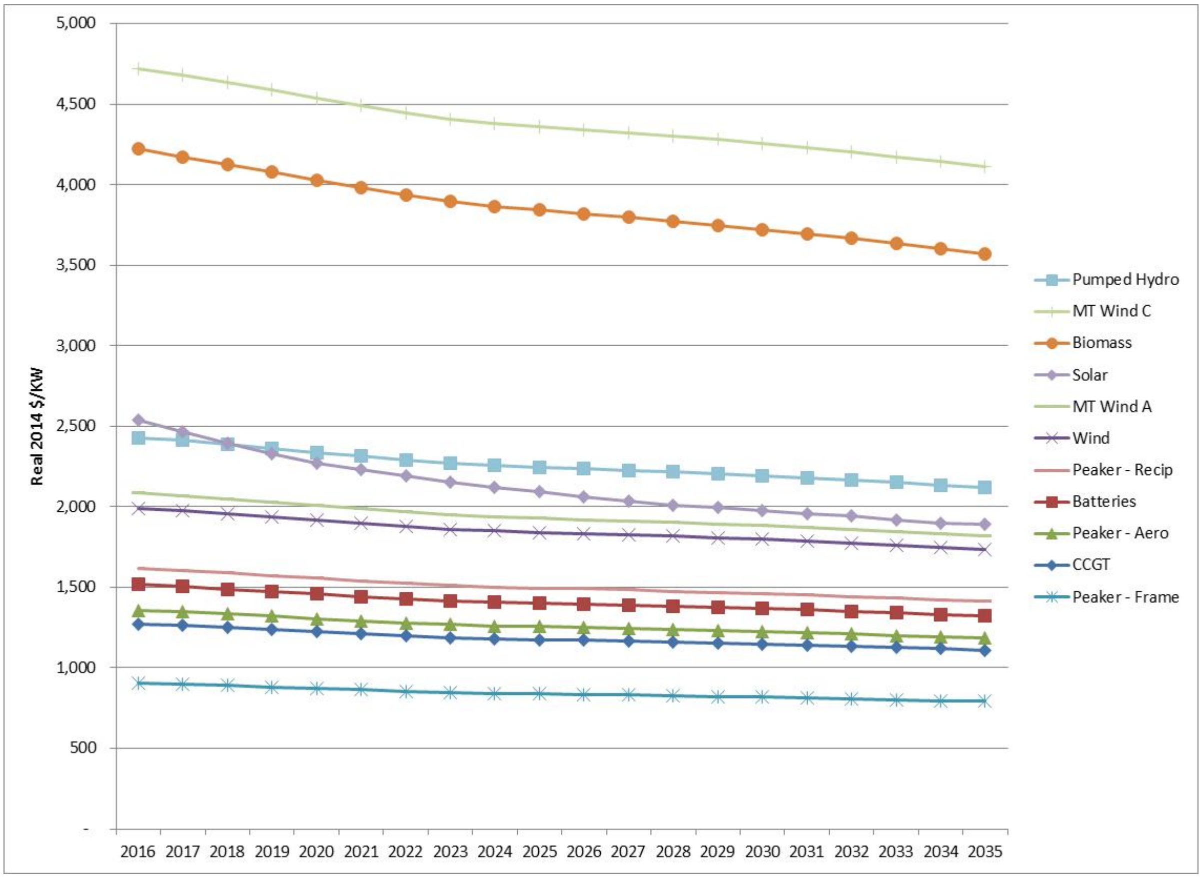
Figure 4-18 displays the monthly capacity factor for Washington wind, Montana wind, and Washington solar.

Figure 4-18: Capacity Factor for Wind and Solar



The change in capital cost by vintage year (year the plant is built) is based on the EIA AEO 2014 Overnight Cost curves. These costs are decreasing on a real basis, but we then add a 2.5 percent annual inflation rate for nominal costs. Figure 4-19 shows the annual capital cost of a resource by year built in 2014 real dollars.

Figure 4-19: Annual Capital Costs by Vintage Year (real 2014 dollars)



Heat Rates. PSE applies the improvements in new plant heat rates as estimated by the EIA in the AEO Base Case Scenario. New equipment heat rates are expected to improve slightly over time, as they have in the past. PSE also applies a 2 percent increase to the heat rates to account for the average degradation over the life of the plant.

Federal Subsidies. Three federal subsidies reduced renewable resource costs in the U.S. during the most recent expansion of the renewable resource industry; however, these subsidies have now expired, and there is no momentum for renewal at this time. Since PSE has no near-term need for more renewable resources, this IRP does not include any additional resources to which such subsidies would apply if available.

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

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state’s RPS e.g. 3 percent in 2015, then 15 percent in 2020 for Washington State. Then we apply these requirements to each state’s load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing and "proposed" renewable energy resources are accounted for, "new" renewable energy resources are matched to the load to meet the applicable RPS. Following an internal and external review for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass and geothermal. PSE used the same methodology as the NPCC to identify potential production by states. Production varies considerably depending on local conditions, e.g. Arizona has little wind potential but great solar potential. Appendix C, Environmental Matters, includes a table that identifies renewable portfolio standards for the states in the WECC.

Build and Retirement Constraints. Absent constraints, the AURORA model would identify coal as a least-cost resource and build new coal units in the WECC. To reflect current political and regulatory trends, PSE added constraints on coal technologies to the AURORA model. Specifically:

- No new coal builds are allowed in Washington. State law RCW 80.80 (Greenhouse Gases Emissions-Baseload Electric Generation Performance Standard) prohibits construction of new coal-fired generation within this state without carbon capture and sequestration.
- No new coal builds are allowed in any state in the WECC. In addition, all WECC coal plants must meet the National Ambient Air Quality Standards (NAAQS) and the Mercury and Air Toxics Standards (MATS).
- Any plant that has announced retirement is reflected in the database.
- California power plants that would be shuttered by that state's Once-through Cooling regulations are retired.

Further discussion of planned builds and retirements in WECC are discussed in Appendix N, Electric Analysis.

Electric Portfolio Sensitivity Reasoning

Baseline assumptions are included in all portfolios. Sensitivities change one of those assumptions in order to isolate the effect of an individual variable on resource portfolios.

Colstrip. Several proposed or recently enacted rules will affect the operation of the Colstrip plant in eastern Montana in coming years, so this IRP tests reducing reliance on Colstrip and eliminating it entirely.

BASELINE ASSUMPTION: All 4 units remain in service for the full planning period.
Sensitivity 1 > Retire Units 1 & 2 in 2026.
Sensitivity 2 > Retire all 4 units in 2026.

Demand-side Resources (DSR). This sensitivity looks at the effect of no additional DSR on portfolio cost and risk; all future needs are met with supply-side resources.

BASELINE ASSUMPTION: All cost-effective DSR per RPS requirements.
Sensitivity 1 > Existing DSR measures stay in place, but all future needs are met with supply-side resources.

Thermal Mix. This sensitivity models different configurations of thermal resources.

BASELINE ASSUMPTION: Frame peakers were selected as the lowest-cost thermal resource addition in the deterministic analysis for the Base Scenario.
Sensitivity 1 > This sensitivity models all CCCT plants instead of peakers.
Sensitivity 2 > This sensitivity models a mix of frame peakers and CCCT plants.

Gas Plant Location. The purpose of this sensitivity is to model the cost differences between building a gas plant in PSE's service territory on the western side of the Cascades versus building a plant in eastern Washington. The CCCT and peakers without oil backup located in western Washington have 100 percent firm pipeline transportation on NOVA, Foothills and GTN to AECO, with 20% storage. The western Washington located peakers with oil backup have 50 percent firm pipeline transportation on NOVA, Foothills and GTN to AECO, with 20% storage. All plants located in eastern Washington include firm Bonneville Power Administration transmission contract costs. A full discussion of costs and assumptions is located in Appendix D, Electric Resources and Alternatives.

BASELINE ASSUMPTION: Gas plants are located in PSE's service territory with no added transmission cost and fuel transport to Sumas.
Sensitivity 1 > Gas plants located in eastern Washington with firm transmission on BPA and fuel transport to AECO.

Gas Transport/Oil Backup for Peakers. The baseline assumption for peakers is that they have 50 percent of firm pipeline capacity and two days (48 hours) of oil backup, so they can rely on less expensive non-firm pipeline capacity for the remaining 50 percent of gas transport needs. The assumption is that 48 hours is enough time to find the needed pipeline capacity on the wholesale market. Available pipeline capacity is decreasing however, so the risk of being unable to acquire capacity when needed is increasing. This sensitivity tests the costs and risks associated with relying on more-expensive firm pipeline capacity for 100 percent of gas needs compared to 50 percent firm/50 percent non-firm capacity with 48 hours of oil backup.

BASELINE ASSUMPTION: Non-firm pipeline capacity with oil backup.
Sensitivity 1 > Firm pipeline capacity with no oil backup.

Energy Storage/Flexibility. This sensitivity tests the effect of added batteries or pumped storage on the portfolio. Given the nature of storage resources, it is hard to compare them directly to a supply- or demand-side resource, so this test forces batteries and pumped storage into the portfolio so we can learn more about their impact on portfolio cost.

BASELINE ASSUMPTION: No contribution from pumped storage and batteries allowed to be added economically.
Sensitivity 1 > 80 MW battery added into the portfolio in 2023 instead of economically chosen peaker.
Sensitivity 2 > 80 MW pumped hydro storage added into the portfolio in 2023 instead of economically chosen peaker.
Sensitivity 3 > 200 MW pumped hydro storage added into the portfolio in 2023 instead of economically chosen peaker.

Reciprocating Engines/Flexibility. This sensitivity looks at a lower-cost and smaller-sized configuration of reciprocating engine peakers. It also considers the flexibility benefit of reciprocating peakers on the portfolio.

> **BASELINE ASSUMPTION:** Reciprocating peakers modeled at 220 MW with an all-in cost of $1,599 per kW.
> **Sensitivity 1** > Recip peakers modeled at 75 MW with a lower updated all-in cost of $1,404 per kW
> **Sensitivity 2** > Add 75 MW recip peakers to the portfolio in 2023 with the updated all-in cost of $1,404 per kW.
> **Sensitivity 3** > Add 75 MW recip peaker in 2023 with the flexibility benefit from the 2013 IRP of $18.23 per kW-yr.[6] This benefit was subtracted from the fixed operating and maintenance costs.

Montana Wind. The purpose of this sensitivity is to model a lower cost assumption for transmission from Montana. The current assumption models the Montana wind transmission and substation costs at $662 million. This includes line upgrades for the Judith Gap to Broadview line, an expanded Broadview substation, new Broadview to Garrison Line and an expanded Garrison substation. The assumption also includes a 6.7 percent line loss from Judith Gap to Garrison. A full discussion of the Montana wind assumptions can be found in Appendix D, Electric Resources and Alternatives.

> **BASELINE ASSUMPTION:** Use PSE cost estimate for transmission upgrades to Montana.
> **Sensitivity 1 >** Include lower transmission cost estimate of $117 million for upgrades to Montana at the request of IRPAG stakeholder.

6 / See Appendix H, Operational Flexibility, for further information.

Solar Penetration. In past IRPs, rooftop solar PV installed by PSE customers (also known as distributed solar) was included as part of the demand-side resource bundles analyzed for the portfolio. Solar PV is cost effective from the customer's point of view because of the subsidies customers receive for installing rooftop solar panels; however, those subsidies are not experienced by PSE. Under the Total Resource Cost (TRC) approach that PSE uses to determine DSR cost effectiveness, distributed solar PV is not cost effective and therefore not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately. As part of our ongoing study of emerging resources, this IRP treats distributed solar separately as a must-take demand-side resource. Working with Cadmus, we developed a 20-year forecast of expected growth based on the current 15 MW capacity that our net metering customers represent plus estimated rates of adoption. This forecast is applied as a no-cost reduction in customer demand. The sensitivity tests the impact of achieving maximum capture of potential rooftop solar.

BASELINE ASSUMPTION: 20-year forecast of expected growth in rooftop solar PV
Sensitivity 1 > Maximum capture of potential rooftop solar. An explanation of how the potential was developed can be found in Appendix M, Distributed Solar.

Figure 4-19: Market Potential in 2035

	aMW	MW
Baseline Additions	0.18	3
Max Potential Additions	36.7	309

Carbon Reduction. This sensitivity looks at the cost of adding carbon reduction measures beyond RPS requirements by adding additional wind, solar or DSR to the portfolio.

BASELINE ASSUMPTION: Renewable resources and DSR per RPS requirements.
Sensitivity 1 > Increase renewable resources beyond RPS requirements by adding 300 MW of Washington wind in 2021.
Sensitivity 2 > Increase renewable resources beyond RPS requirements by adding 300 MW of utility-scale solar in 2021.
Sensitivity 3 > Increase DSR beyond RPS requirements by adding more DSR beyond the cost-effective bundle D.

Gas Sales Assumptions

Resource Assumptions. Transportation and storage are key resources for natural gas utilities. Transporting gas from production areas or market hubs to PSE's service area generally requires assembling a number of specific pipeline segments and/or gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. See Chapter 7, Gas Sales Analysis, for further information.

In this IRP, eight alternatives were tested in the analyses.

1. Northern British Columbia (BC) gas at the Station 2 hub, delivered via Westcoast and Northwest Pipeline (NWP) expansions to PSE's service area.
2. AECO gas delivered to PSE via existing or expanded capacity on NOVA and Foothills pipelines, the prospective FORTIS BC Kingsvale-Oliver Reinforcement Project (KORP) and then on expanded NWP.
3. Delivery of AECO gas via NOVA, Foothills and GTN pipelines, with final delivery via a prospective Cross Cascades pipeline with an expansion on NWP (N-MAX, Palomar/Blue Bridge).
4. Purchase gas directly at Malin (or transported from the Rockies hub on the Ruby Pipeline), transport by back-haul on the GTN pipeline and on a prospective Cross Cascades pipeline and then on an NWP expansion to PSE's service area.
5. Develop an on-system LNG peaking resource to serve the needs of core gas customers that can also serve additional markets, including transportation.
6. Acquire MIST Storage from Northwest Natural after an expansion of the Mist storage facility.
7. Upgrade the existing Swarr LP-air facility.
8. Demand-side resources include energy efficiency measures and building codes and standards.

Build Constraints. Gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent "lumpiness" in gas pipeline expansion, since expanding pipelines in small increments every year is not practical. Pipeline companies need minimum capacity commitments to make an expansion economically viable. Thus the model is constrained to evaluate pipeline expansions in four-year blocks: 2018, 2022, 2026 and 2030. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility's upgrade was made available in two-year blocks: the winter of 2016/2017 and again in 2018/2019.

Gas Sales Sensitivities

Alternate Discount Rate Sensitivity. When gas prices fell to historic lows in recent years, the costs that utilities incurred to achieve DSR conservation goals became much harder to justify. For example, $30 of investment in energy efficiency measures may produce only $20 of immediate benefit today. However, conservation measures continue to accrue value over time, so $20 of benefit today may be worth $50 ten years from now. To model the value of DSR over time, this sensitivity tests the impact of using an "alternate discount rate" to evaluate cost-effective conservation. The baseline assumption is to use the weighted average cost of capital (WACC) assigned to PSE via rate cases to evaluate DSR measures.

> **BASELINE ASSUMPTION:** Use PSE current allowed WACC as the discount rate.
> **Sensitivity 1 >** Use alternate discount rate of 4.93% instead of the WACC discount rate.

Pipeline Timing Sensitivity. In its response to the 2013 IRP, the Washington Utilities and Transportation Commission made the following request: "In the next IRP, PSE should conduct a second run of its model once the appropriate blocks of pipeline capacity are selected, to assess whether early acquisition of pipeline blocks impacts the timing of the selection of other resources." [7] This sensitivity examines that possibility.

> **BASELINE ASSUMPTION:** Pipeline capacity expansions are built in 2022, 2026 and 2030.
> **Sensitivity 1 >** Pipeline capacity expansion is allowed every year starting in 2022.

7 | Attachment A, Washington Utilities and Transportation Commission Comments on Puget Sound Energy's 2013 Integrated Resource Plan Dockets UE-120767 & UG-120768 Section IV, Natural Gas Resources, Page 10.

DEMAND FORECASTS

Contents

The system-level demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts, and peak demand over a 20-year period. These estimates are designed for use in long-term resource planning. The 20-year horizon helps us anticipate needs so we can plan to efficiently meet the needs of our customers.

OVERVIEW

At the system level, growth rates have slowed since the 2013 IRP forecast. Recovery from the latest recession has been slower than expected, and as a result, both the nation and the region are experiencing slower population growth, slower GDP growth and slower employment growth than forecast in the 2013 IRP. Within PSE's service territory, however, demand growth is uneven. Most of the economic growth is concentrated in King County. Other counties are growing, but slowly; except for King County, none has reached its pre-recession growth levels in terms of population or employment.

The 2015 IRP Electric Base Demand Forecast for energy and peak loads is lower than those forecast in the 2013 IRP.

The 2015 IRP Gas Base Demand Forecast for energy and peak loads is slightly higher early in the forecast period compared to the 2013 IRP, but has similar levels for the second half of the forecast horizon. The near-term higher loads are due to lower natural gas prices causing increased gas consumption by customers.

King County, which accounts for half or more of the system's electric and gas sales demand today, is growing rapidly, particularly in an area referred to as the "Eastside Area." This geographic region is located east of Lake Washington and includes Bellevue (including Bellevue's central business district), Mercer Island, Newcastle and portions of Kirkland, Redmond, Renton and Issaquah. Employment in the Eastside Area is expected to grow about 1.8 percent annually in the next 20 years, according to a forecast prepared by the Puget Sound Regional Council (PSRC). This is over twice the growth rate expected for the system as a whole in an area that already accounts for the largest portion of system load.

Figures 5-1 to 5-4 show the wide variation in county shares of PSE's total population, employment, customers and sales for the electric and gas service territories.

For this IRP, PSE developed both system-level forecasts and county-level forecasts. The system level forecasts are designed for use in long-term resource planning and long-term financial planning. The county-level forecasts provide insight into which parts of the system will be most challenged, and these forecasts are used internally at PSE for local transmission and distribution system planning. The system-level and county-level forecast methodologies and assumptions are explained in the following pages.

Treatment of Demand-side Resources in IRP Demand Forecasts.

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. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of conservation savings. Therefore, the IRP Electric and Gas Demand Forecasts include only DSR measures implemented ***before*** the study period begins in 2016. These charts and tables are labeled “before DSR.”

In the IRP analysis, DSR is ultimately accounted for as a reduction in demand. To illustrate this effect, this chapter includes several examples that apply the full amount of DSR identified as cost-effective in the 2013 IRP to the 2015 IRP Demand Forecasts. These charts and tables are labeled “after applying 2013 IRP DSR.”

Figure 5-1: PSE Electric Service Territory

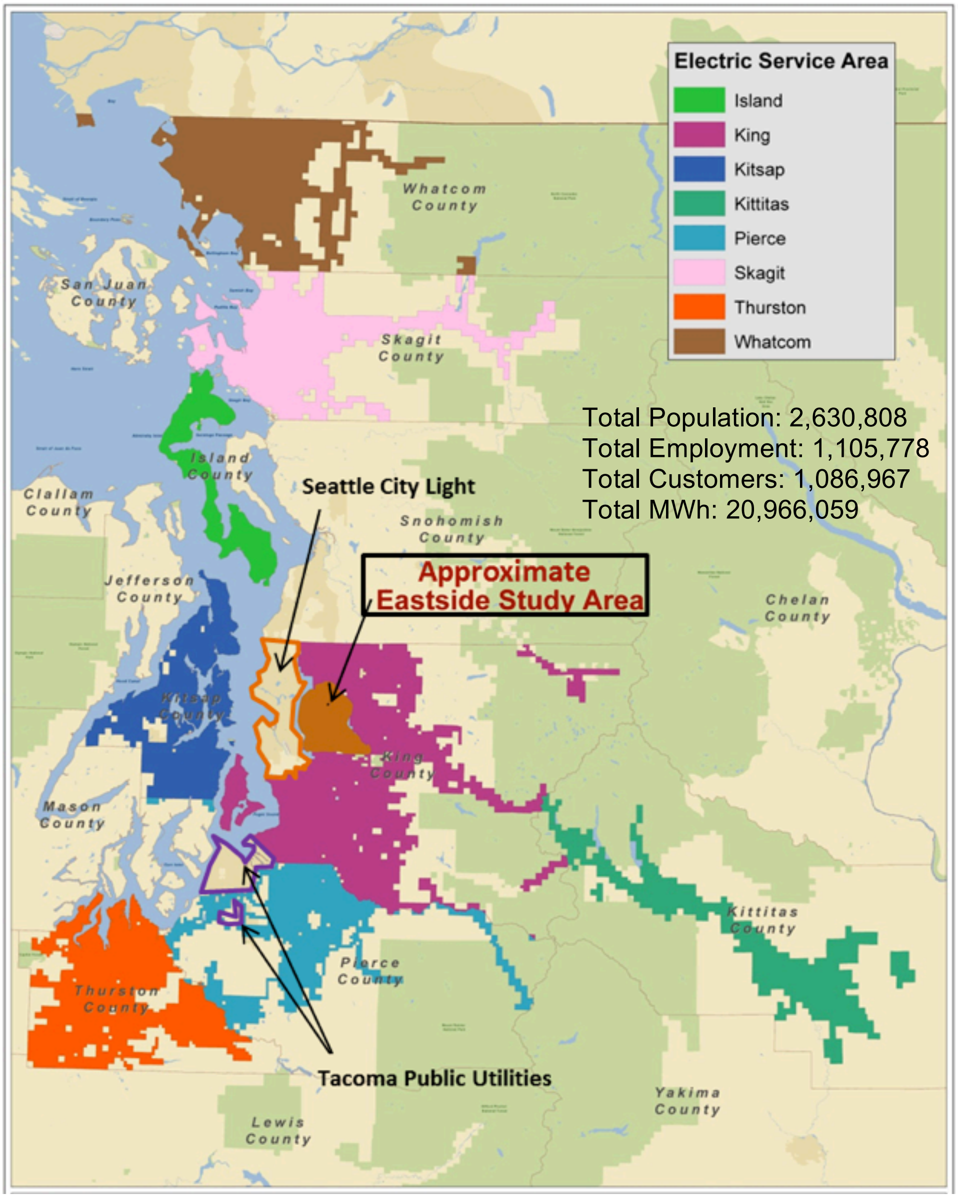


Figure 5-2: Electric Service Area, Counties and Eastside Area, Percent of PSE Total, 2013 data

County	Population	Employment	Customers	Sales
King	48%	58%	49%	52%
Thurston	10%	9%	11%	11%
Pierce	15%	10%	10%	9%
Kitsap	10%	8%	11%	9%
Whatcom	8%	8%	9%	9%
Skagit	5%	4%	5%	7%
Island	3%	1%	3%	2%
Kittitas	2%	1%	1%	1%
Eastside Area	9%	19%	10%	14%

Figure 5-3: PSE Gas Service Territory

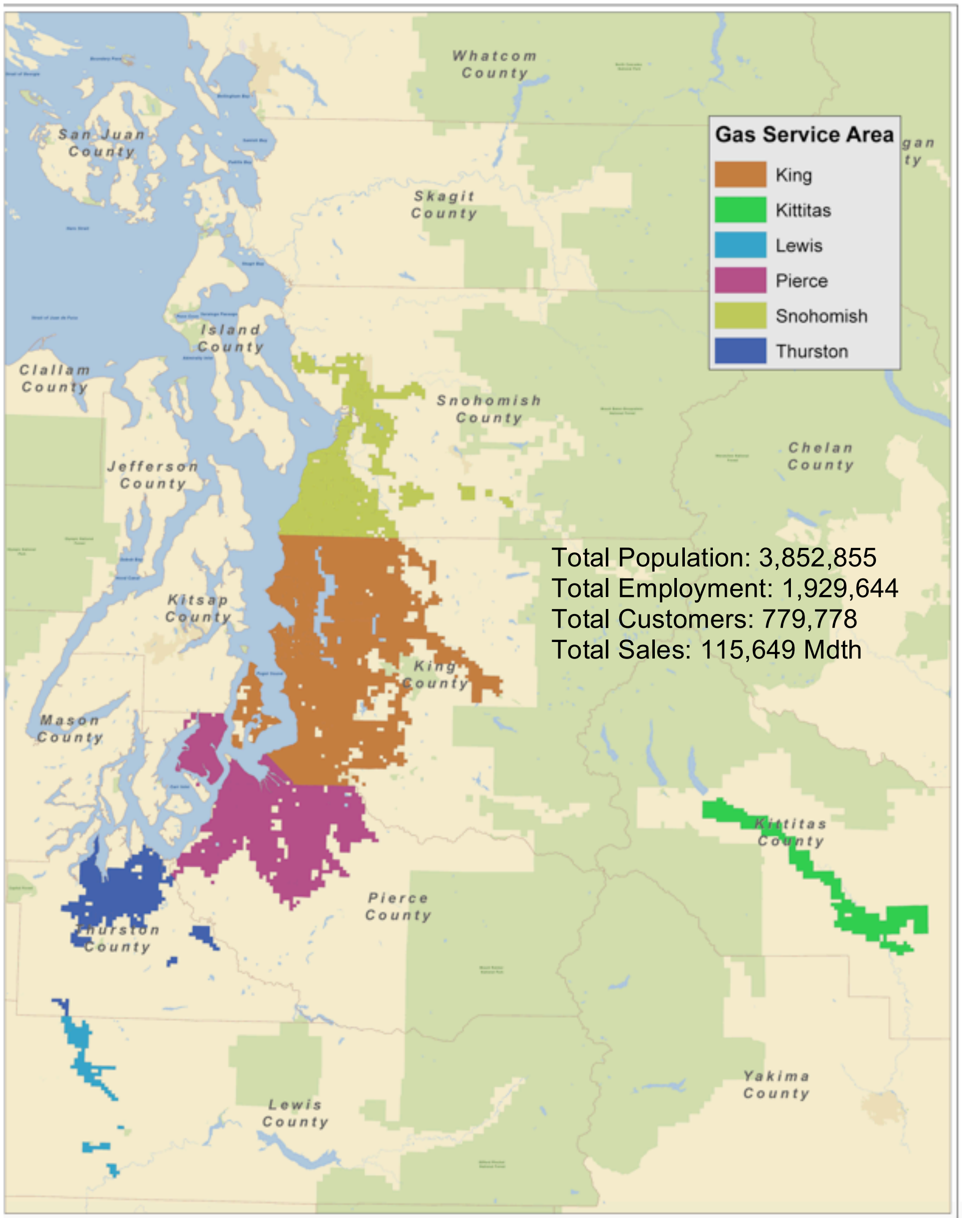
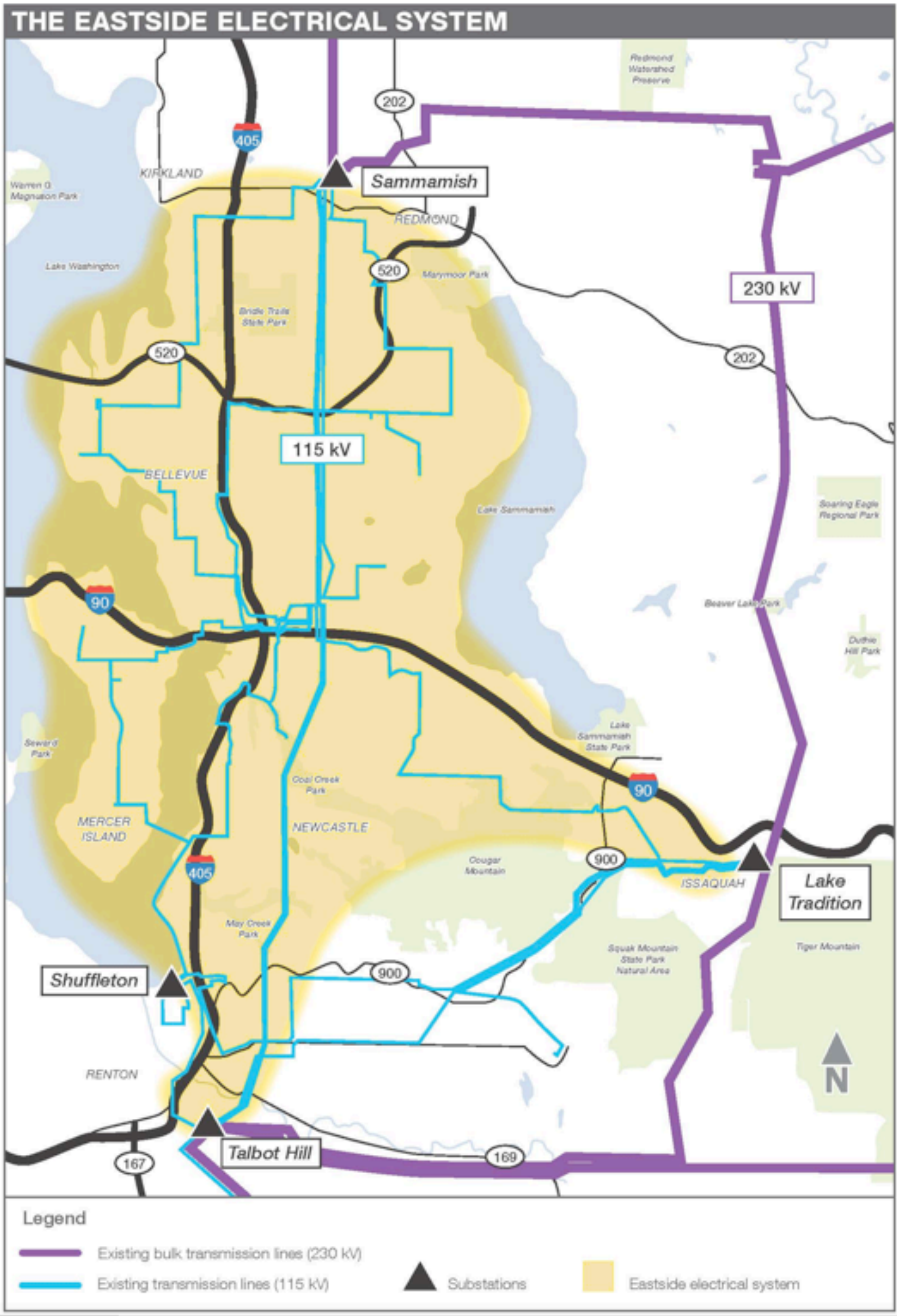


Figure 5-4: Gas Service Territory: County Share as a Percent of PSE total, 2013 data

County	Population	Employment	Customers	Sales
King	52%	65%	57%	57%
Pierce	21%	15%	19%	22%
Snohomish	19%	14%	17%	15%
Thurston	7%	5%	6%	5%
Lewis	1%	1%	1%	1%
Kittitas	1%	1%	<1%	<1%

Figure 5-5: Eastside Area Electric System



METHODOLOGIES

The methodology used to develop the system-level forecast is described first, followed by the methodology used for county-level forecasts. Finally, the methodology for developing the Eastside Area forecast is described.

System-level Methodology

PSE's regional economic and demographic model uses both national and regional data to produce a forecast of total employment, types of employment, unemployment, personal income, population, households, consumer price index (CPI) and building permits for both the PSE electric and gas service territories. The regional economic and demographic data are built up from county-level or MSA (metropolitan statistical area)-level information from various sources. The load-forecasting process is illustrated in Figure 5-6, and the input data sources are listed in Figure 5-7.

Figure 5-6: PSE Load Forecasting Process

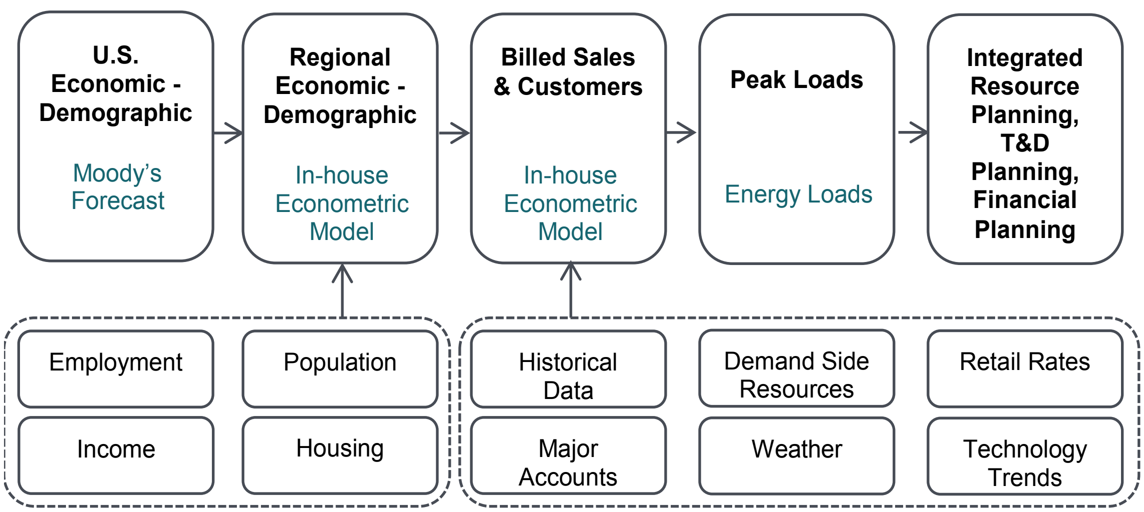


Figure 5-7: Sources for U.S. and Regional Economic and Demographic Data

DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL	
County-level Data	**Source**
Labor force, employment, unemployment rate	US Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department, using data from Quarterly Census of Employment and Wages fortress.wa.gov/home
Personal income	US Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	
Population	
Households, single- and multi-family	US Census censtats.census.gov
Household size, single- and multi-family	
Housing permits, single- and multi-family	Building Industry Association of Washington (BIAW) www.biaw.com
Aerospace Employment	Puget Sound Economic Forecaster www.economicforecaster.com
US-level Data	**Source**
GDP	Moody's Analytics www.economy.com
Industrial Production Index	
Employment	
Unemployment rate	
Personal income	
Wages and salary disbursements	
Consumer Price Index (CPI)	
Housing starts	
Population	
Conventional mortgage rate	
T-bill rate, 3 months	

A wide variety of electricity and natural gas uses are assumed as inputs.

- For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions, computers and various other plug loads.
- Commercial and industrial customers use energy for production processes; space heating, ventilation and air conditioning (HVAC); lighting; computers; and other office equipment.

To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale and transport or customers under schedule 449 purchasing their power from other suppliers.
- Gas customer classes include firm (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible (commercial and industrial), and transport (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Transport Customers

"Transport" in the natural gas industry has historically referred to customers that acquire their own natural gas from third-party suppliers and rely on the gas utility for distribution service. It does not refer to natural gas fuel for vehicles.

Regression equations are used to forecast the number of customers by class as well as the use per customer (UPC) by class. These are multiplied together to arrive at the billed sales forecast. The main drivers of these equations include population or households, housing permits, unemployment rates, retail rates, personal income, weather, total employment and manufacturing employment. Weather inputs are based on temperature readings from Sea-Tac Airport.

For detailed technical descriptions of the econometric methodologies used to forecast billed energy sales and customer counts, peak loads for electricity and natural gas, hourly distribution of electric loads and forecast uncertainty, see Appendix E, Demand Forecasting Models.

System-level High and Low Scenarios. Once the base demand forecast scenario is set, PSE develops high and low growth scenarios by performing 250 stochastic simulations for PSE's economic and demographic model. These simulations use the standard errors for key regional variables such as population, employment and income. The economic assumptions for the low and high scenarios represent the 5th and 95th percentile of the simulations, respectively. More detailed discussion of the stochastic simulations is presented in Appendix E, Demand Forecasting Models.

County-level Methodology

The same regional economic and demographic inputs are used for the electric county-level load forecast models as the system-level model; these are disaggregated into the different counties to ensure consistency with the system-level inputs.

As in the system-level approach, the customer count forecast for each class within each county is modeled as an econometric equation. However, the use per customer equation for each class is scaled to the county level using actual weather-normalized use per customer by county.

Electric peak loads by county were forecast using an approach similar to the system-level approach, given system coincident actual peaks at the county level using substation data. The individual county forecasts were then subject to adding up restrictions so the sum of the county forecasts equals the system-level forecast.

PSE did not produce a peak gas forecast at the county level because of the dearth of actual gas peak day data by county.

Eastside Area Methodology

Because data required for PSE's economic and demographic models is not available on a sub-county level, different data sources were used for the Eastside Area. This information was broken out by census tract and/or collected directly from PSE's billing system and substations that serve the area. Sources included the following:

- Historical data and employment forecasts from the PSRC, by census tract,
- Historical population data from the Washington State Office of Financial Management (WA OFM) and population growth forecasts from PSRC, also by census tract,
- Actual customer counts and billed sales by customer class collected from PSE's billing system, and
- System coincident peaks collected from the substations serving this area.

KEY ASSUMPTIONS

To develop PSE's demand forecasts, assumptions must be made about economic growth, energy prices, weather and loss factors, including certain system-specific conditions. These and other assumptions are described below.

Economic Growth

Economic activity has a significant effect on energy demand. Overall, recovery from the effects of the latest recession has been slower than expected. As a result, both the nation and the region are experiencing slower population growth, slower GDP growth and slower employment growth than forecast when the 2013 IRP was prepared. In PSE's service territory, economic growth is uneven. King County, and in particular the Eastside Area, is growing much faster than the rest of the electric service territory. Both building permits and employment growth in that area far exceed other parts of the service territory.

National Economic Outlook. Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, PSE's system-level forecast begins with assumptions about what is happening in the broader U.S. economy. We rely on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy, for both economic and population growth rates. The June 2014 forecast was used for this IRP.

Moody's forecast calls for:

- U.S. GDP growth to reach nearly 4 percent in 2015, a year slower than the Moody's forecast used in the 2013 IRP.
- Average population growth of 0.78 percent per year for 2014-2033, down from 0.92 percent forecast in the 2013 IRP (2014-2033).

Slower population growth is attributed to lower birth rates and lower international migration.

Economic growth could slow further if the Federal Reserve becomes aggressive in its interest rate setting; if Europe's economic problems continue to persist, especially combined with the Russia-Ukraine conflict; and if China's economy experiences a slowdown amid increasing tensions with its neighbors. However, many believe that the U.S. economy will be able to withstand these threats and continue to recover from the recent recession.

Regional Economic Outlook. PSE prepares regional economic and demographic forecasts using econometric models whose primary input is a macroeconomic forecast of the United States plus historical economic data for the counties in PSE's service area.

Electric Base Demand Scenario Outlook. The following assumptions are modeled in the 2015 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate (aarg) of 0.7 percent between 2016 and 2035, compared to the forecasted annual growth rate in the 2013 IRP of 1.4 percent.
- Manufacturing employment is expected to decline annually by 0.4 percent on average between 2016 and 2035, continuing a long trend, due to capital investments that create increases in productivity.
- Local employers are expected to create about 297,000 jobs between 2016 and 2035 as compared to more than 596,000 jobs in the 2013 IRP (2012 to 2033).
- An inflow of more than 775,000 new residents between 2016 and 2035 will increase PSE's electric service territory population to almost 4.8 million by 2035. This is lower than the 2013 IRP forecast of a little over 1 million new residents between 2012 and 2033.

As explained above, the slightly slower long-term growth in employment is attributed to the slower than expected recovery from the effects of the latest recession and lower population growth expected by the U.S. Census Bureau.

In the region, long-term growth is driven by a diverse group of employers that includes Microsoft, Amazon, Costco, REI, Boeing and Starbucks among others. Boeing's strong historical employment growth is not necessarily expected to continue, due to outsourcing and an increase in the number of planes assembled in other states.

Electric High and Low Scenario Outlooks. For the Low Electric Demand Forecast scenario, population grows by 0.8 percent annually from 2016 to 2035. Employment grows 0.1 percent annually from 2016 to 2035.

For the High Electric Demand Forecast scenario, population grows by 1.1 percent annually from 2016 to 2035, and employment grows by 1.3 percent per year during that period.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 5-8 and 5-9.

Figure 5-8: Population Growth, Electric Service Area

POPULATION GROWTH, ELECTRIC SERVICE AREA (1,000s)						
Scenario	2016	2020	2025	2030	2035	AARG 2016-2035
2015 IRP Base Demand Forecast	3,998	4,176	4,393	4,587	4,774	0.9%
2015 IRP High Demand Forecast	4,027	4,232	4,476	4,692	4,926	1.1%
2015 IRP Low Demand Forecast	3,970	4,119	4,308	4,477	4,645	0.8%

Figure 5-9: Employment Growth, Electric Service Area

EMPLOYMENT GROWTH, ELECTRIC SERVICE AREA (1,000s)						
Scenario	2016	2020	2025	2030	2035	AARG 2016-2035
2015 IRP Base Demand Forecast	2,021	2,093	2,163	2,233	2,318	0.7%
2015 IRP High Demand Forecast	2,111	2,260	2,403	2,529	2,703	1.3%
2015 IRP Low Demand Forecast	1,934	1,934	1,942	1,967	1,968	0.1%

Gas Scenario Outlooks: Base, High and Low. In the Base Gas Demand Forecast scenario, population grows by 1.2 percent annually from 4.1 million people in 2016 to almost 5.2 million people by 2035. Employment is expected to grow by 1.4 percent annually from 2016 to 2035.

For the Low Gas Demand Forecast scenario, population grows by 1.0 percent annually from 2016 to 2035. Employment grows 0.7 percent annually from 2016 to 2035.

For the High Gas Demand Forecast scenario, population grows by 1.3 percent annually from 2016 to 2035, and employment grows by 2.0 percent per year during that period.

The Base, High and Low population and employment forecasts for PSE's gas sales service area are compared in Figures 5-10 and 5-11.

Figure 5-10: Population Growth, Gas Service Area

POPULATION GROWTH, GAS SERVICE AREA (1,000s)						
Scenario	2016	2020	2025	2030	2035	AARG 2016-2035
2015 IRP Base Demand Forecast	4,146	4,364	4,640	4,900	5,161	1.2%
2015 IRP High Demand Forecast	4,173	4,428	4,734	5,026	5,346	1.3%
2015 IRP Low Demand Forecast	4,117	4,300	4,543	4,772	4,999	1.0%

Figure 5-11: Employment Growth, Gas Service Area

EMPLOYMENT GROWTH, GAS SERVICE AREA (1,000s)						
Scenario	2016	2020	2025	2030	2035	AARG 2016-2035
2015 IRP Base Demand Forecast	2,107	2,241	2,393	2,548	2,724	1.4%
2015 IRP High Demand Forecast	2,201	2,417	2,645	2,874	3,209	2.0%
2015 IRP Low Demand Forecast	2,011	2,067	2,150	2,249	2,306	0.7%

County-level Outlook

The charts below show the wide variation in economic activity among the counties in PSE's electric and gas sales service territories. Most of the economic growth is concentrated in King County, as can be seen by the growth in the number of building permits filed in the last five years and by the county's strong job growth. Other counties are growing, but more slowly; except for King County, none has reached its pre-recession growth levels. County-level forecasts extend only to 2031.

Eastside Area Outlook

In PSE's service territory, growth is strongest in the Eastside Area, especially in the central business district of Bellevue. Using census tract data, PSRC created 10-, 20-, and 30-year forecasts of population and employment for the area. According to this forecast, employment in the Eastside Area is expected to grow by about 1.7 percent annually in the next 20 years, with slightly higher growth before 2020 due to the recovery from the recession. This is over twice the growth rate expected for the system as a whole. Population is forecast to grow by 0.9 percent annually in the next 20 years, again with a slightly faster growth before 2020 due to the recovery from the most recent recession.

Figure 5-12: Residential Building Permits by County, 2000-2014

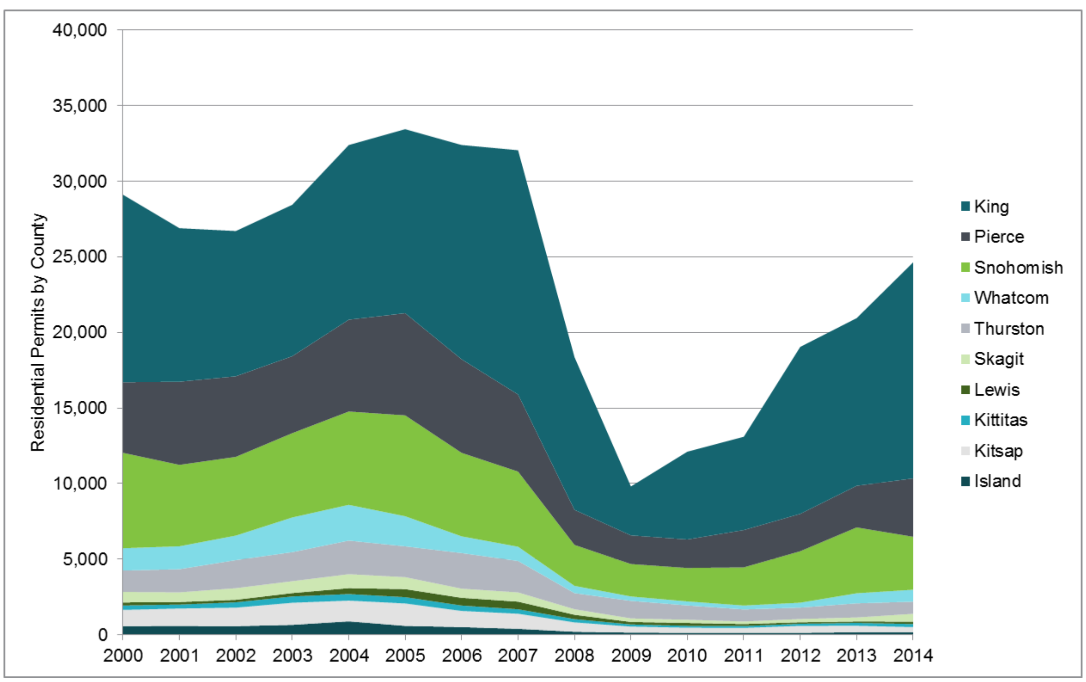


Figure 5-13: Population by County, Electric Service Territory Counties, 1990-2031

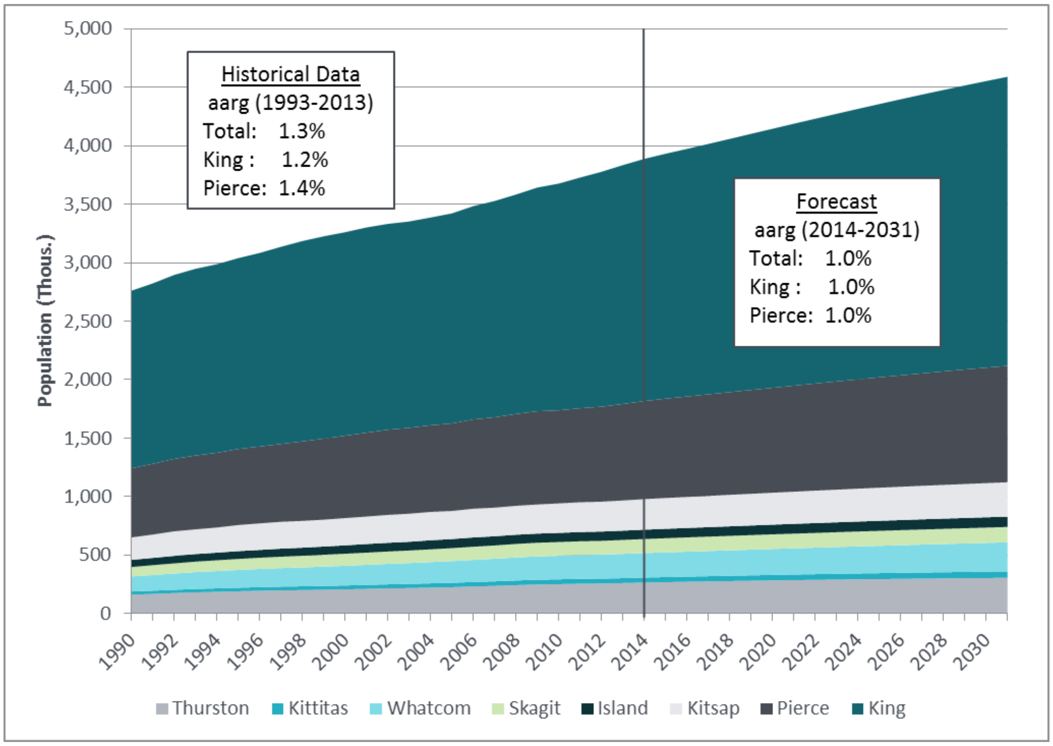


Figure 5-14: Employment by County, Electric Service Territory Counties, 1990-2031

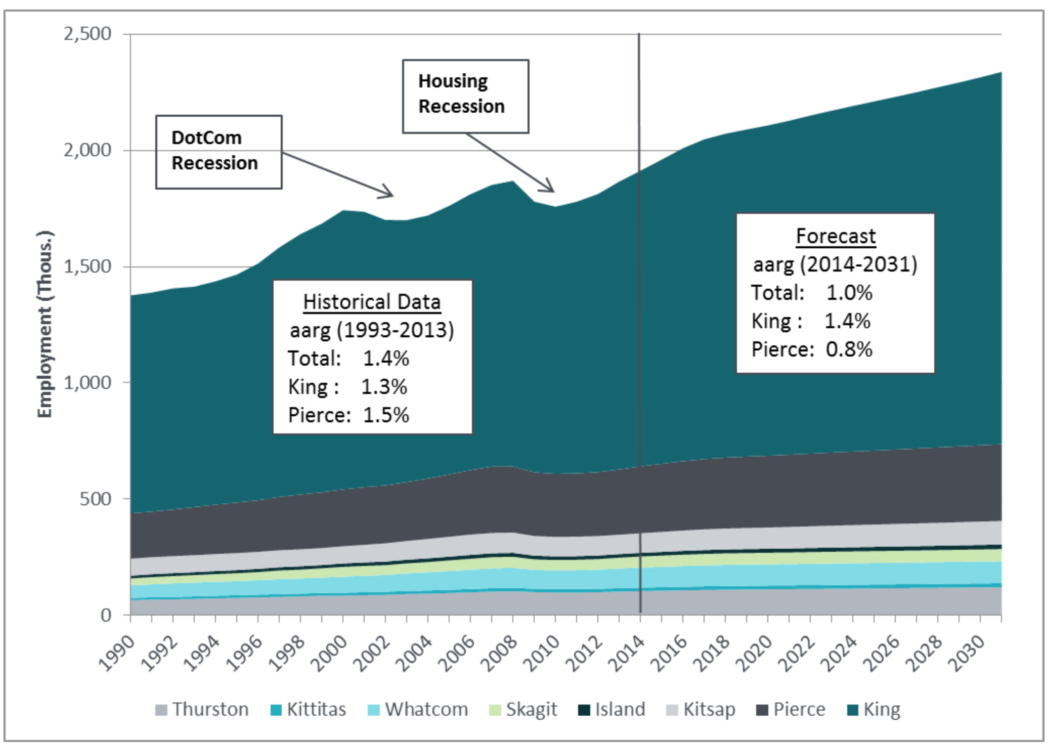


Figure 5-15: Population, Gas Service Territory Counties, 1990-2031

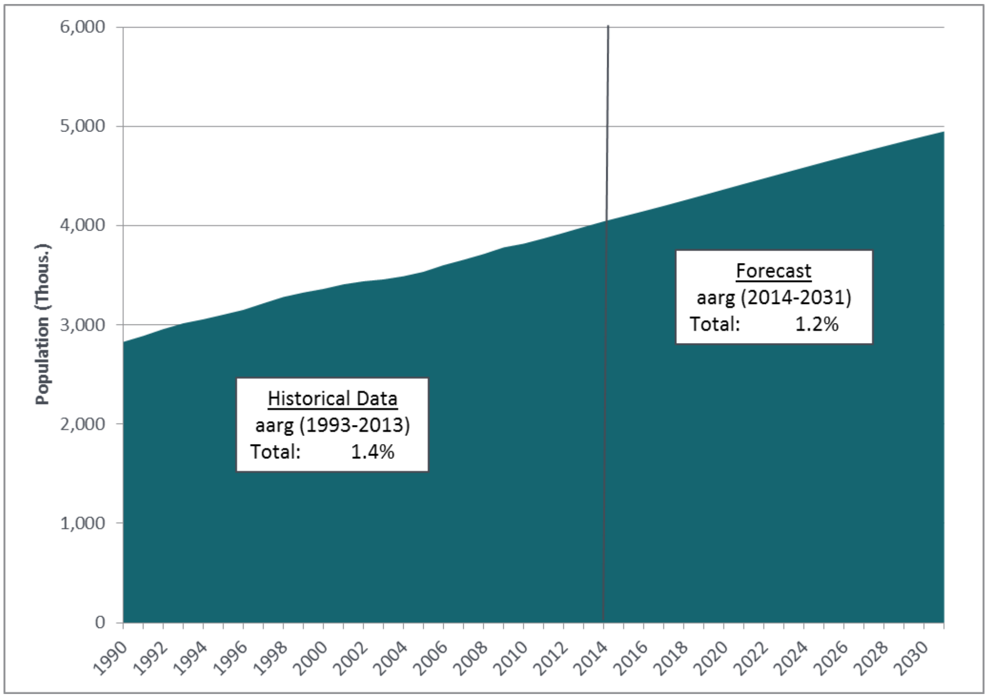
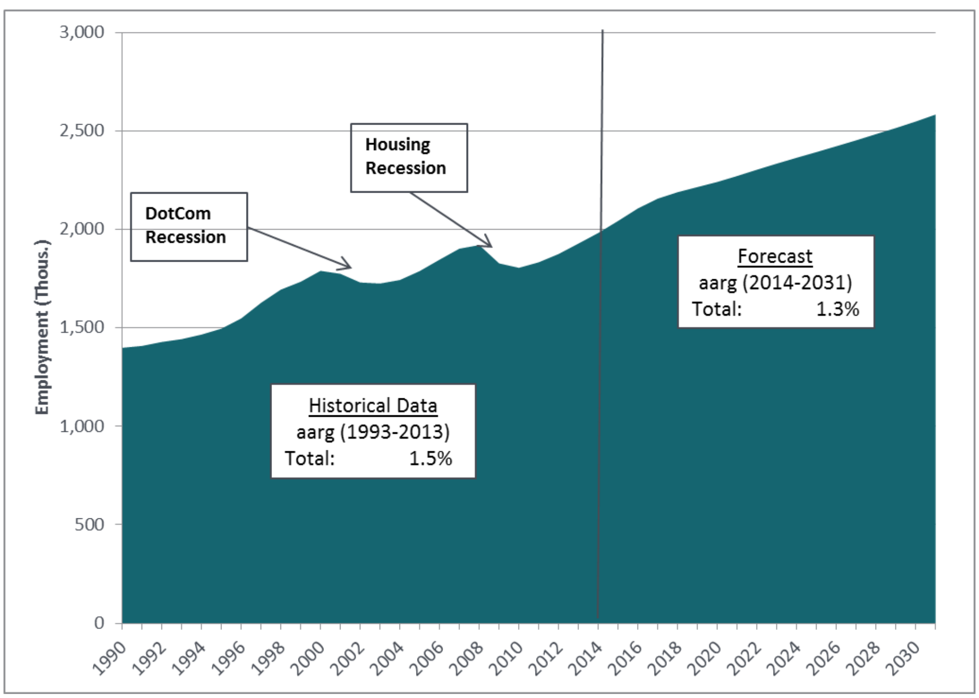


Figure 5-16: Employment, Gas Service Territory Counties, 1990-2031



Energy Prices

Retail energy prices – what customers pay for energy – are included as explanatory variables in the demand forecast models, because in the long run, they affect the customer's choice of the efficiency level of newly acquired appliances, their frequency and level of use and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

Electric Retail Prices. PSE projects that between 2016 and 2033, nominal retail electric rates will grow at an average annual rate of between 1.1 and 1.3 percent, depending on the customer class. Assuming an inflation rate of 2.5 percent per year, this means real electric retail rates are expected to decline by 1.2 to 1.4 percent. This is much lower than the 3.1 percent rate increase modeled in the 2013 IRP.

In the near term, the retail price forecast assumes rate increases resulting from PSE's general and power-cost-only rate cases. Long-term retail rates were derived from PSE's internal financial model, which showed lower power cost levels compared to the 2013 IRP, hence the lower growth rate assumed here.

Gas Retail Prices. PSE expects nominal retail gas rates to rise between 2.9 percent and 3.4 percent per year, depending on the class, between 2016 and 2033. This is slightly more than the long-term inflation rate. However, gas price levels are lower in this forecast compared to the forecast in the 2013 IRP for all classes except the transport classes.

Two components make up gas retail rates: the cost of gas and the cost of distribution, known as the distribution margin. The near-term forecast of gas rates includes PSE's purchased gas adjustment and general rate case considerations. Forecast gas costs reflect Kiodex gas prices for the 2015 to 2019 period as of July 24, 2014 and inflation projections beyond. The distribution margin is based on PSE's projection for the near term and inflation projections for the longer term.

Other Assumptions

Weather. The billed sales forecast is based on normal weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2013. While the climate may change during the 20-year planning horizon, reliable forecasts for these changes are not yet available. Future IRPs will incorporate new climate information as it becomes available.

Loss Factors. The electric loss factor remains at 6.9 percent, and the gas loss factor remains at 0.8 percent.

Block Load Additions from Major Accounts. Beyond typical economic change, the demand forecast also takes into account known major load additions and deletions, using information from PSE's system planners. These adjustments add 128 MW to demand over the next 7 years for the system as a whole. The majority of these additions come from King County.

King County is expected to add:

- 77 MW of load additions between 2014 and 2017
- 45 MW between 2018 and 2020

The Eastside Area is expected to add:

- 42 MW of load additions from 2014 to 2017
- 39 MW from 2018 to 2020

Block load additions are ramped into the forecast and then ramped out of the forecast, as the native load growth accounts for these additions. This avoids double counting block load additions.

The electric forecast also includes the following load additions and deletions.

- Approximately 9 MWs for horticultural lighting, mostly located in Thurston, Whatcom and Skagit counties
- Jefferson County has been deleted; it left PSE's electric service territory in April 2013.

The gas forecast includes the following block load additions.

- 6.4 Mdth per day is added for 2 large transport customers.
- The City of Buckley joined PSE's gas service territory in July 2014. (The city added 1,189 residential customers and 187 commercial customers in 2012; residential customers are expected to grow at an annual rate of 1.5 percent, and commercial customers are expected to grow at an annual rate of 0.5 percent.)

Compressed Natural Gas Vehicles. Compressed natural gas (CNG) vehicles were added to the 2015 IRP Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2015, this adds 50.9 Mdth to the forecast. This load is expected to grow at an average annual rate of 5.9 percent, based on the Annual Energy Outlook 2014 published by the U.S. Department of Energy.

Distributed Generation/Electric Vehicles. Distributed generation, including customer-level generation via solar panels, was not included in the load forecast; this energy production is captured in the IRP scenario modeling process. Analysis of electric vehicle loads in the 2011 IRP indicated that their impact on demand was insignificant, so electric vehicles are also not included in this demand forecast.

Interruptible Loads. PSE has 165 electric interruptible customers; 5 of these are commercial and industrial customers and 160 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 7 MW of coincident peak load. Since this 7 MW is so small compared to PSE's peak load, it was included in the firm load forecast; however, it has been accounted for in PSE's resource adequacy model. For a number of gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was included when forecasting peak gas loads.

ELECTRIC DEMAND FORECAST

Highlights of the system-level base, high and low demand forecasts PSE developed for the electric service area are presented below. County-level winter peak forecasts follow, plus a forecast for the Eastside Area, the most rapidly growing part of the service territory.

Demand-side resources (DSR), primarily energy efficiency measures, are treated differently at the system-level than they are at the county and sub-county level. At the system level, only DSR measures implemented through December 2015 are included, since the system-level demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio. County forecasts do not perform the same function, so those forecasts apply the full amount of DSR projected in the 2013 IRP, plus an additional 5 percent from 2016 to 2035 to account for the 2013 general rate case Global Settlement. The 2013 Global Settlement that approved decoupling mechanisms requires PSE to acquire an additional 5 percent of energy efficiency over and above the biennial target set for the company to comply with RCW 19.285.

System-level Highlights

Electric Load Growth. In the 2015 IRP Base Demand Forecast, total load is expected to grow at a rate of 1.8 percent annually from 2016 to 2025 and 1.5 percent annually from 2025 to 2035, for an average annual growth rate of 1.7 percent over the 20-year study period. Total load is expected to grow from 2,629 aMW in 2016 to 3,598 aMW in 2035. The rate is faster in the early years due to the continued economic recovery.

Residential and commercial loads are driving this growth; they represent 47 percent and 41 percent of load in 2016, respectively. On the residential side, use per customer is relatively flat, so growth in this category is being driven by the increase in the number of customers. On the commercial side, both use per customer and rising customer counts are driving growth.

The 2015 IRP High Demand Forecast projects an average annual growth rate of 2.2 percent; the Low Demand Forecast projects 1.1 percent.

Figure 5-17: Electric Demand Forecast before DSR
Base, High and Low Scenarios (aMW)

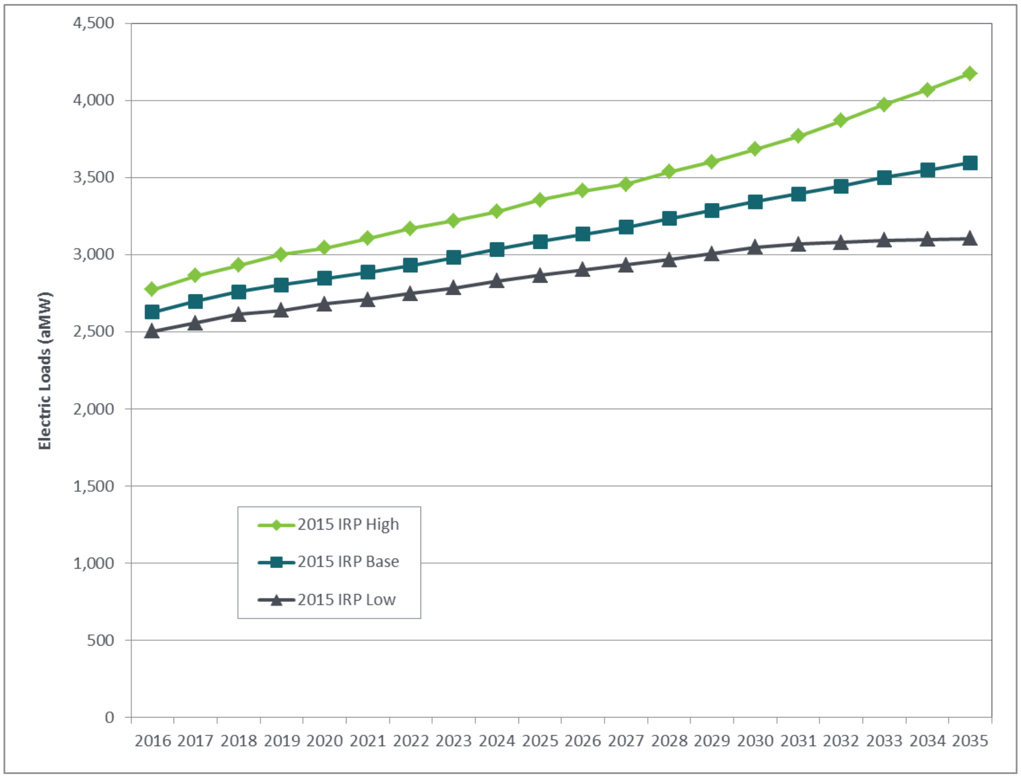


Figure 5-18: Electric Demand Forecast before DSR (Table)
Base, High and Low Scenarios

ELECTRIC DEMAND FORECAST SCENARIOS (aMW)						
Scenario	2016	2020	2025	2030	2035	AARG 2016-2035
2015 IRP Base Demand Forecast	2,629	2,850	3,088	3,345	3,598	1.7%
2015 IRP High Demand Forecast	2,776	3,044	3,357	3,685	4,176	2.2%
2015 IRP Low Demand Forecast	2,505	2,682	2,869	3,050	3,108	1.1%

Electric Peak Demand. The normal electric peak hour load is modeled using 23 degrees Fahrenheit. The 2015 IRP Base Demand Forecast shows an average annual peak load growth of 1.6 percent and an increase in peak load from 4,929 MW to 6,649 MW between 2016 and 2035. Demand grows faster in the first part of the forecast period due to the continued economic recovery (at 1.7 percent from 2016 to 2025 compared to 1.5 percent thereafter). The 2015 IRP Electric Base Demand Forecast is lower than the 2013 IRP Base Demand Forecast due primarily to the lower population forecast which led to a lower customer forecast.

The 2015 IRP High Demand Forecast shows an average annual peak load growth of 2.0 percent, and the Low Demand Forecast shows a 1.2 percent annual growth rate.

Figure 5-19: Electric Peak Demand Forecast before DSR
Base, High and Low Scenarios, Hourly Annual Peak (23 Degrees, MW)

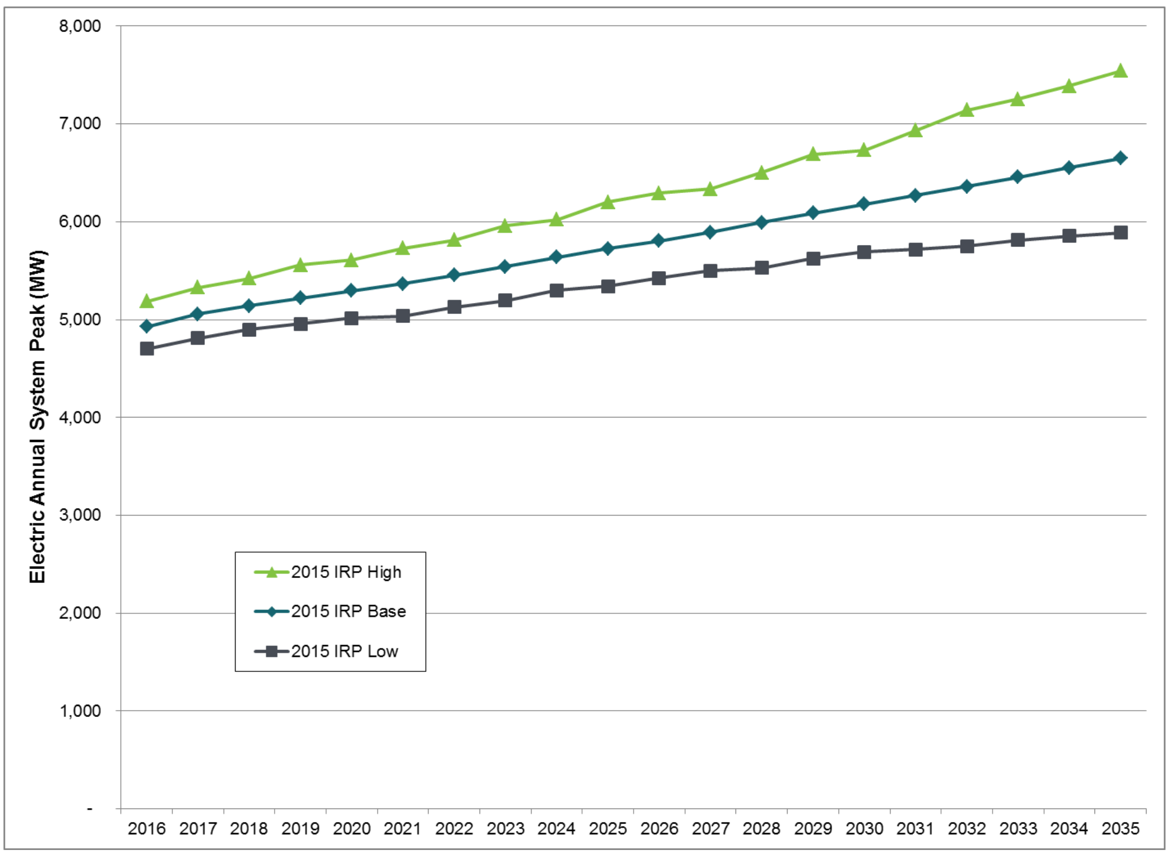
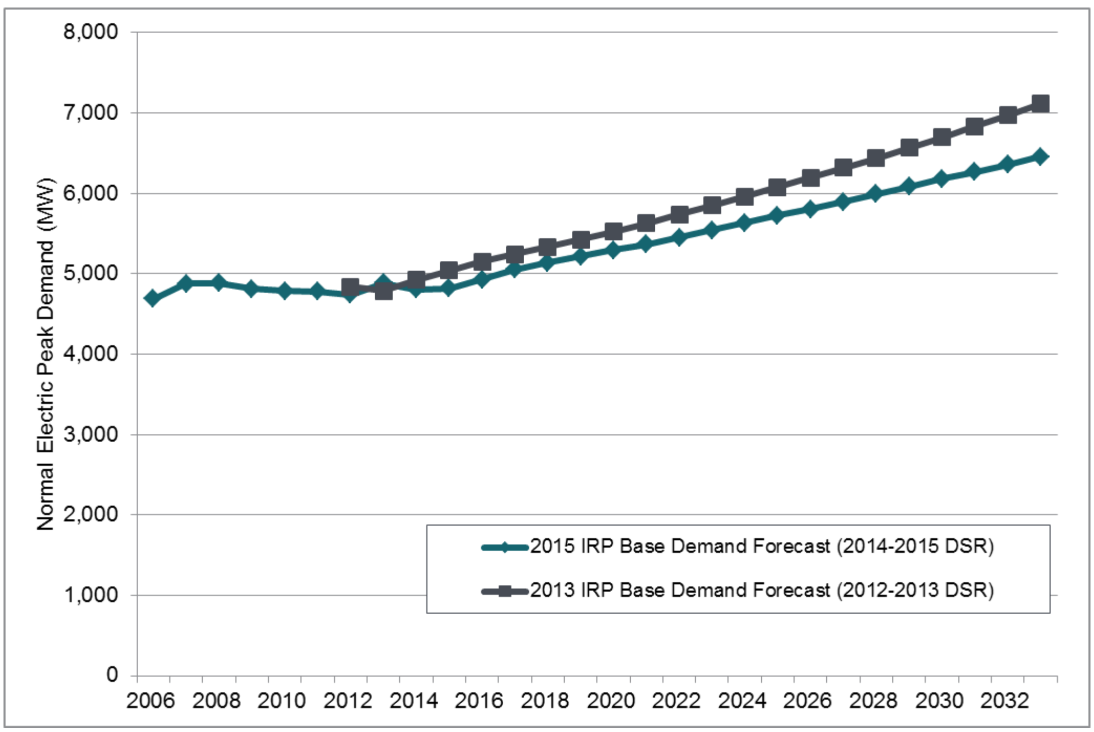


Figure 5-20: Electric Peak Demand Forecast before DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (23 Degrees, MW)

ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW)						
Scenario	2016	2020	2025	2030	2035	AARG (2016-2035)
2015 IRP Base Demand Forecast	4,929	5,294	5,726	6,180	6,649	1.6%
2015 IRP High Demand Forecast	5,187	5,608	6,200	6,734	7,544	2.0%
2015 IRP Low Demand Forecast	4,701	5,013	5,340	5,693	5,887	1.2%

Figure 5-21: Electric Peak Demand Forecast before DSR
2015 IRP Base Scenario versus 2013 IRP Base Scenario
Hourly Annual Peak (23 Degrees, MW)



System-level Impacts of Conservation. The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2014 and 2015, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2016 to the end of the forecast.

However, we also examine the effects of conservation on the system load and peak forecasts over the 20-year planning horizon. This forecast is used internally at PSE for financial planning and for transmission and distribution system planning. We apply the demand-side resources from the 2013 IRP to the Base scenario load and peak forecasts for 2016 to 2035. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation was also applied for that period. The result is illustrated in Figures 5-21 and 5-22, below.

DSR IMPACT ON LOAD: When 2013 IRP DSR is applied to the load forecast:

- Total system demand is 2,606 aMW in 2016 increasing to 3,022 aMW in 2035.
- Average annual growth is 0.2 percent from 2016 to 2025 and 1.3 percent from 2025 to 2035. Load grows more slowly in the first half of the forecast because that is when the majority of the demand-side measures are expected to be implemented.

DSR IMPACT ON PEAK: When the 2013 IRP DSR is applied to the peak forecast:

- The system peak is 4,844 MW in 2016 increasing to 5,719 MW in 2035.
- Average annual growth is 0.4 percent per year from 2016 to 2025 and 1.3 percent from 2025 to 2035. Again, peak load grows more slowly in the first 10 years when DSR is more heavily concentrated.

The 2015 IRP DSR is higher than the 2013 IRP DSR. Therefore we would expect the Electric Base Demand Forecast with 2015 IRP DSR to be lower than what is shown in Figure 5-22 and Figure 5-23.

Figure 5-22: 2015 IRP Electric Base Demand Forecast (aMW), before DSR and after applying 2013 IRP DSR

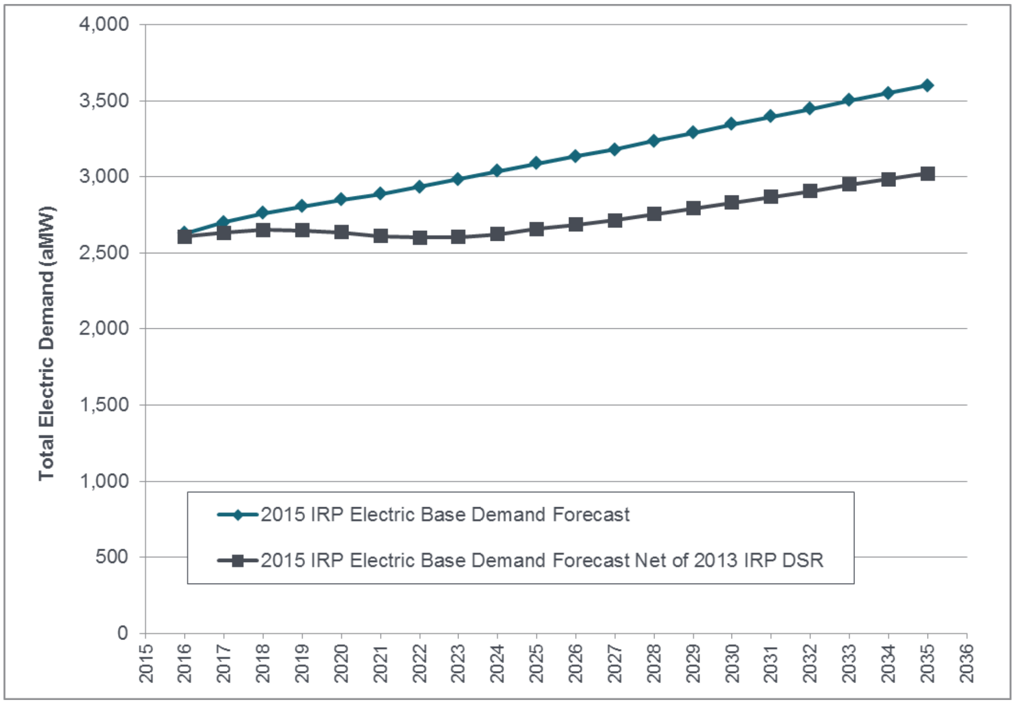
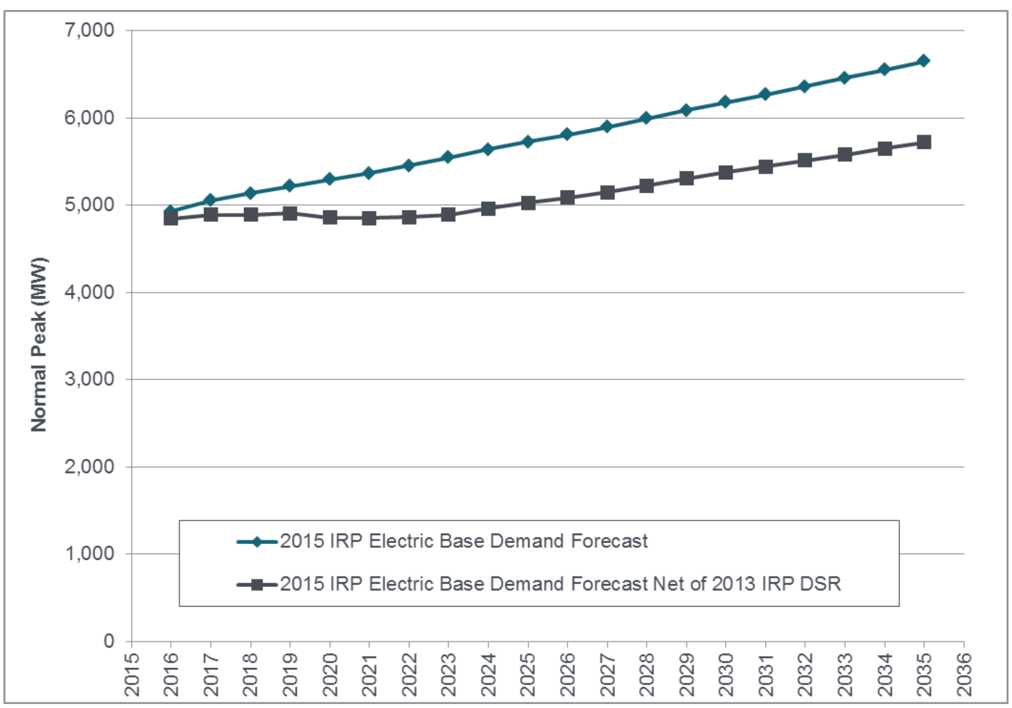


Figure 5-23: Electric Peak Base Demand Forecast (MW), before DSR and after applying 2013 IRP DSR



Electric Customer Counts. System-level customer counts are expected to grow by 1.5 percent per year on average, from 1.1 million customers in 2016 to 1.5 million customers in 2035. This growth rate is slightly lower than the 2013 IRP Base Demand Forecast growth rate of 1.7 percent, due to the lowered population forecast. Also, continuing weakness in the housing market recovery in recent years led to a lower starting point in the 2016 customer forecast for this IRP compared to the 2013 IRP forecast.

Residential customers are driving the customer count increase; they represent 88 percent of the PSE's electric customers in 2016. The next largest group, commercial customers, is expected to grow at an annual rate of 1.4 percent from 2016 to 2035. Industrial customer counts are expected to decline, following a historical trend. These trends are expected to continue as the economy in PSE's service territory grows more commercial and less industrial.

Figure 5-24: December Electric Customer Counts by Class, 2015 IRP Base Demand Forecast

DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST						
Class	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
Total	1,132,928	1,205,903	1,307,161	1,409,007	1,507,494	1.5%
Residential	996,090	1,060,975	1,152,211	1,243,344	1,330,000	1.5%
Commercial	126,580	134,116	143,527	153,569	164,560	1.4%
Industrial	3,387	3,304	3,201	3,101	3,004	-0.6%
Other	6,871	7,508	8,222	8,993	9,929	2.0%

Figure 5-25: Electric Demand by Class, 2015 IRP Base Demand Forecast before DSR

ELECTRIC LOAD BY CLASS, BASE DEMAND FORECAST (aMW)						
Class	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
Total	2,629	2,850	3,088	3,345	3,598	1.7%
Residential	1,224	1,319	1,439	1,559	1,664	1.6%
Commercial	1,071	1,190	1,297	1,420	1,556	2.0%
Industrial	142	133	128	123	118	-1.0%
Other	11	11	11	12	12	0.4%
Losses	181	197	213	231	248	1.7%

Electric Use per Customer. Residential use per customer is expected to be flat in the future, absent the impacts of demand-side resources. Multifamily housing growth and the increasing use of natural gas for space and water heating will tend to reduce electric use per customer, but this should be balanced by growth in plug loads and declining or flat real electric rates. As the economy recovers from the recession, commercial use per customer is expected to rise slowly due to higher employment levels and lower vacancy rates in the near term.

Figure 5-26: Electric Use per Customer 2015 IRP Base Demand Forecast before DSR

ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh)						
Type	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
Residential	10.9	11.0	11.0	11.1	11.0	0.07%
Commercial	74.7	78.3	79.6	81.4	83.3	0.57%
Industrial	367	352	349	347	343	-0.34%

County-level Electric Forecasts

All of the county-level and sub-county-level forecasts shown below include the impacts of the 2013 IRP demand-side resources. County-level forecasts extend only to 2031.

King County is the most rapidly growing part of PSE's service territory. In 2014, it accounted for about 50 percent of PSE's normal electric peak load. Between 2016 and 2031, it is expected to add 176,000 customers and experience an average customer growth rate of 1.9 percent per year. It is also expected to account for 64 percent of PSE's future electric peak load growth, with the addition of 386 MW between 2016 and 2031.

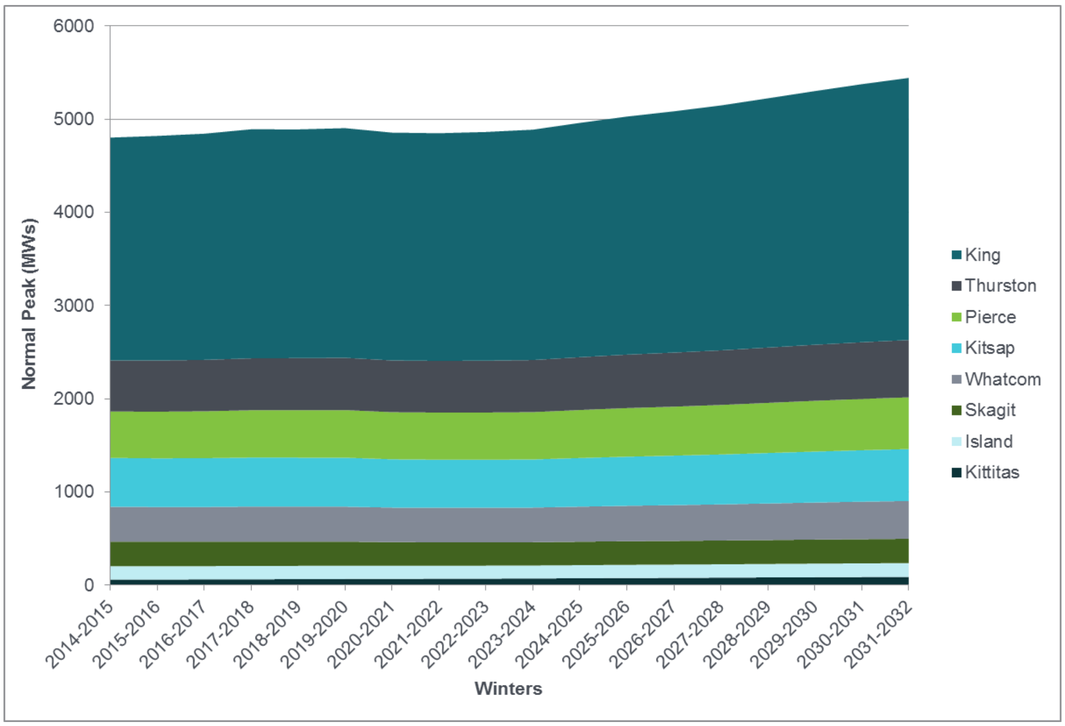
Average annual customer growth rates for the other counties are as follows:

- Thurston County: 1.4 percent
- Pierce County: 1.3 percent
- Whatcom, Skagit, Island and Kitsap Counties range from 0.8 to 1.2 percent per year on average.
- The county with the fewest PSE customers, Kittitas, is expected to grow from 13,800 to 22,300 customers between 2016 and 2031.

In terms of peak load growth:

- Thurston, Pierce and Whatcom Counties are expected to grow between 0.6 and 0.7 percent annually between 2016 and 2031.
- Kitsap and Island Counties are expected to grow 0.4 percent and 0.3 percent annually, respectively.
- Kittitas County is expected to grow at 2.6 percent but will only account for 5 percent of the peak load growth from 2016 to 2031.

Figure 5-27: Electric Peak Forecasts by County (MW), after applying 2013 IRP DSR



Eastside Area Electric Forecast

PSE updated its Eastside Area peak demand forecast using recent information and external input forecasts to better understand the diversity of loads in the PSE electric service territory as well as to better understand when the Energize Eastside project is needed. Figure 5-28 illustrates the forecast normal peak load growth in the Eastside Area before DSR and after DSR, along with an extreme peak load forecast after DSR. Figure 5-29 shows the growth rate before DSR is 3.1 percent – nearly twice the 1.6 percent growth rate of the system-level forecast before DSR, shown in Figure 5-20.

Figure 5-28: Eastside Area, Electric Winter Peak Forecasts (MW)

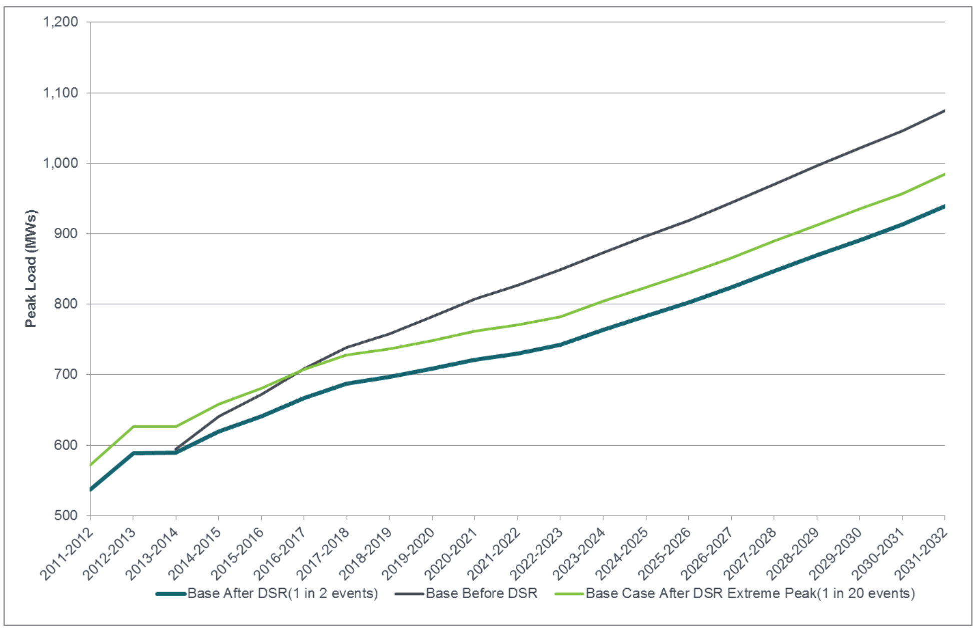


Figure 5-29: Eastside Area, Electric Normal Winter Peak Growth Forecast (Table)

	2014-2024		2014-2031	
SCENARIOS	Average Annual Rate of Growth	Demand Change	Average Annual Rate of Growth	Demand Change
Base After DSR	2.4%	164	2.5%	320
Base (no DSR)	3.4%	256	3.1%	435
Base (extreme peak)	2.3%	166	2.4%	327

GAS DEMAND FORECAST

Highlights of the system-level base, high and low demand forecasts developed for PSE's gas sales service are presented below. The gas demand forecasts include only demand-side resources implemented through December 2015, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Gas Load Growth. The 2015 IRP Gas Base Demand Forecast is a forecast of both firm and interruptible loads, because this is the volume of natural gas that PSE is responsible for securing and delivering to customers. For distribution planning, however, transport loads must be included in total load; transport customers purchase their own natural gas, but contract with PSE for delivery.

In the 2015 IRP Base Demand Forecast, load is projected to grow 1.7 percent per year on average from 2016 to 2035; this would increase load from around 99,000 Mdth in 2016 to 137,000 Mdth in 2035. This rate of load growth is slightly lower than the 2013 IRP Base Demand Forecast, which had an annual growth rate of 1.8 percent (2014 to 2033).

The 2015 IRP High Gas Demand Forecast projects an average annual growth of 2.1 percent; the Low Demand Forecast projects a growth rate of 1.4 percent per year.

Figure 5-30: Gas Demand Forecast before DSR
Base, High and Low Scenarios, without Transport Load (Mdth)

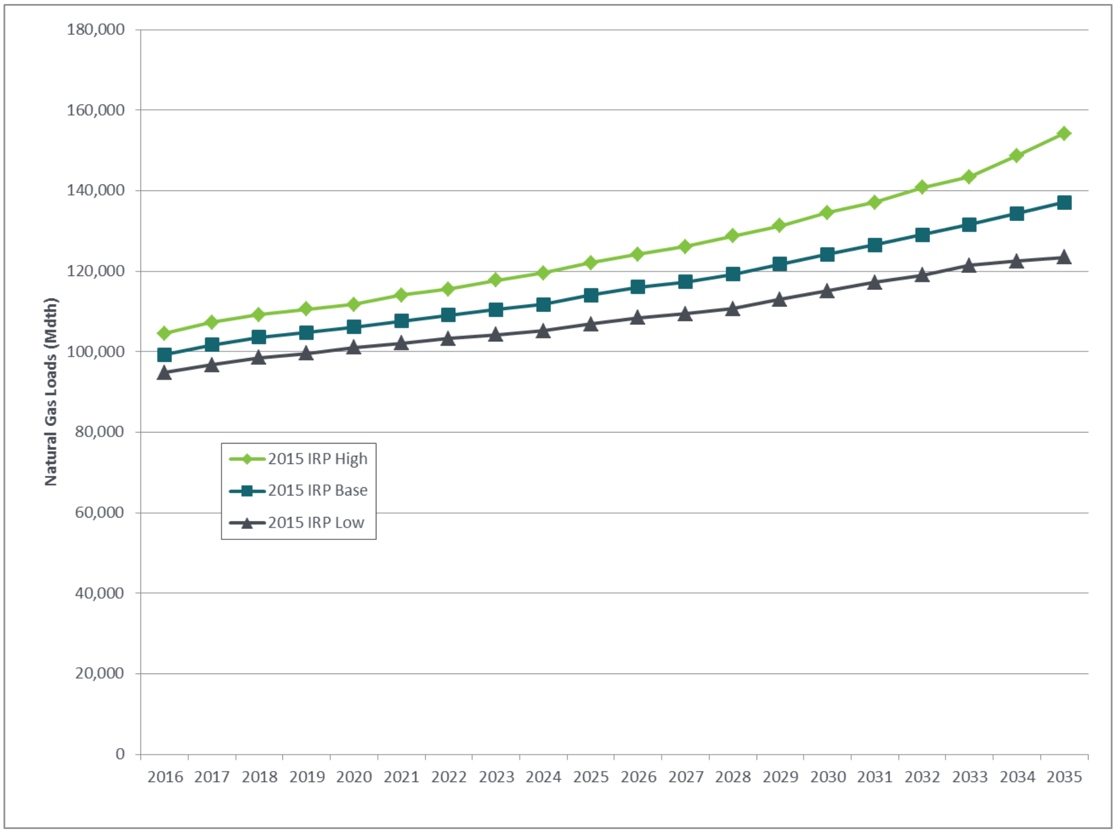


Figure 5-31: Gas Demand Forecast before DSR (Table)
Base, High and Low Scenarios without Transport Load (Mdth)

GAS LOAD FORECAST SCENARIOS (Mdth), WITHOUT TRANSPORT						
Scenario	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
2015 IRP Base Demand Forecast	99,232	106,171	114,010	124,200	137,126	1.7%
2015 IRP High Demand Forecast	104,603	111,745	122,075	134,536	154,183	2.1%
2015 IRP Low Demand Forecast	94,803	101,057	106,884	115,163	123,459	1.4%

Gas Peak Demand. The gas design peak day is modeled at 13 degrees Fahrenheit average temperature for the day, and the curtailment of interruptible gas volumes was included when forecasting peak gas loads.

For peak gas demand, the 2015 IRP Base Demand Forecast projects an average increase of 1.8 percent per year for the next 20 years; peak demand would rise from 1,008 Mdth in 2016 to 1,427 Mdth in 2035. The High Demand Forecast projects a 2.1 percent annual growth rate, and the Low Demand Forecast projects 1.6 percent. The 2015 IRP Base Demand growth rate is slightly lower than the 2013 IRP Base Demand growth rate of 2.0 percent (2014 to 2033), mainly due to the lower customer forecast; however, it starts out higher than the previous forecast because lower retail gas rates have caused an increase in use per customer at the beginning of the study period. Over time, the two forecasts come back together because of the slower customer growth in the 2015 IRP Base Demand Forecast.

Gas peak day growth rates are slightly higher than the rates for load growth because the classes that contribute most to peak demand (the weather-sensitive residential and commercial sectors) are growing faster than the classes that don't contribute to peak demand. Rising baseloads are also contributing to peak demand because gas is increasingly being used for purposes other than heating (such as cooking, clothes drying and fireplaces). This effect is slightly offset by higher appliance and home efficiencies.

Figure 5-32: Gas Peak Day Demand Forecast before DSR
Base, High and Low Scenarios (13 Degrees, Mdth)

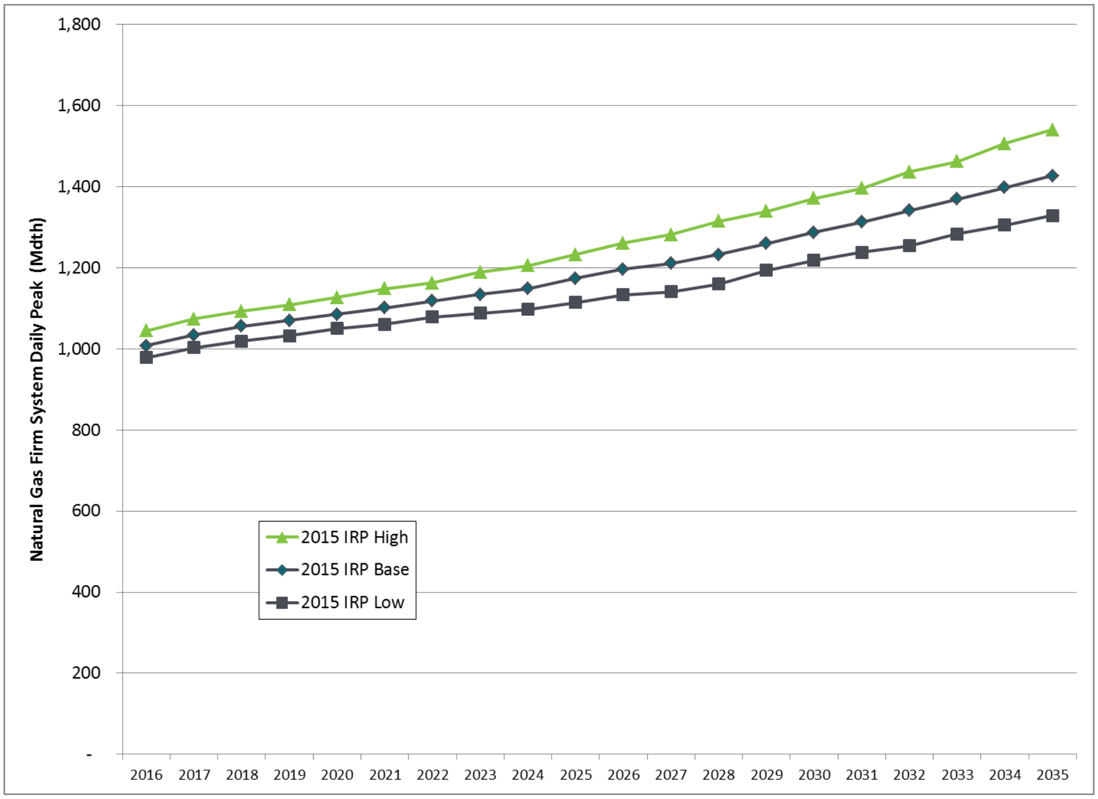
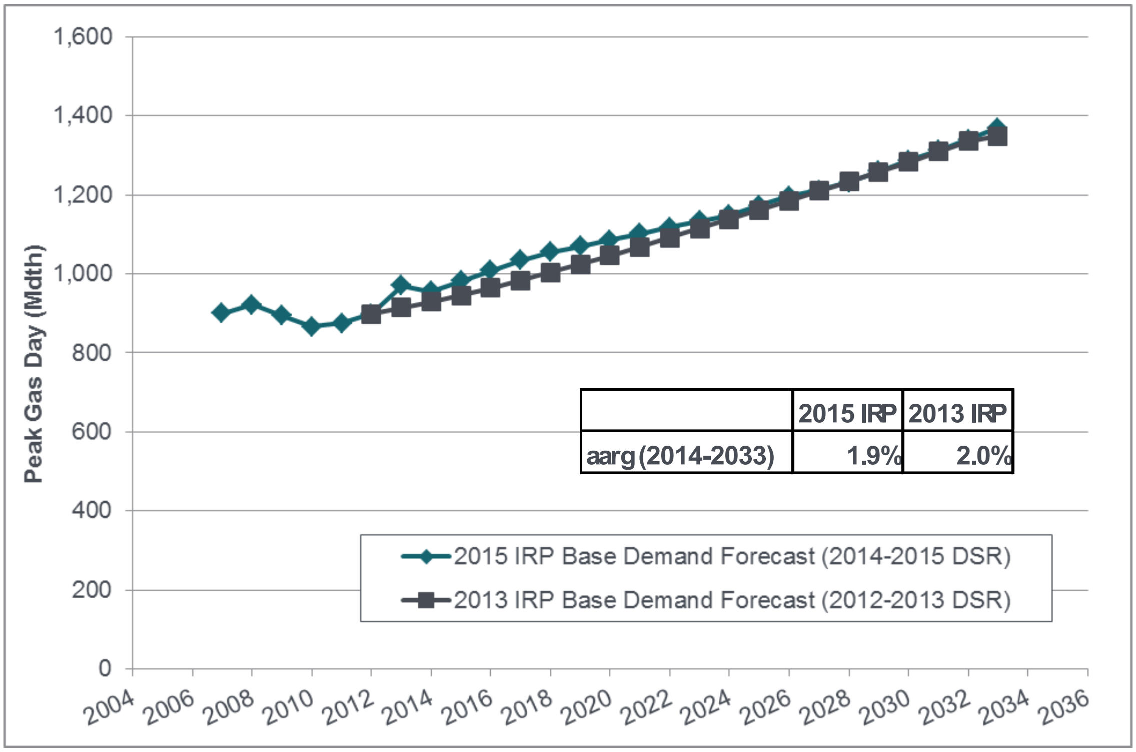


Figure 5-33: Gas Peak Day Demand Forecast before DSR (Table)
Base, High and Low Scenarios (13 Degrees, Mdth)

FIRM GAS PEAK DAY FORECAST SCENARIOS (Mdth)						
Scenario	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
2015 IRP Base Demand Forecast	1,008	1,085	1,173	1,287	1,427	1.8%
2015 IRP High Demand Forecast	1,044	1,126	1,232	1,371	1,541	2.1%
2015 IRP Low Demand Forecast	978	1,050	1,114	1,218	1,329	1.6%

Figure 5-34: Firm Gas Peak Day Forecast before DSR
2015 IRP Base Scenario versus 2013 IRP Base Scenario
Daily Annual Peak (13 Degrees, Mdth)



	2015 IRP	2013 IRP
aarg (2014-2033)	1.9%	2.0%

System-level Impacts of Conservation. As explained at the beginning of the chapter, the gas demand forecasts include only demand-side resources implemented through December 2015, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of conservation on the system load and peak forecasts, the full amount of DSR from the 2013 IRP is applied to the total system load and peak forecast for 2016 to 2035. This forecast is used internally at PSE for financial and system planning decisions.

When 2013 IRP DSR is applied:

- Total system load grows at an average annual rate of 0.9 percent from 2016 to 2025 and 1.5 percent from 2025 to 2035; volume (including transport classes) rises from 122,000 Mdth in 2016 to 154,000 Mdth in 2035. Load grows more slowly in the first half of the forecast because that's when the majority of the demand-side measures are expected to be implemented.
- The design system peak is expected grow at an average annual rate of 1.5 percent from 2016 to 2025 and 2.0 percent from 2025 to 2035. Again, peak load grows more slowly in the first half of the forecast because that is when the majority of the demand-side measures are expected to be implemented.

The 2015 IRP DSR has a lower energy contribution but a higher peak contribution compared to the 2013 IRP DSR. So, if the Gas Base Demand Forecast (which represents annual energy need) were to be updated with the 2015 IRP DSR, we would expect the result to be higher than what is shown in Figure 5-35; and if the Gas Peak Day Base Demand Forecast were to be updated with 2015 IRP DSR, we would expect a result lower than what is shown in Figure 5-36.

Figure 5-35: 2015 IRP Gas Base Demand Forecast,
Before DSR and after applying 2013 IRP DSR

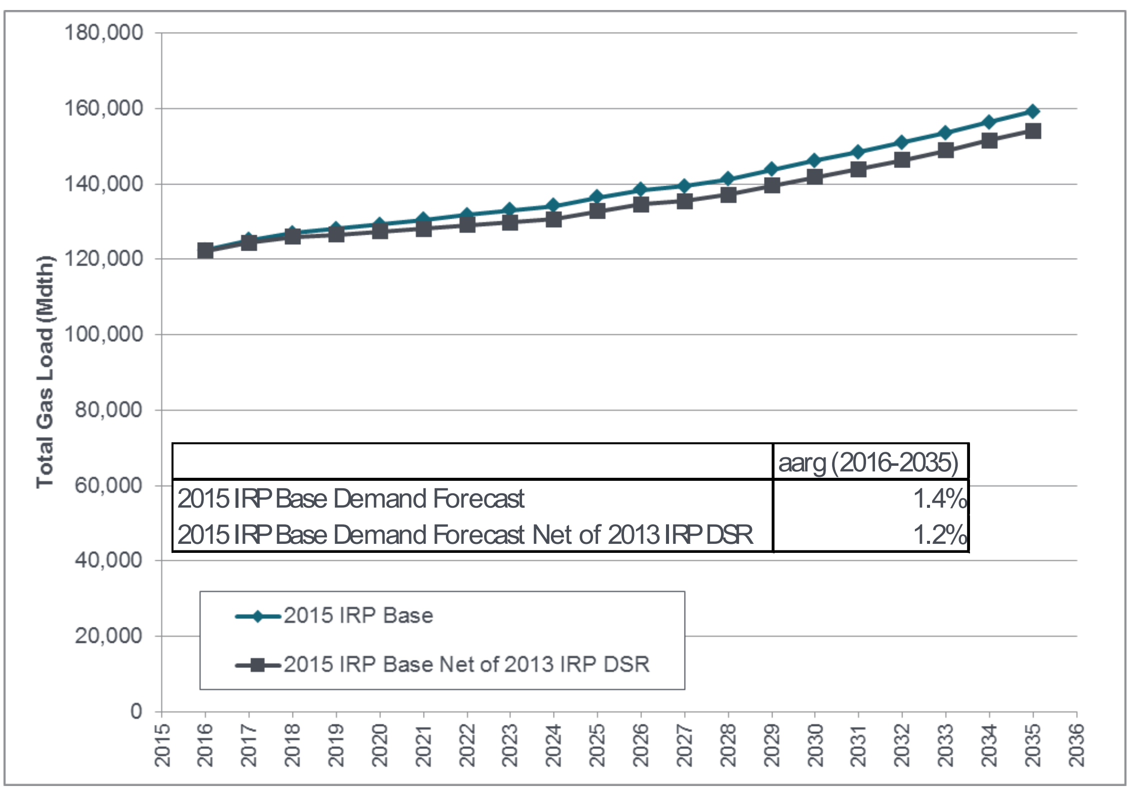
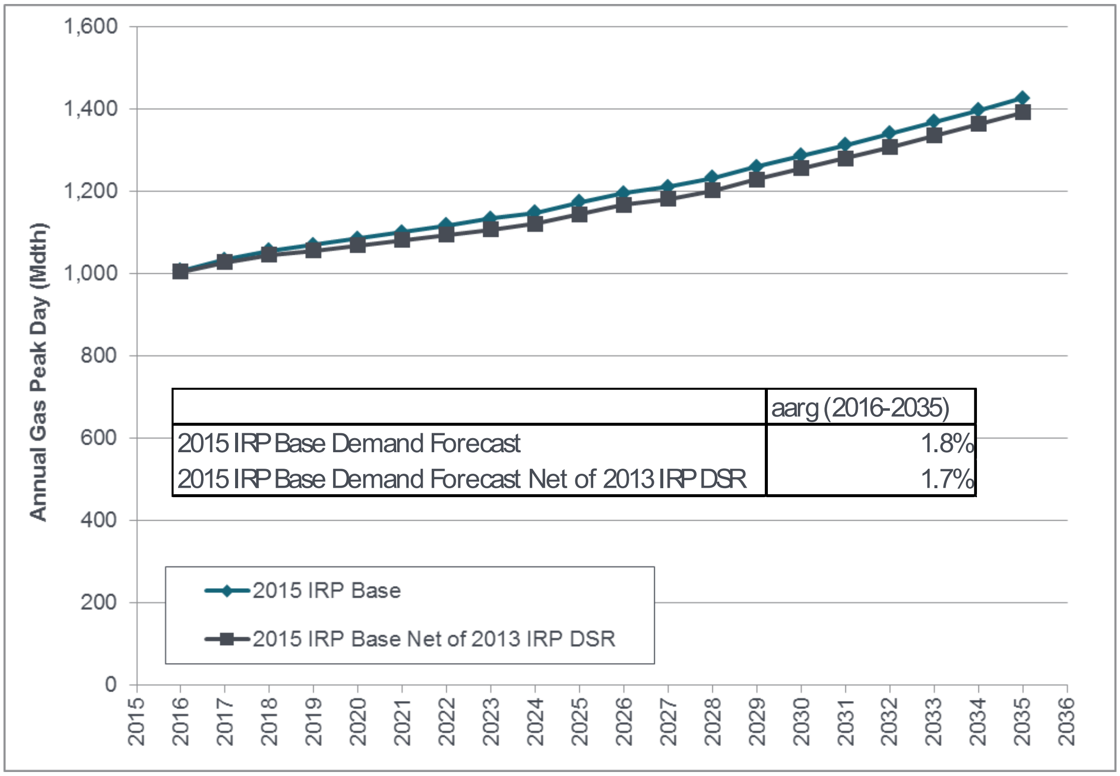


*Figure 5-36: 2015 IRP Gas Peak Day Base Demand Forecast,
Before DSR and after applying 2013 IRP DSR*



	aarg (2016-2035)
2015 IRP Base Demand Forecast	1.8%
2015 IRP Base Demand Forecast Net of 2013 IRP DSR	1.7%

Gas Customer Counts. The Base Demand Forecast projects natural gas customer counts will increase at a rate of 1.9 percent per year on average between 2016 and 2035, reaching almost 1.2 million customers by the end of the forecast period for the system as a whole. A lower population forecast has resulted in a lower growth rate than the system growth rate of 2.3 percent projected in the 2013 IRP (2014 to 2033).

Residential customer counts drive the growth in total customers, since this class makes up 93 percent of PSE's gas sales customers. The next largest group, commercial customers, is expected to grow at an annual rate of 1.6 percent from 2016 to 2035. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Figure 5-37: December Gas Customer Counts by Class, from 2015 IRP Base Demand Forecast

DECEMBER GAS CUSTOMER COUNTS BY CLASS FROM 2015 IRP BASE DEMAND FORECAST						
Customer Type	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
Residential	763,406	819,348	893,618	988,150	1,095,795	1.9%
Commercial	57,232	61,173	66,237	71,676	77,672	1.6%
Industrial	2,306	2,189	2,050	1,920	1,798	-1.3%
Total Firm	822,944	882,711	961,906	1,061,746	1,175,266	1.9%
Interruptible	283	248	217	193	175	-2.5%
Total Firm & Interruptible	823,227	882,959	962,123	1,061,939	1,175,441	1.9%
Transport	208	208	208	208	208	0.0%
System Total	823,435	883,167	962,331	1,062,147	1,175,649	1.9%

Gas Use per Customer. Residential use per customer is relatively flat, showing a -0.1 percent average annual growth for the forecast period. Commercial use per customer is expected to rise 0.4 percent annually over the forecast horizon. Industrial use per customer has been declining in recent years, but lower gas prices increase use somewhat, keeping industrial usage essentially flat.

Figure 5-38: Gas Use per Customer, 2015 IRP Gas Base Demand Forecast before DSR

USE PER CUSTOMER (THERMS) FROM 2015 IRP GAS BASE DEMAND FORECAST						
Customer	2016	2020	2025	2030	2035	AARG 2016-2035
Residential	827	826	814	808	812	-0.1%
Commercial	4,920	5,021	5,110	5,211	5,346	0.4%
Industrial	11,696	11,870	11,946	11,909	11,781	0.0%

Gas Load by Class. Total system load, including transport load, is expected to increase at a rate of 1.4 percent annually between 2016 and 2035. Residential loads, which represent 51 percent of load in 2016, are expected to increase by 1.8% annually during the forecast period. Commercial loads, which represent 23 percent of 2016 load, are expected to increase 2.0 percent annually.

Population growth and electric-to-gas conversions are driving residential load growth. Commercial load growth is driven by increases in both customer counts and use per customer. Some sectors, among them industrial, interruptible and transport, are expected to decline slightly, continuing a more than decade-long trend of slowing manufacturing employment.

Figure 5-39: Gas Loads by Class (Mdth), 2015 IRP Gas Base Demand Forecast before DSR

LOAD (Mdth) BY CLASS FROM 2015 IRP GAS BASE DEMAND FORECAST						
Class	**2016**	**2020**	**2025**	**2030**	**2035**	**AARG 2016-2035**
Residential	62,694	67,192	72,215	79,167	88,098	1.8%
Commercial	28,317	30,871	33,958	37,414	41,510	2.0%
Industrial	2,729	2,631	2,480	2,317	2,148	-1.3%
Total Firm	93,741	100,694	108,653	118,897	131,756	1.8%
Interruptible	4,698	4,627	4,445	4,309	4,272	-0.5%
Total Firm and Interruptible	98,439	105,322	113,098	123,206	136,029	1.7%
Transport	23,064	22,842	22,219	21,772	21,835	-0.3%
System total before losses	121,503	128,164	135,316	144,979	157,863	1.4%
Losses	980	1,034	1,091	1,169	1,273	1.4%
System Total	122,483	129,198	136,408	146,148	159,137	1.4%

ELECTRIC ANALYSIS

Contents

The electric analysis in the 2015 IRP explores long-range planning issues related to supply-side resources, conservation, carbon reduction, emerging resources and wholesale market risk. In this IRP, we update our planning standard. We also include wholesale market risk in the analysis for the first time. Wholesale market purchases have been a significant component of PSE's least cost portfolios for the past decade, but now that the region is forecasted to shift from capacity surplus to deficit in the coming decade unless new resources are added,[1] that strategy needs to be reevaluated. Continuing the current level of reliance on wholesale market purchases could expose PSE and its customers to unreasonable levels of physical and financial risk.

1 / Refer to Appendix F for the regional resource adequacy studies produced by NPCC, BPC and PNUCC.

ANALYSIS OVERVIEW

The electric analysis in the 2015 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

- PSE updated its electric planning standard based on the benefits and costs of reliability from our customers' perspective.
- The peak capacity value of wholesale market purchases was reassessed to incorporate wholesale market reliability risk.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 4 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 5 presents the 2015 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.
- In some scenarios, CCCT plants were more cost effective than CT's with a combination of firm pipeline capacity and oil backup, but in other scenarios, the CT's were lower cost. Therefore, we developed six candidate resource portfolios based on different strategies, to examine in the stochastic risk analysis.

4. Stochastic Risk Analysis of Candidate Resource Strategies

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how the different candidate strategies 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 six candidate resource strategies 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.

- 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.

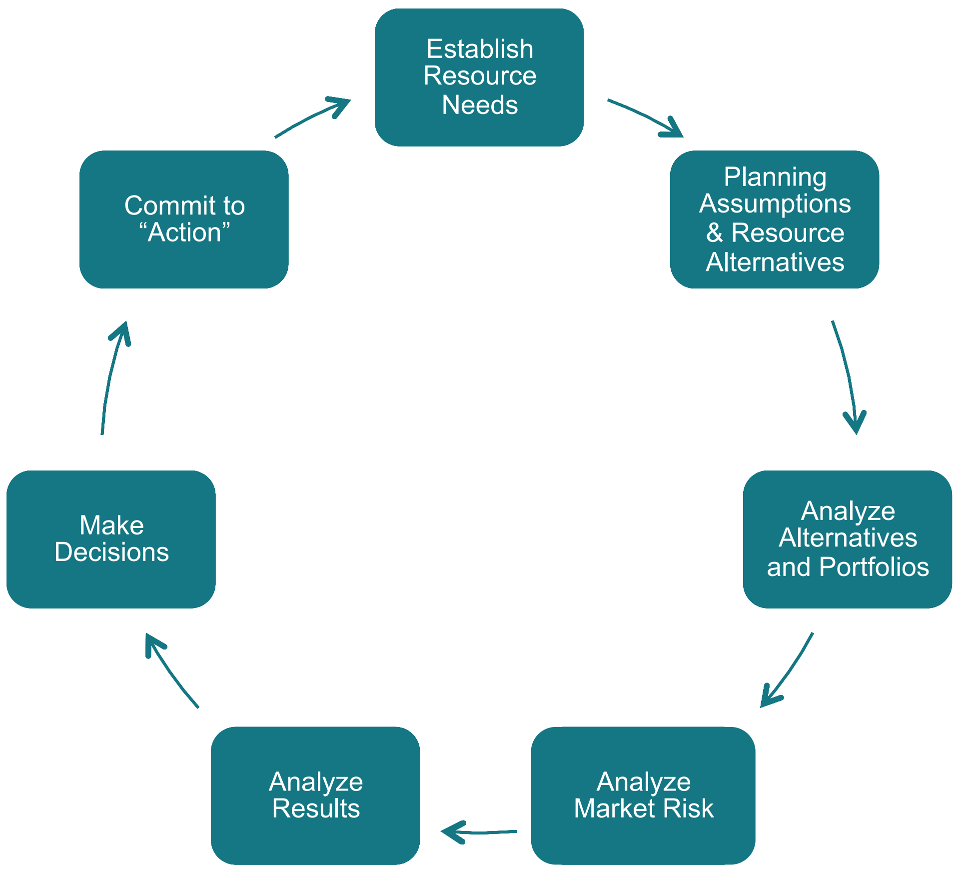
7. Commit to Action

Resource decisions are not made in the IRP. What we learn from this 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: 2015 IRP Process



RESOURCE NEED

PSE expanded its analysis of resource need in two areas for this IRP. First, we examined updating PSE's planning standard to better reflect the value of reliability to customers; and second, we reassessed the peak capacity value of PSE's wholesale market purchases in order to reflect the reliability risk created by the changing load/resource balance in the Pacific Northwest. These adjustments are discussed first, since both impact the determination of peak capacity need.

Updating the Planning Standard

Basing the Planning Standard on Benefit/Cost Analysis
This IRP adopts an optimal planning standard that reflects a benefit/cost analysis designed to minimize the net cost of reliability to customers. The analysis also incorporates wholesale market risk in its peak capacity assessment of wholesale market purchases, consistent with regional resource adequacy assessments. The updated standard and incorporation of market risk reduces the expected value of lost load to customers by $130 million per year. The cost to achieve that expected savings is $63 million per year, for a net benefit to customers of $67 million per year. Risk reduction is dramatic. The $63 million per year cost reduces the risk to customers by $1.3 billion per year.

Incorporating Wholesale Market Purchase Risk
Since regional resource adequacy studies forecast a shift from surplus to deficit in the region's load/resource balance, this a particularly appropriate time for PSE to incorporate wholesale market risk into its IRP analysis. Prior IRPs also assumed wholesale market purchases were 100 percent reliable, but this is no longer a reasonable assumption now that the capacity surplus in the region is shrinking. Therefore, PSE incorporates wholesale market risk into its updated capacity planning standard.

Summary of Planning Standard Changes. Figure 6-2, Summary of Planning Standard Changes, provides information that will be used in the discussion below. Additional detail is included in Appendix G, Wholesale Market Risk, and Appendix N.

Figure 6-2: Summary of Planning Standard Changes

		Reliability Metric		2021 Peaker Capacity Added after DSR (MW)	Customer Value of Lost Load	
		LOLP	EUE (MWh)		Expected ($mill/yr)	TVar90 ($mill/yr)
1	2013 Planning Standard with No Market Risk	5%	26	(150)	86*	858*
2	2013 Planning Standard with Market Risk	5%	50	(117)	169	1,691
3	2015 Optimal Planning Standard (Includes Market Risk)	1%	10.9	234	39	385

* *Inaccurate estimate because it ignores reliability impact of wholesale market risk.*

2015 Optimal Planning Standard versus 2013 Planning Standard.

To understand the impact of the change to PSE's capacity planning standard in this IRP, it is helpful to understand what the reliability metrics in the table in Figure 6-2 represent. Loss of load probability (LOLP) is a measure of the likelihood of a load curtailment occurring; expected unserved energy (EUE) is a measure of the magnitude of potential load curtailments, in other words, how much load and how many customers are likely to be impacted.

The 2013 Planning Standard called for maintaining enough peak capacity to achieve a 5 percent loss of load probability (LOLP). This is a reasonable, industry-standard approach, adopted by the Northwest Power and Conservation Council (NPCC) for its regional resource adequacy assessment and adopted by PSE in 2009, but it is not tied to the value of reliability to customers. That is, the 5 percent LOLP does not explicitly consider the value of reliability to customers or the cost to provide that reliability. This IRP focuses on those tradeoffs, so that we can be sure we are providing the optimal balance of cost and risk to our customers. In addition, the 2013 Planning Standard did not incorporate PSE's wholesale market purchase risk.

2015 Optimal Planning Standard

- Determined by benefit/cost analysis focused on the value of reliability to customers
- Includes wholesale market purchase risk

2013 Planning Standard

- Focused on a 5 percent LOLP target
- Does not incorporate wholesale market purchase risk.

In line one of Figure 6-2, the 2013 Planning Standard – which is focused on a 5 percent LOLP and ignores market risk – indicates that PSE would be surplus 150 MW in 2021. In line two, when the 2013 standard includes market risk, the surplus diminishes to 117 MW. From this perspective, recognizing market risk would require PSE to add 33 MW to maintain the 5 percent LOLP. However, the real impact of ignoring risk can be seen in the EUE and customer value of lost load sections on these two lines. Recognizing market risk nearly doubles EUE, the customer value of lost load and risk. EUE increases from 26 MWh to 50 MWh; the expected customer value of lost load increases from $86 million to $169 million; and risk increases from $858 million to $1,691 million.

These results highlight the need for a new planning standard. Focusing only on LOLP misses the fact that customer curtailment volumes would be almost twice as high. In addition, achieving a specified LOLP target (by adding new generating capacity) does not ensure that the additional cost of increasing system reliability is balanced against the additional value gained by customers. Clearly, a more comprehensive approach to defining the planning standard is needed.

In developing the 2015 Optimal Planning Standard, we focused on the benefits and costs to customers of improving reliability. Translating MWh of lost load into a dollar metric based on its value to customers facilitated performing a benefit/cost analysis to define the optimal planning standard. The word "optimal" is used here in an economic context. The analysis compared the cost to customers of potential outages with the cost of adding generating resources to increase service reliability to find the "optimal" level of reliability – the point at which the benefit to customers of increased reliability (marginal benefit) is equal to the cost of providing that level of reliability (marginal cost).

Again, Figure 6-2 shows that moving to the 2015 Optimal Planning Standard reduces the expected value of lost load to customers by $130 million per year.[2] The cost to achieve that expected savings is $63 million per year,[3] for a net benefit to customers of $67 million per year. Risk reduction (as measured by the TailVar90 metric) to customers is dramatic. That $63 million per year in new resource costs reduces the risk to customers by $1.3 billion per year.[4]

2 / From Figure 2-1. This is calculated by comparing the Expected VOLL in line 2 (2013 Planning Standard Including Market Risk) with the Expected VOLL in line 3 (2015 Optimal Planning Standard): $169 million - $39 million = $130.
*3 / This value is derived by first calculating the difference between the surplus of 117 MW in line 2 (2013 Planning Standard Including Market Risk) and the need (deficit) of 234 MW in line 3 (2015 Optimal Planning Standard). This value is then multiplied by the levelized cost of a peaker, estimated from the portfolio model at $0.18 million per MW per year. So: 234 MW – (-117 MW) = 351 MW. Then: 351 MW * $0.18 million per MW per year = $63 million per year.*
4 / $1,691 million - $385 million = $1,306 million

Incorporating Wholesale Market Reliability Risk

In this IRP, PSE incorporates wholesale market risk for the first time. This change is directly related to the pending retirement of two regional coal plants and the shifting load/resource balance in the Pacific Northwest.

Time for a Change. PSE has essentially ignored market risk in prior IRP analyses, because we have been able to rely on wholesale market purchases as a least-cost way of meeting physical need with a high degree of confidence that wholesale power would be available for purchase in the future whenever it was needed. Although studies demonstrated that technically regional capacity wouldn't be sufficient in all circumstances, PSE assumed wholesale markets were 100 percent reliable due to ongoing regional capacity surpluses. We understood that such an optimistic assumption was not sustainable indefinitely, but as long as the region was meeting regional resource adequacy metrics, this strategy made sense for our customers. Refining that assumption becomes a high priority now that studies indicate the region will fail to meet acceptable resource adequacy metrics by 2021.[5]

This is important, because short-term wholesale market purchases are the single largest category in PSE's current resource portfolio. They account for up to 1,666 MW, or approximately 28 percent, of the resources we use to meet our peak capacity need. And, since PSE is one of the largest purchasers of winter capacity in the region, our customers would be especially exposed during regional curtailment events, because large portions of the capacity that PSE has counted on to purchase may simply not be available as surpluses shrink.

5 / The regional studies on load/resource balance conducted by NPCC, PNUCC and BPA (or links to them) appear in Appendix F. Appendix G explains how these studies were used in PSE's wholesale market risk analysis.

Assumptions Regarding Regional Resource Configurations.

Incorporating wholesale market risk into the 2015 IRP analysis required us to make certain assumptions regarding regional resource configurations. We began with the assumptions incorporated into the May 2015 NPCC regional resource adequacy study, and made three key adjustments.

Southwest imports were increased by 475 MW.

The NPCC's base analysis assumes 3,400 MW of transmission capacity is available from California, but only 2,925 MW of winter season on-peak resources were included in the NPCC's analysis (2,500 MW of spot market purchases plus 425 MW of long-term contracts). We added the spot market import amounts necessary such that total imports from California equal 3,400 MW on all hours. It seemed reasonable to assume that this additional capacity would be available during the region's peak need season.

Regional generation was increased by 440 MW.

Portland General Electric (PGE) has plans to acquire 440 MW of firm generation by 2021, when their Boardman coal plant retires. Information from PGE demonstrates a strong preference for that generation to be a non-intermittent renewable resource. PGE is, however, prepared to build Carty 2, which would be a 440 MW gas CCCT plant if adequate renewable resources are not available. This plant did not meet the criteria to include in the NPCC's regional adequacy analysis, but it seems reasonable to assume that it will be built, and we did not want to overstate our resource needs.

Regional generation was reduced by 650 MW.

This adjustment assumes the 650 MW Grays Harbor CCCT is not available to operate during PNW load curtailment events. This gas-fired generating plant appears to rely solely on wholesale market purchases of interruptible fuel supply. It has neither firm pipeline capacity for natural gas fuel supply nor oil backup, which means that under extreme cold weather conditions – when the region is most likely to have a capacity deficit – the plant may not be able to operate until weather conditions improve and wholesale market gas supplies are available again. The NPCC assumed firm fuel supply in its regional adequacy analysis because of the difficulty of determining when the plant might be unable to obtain supplies, but it would be inconsistent for PSE to include it in our regional resource configuration since we would not be able to consider it firm for our customers if it were in our portfolio.

Benefit/Cost Analysis. The benefit cost analysis establishes the optimal capacity addition to meet the optimal customer reliability level.

Figure 6-3 compares the results of the benefit/cost analysis for four different capacity addition amounts ranging in size from 0 MW to 300 MW. This table also illustrates that the optimal 2021 planning margin is achieved with a capacity addition of 234 MW (i.e., the point at which the benefit/cost ratio is 1.0).

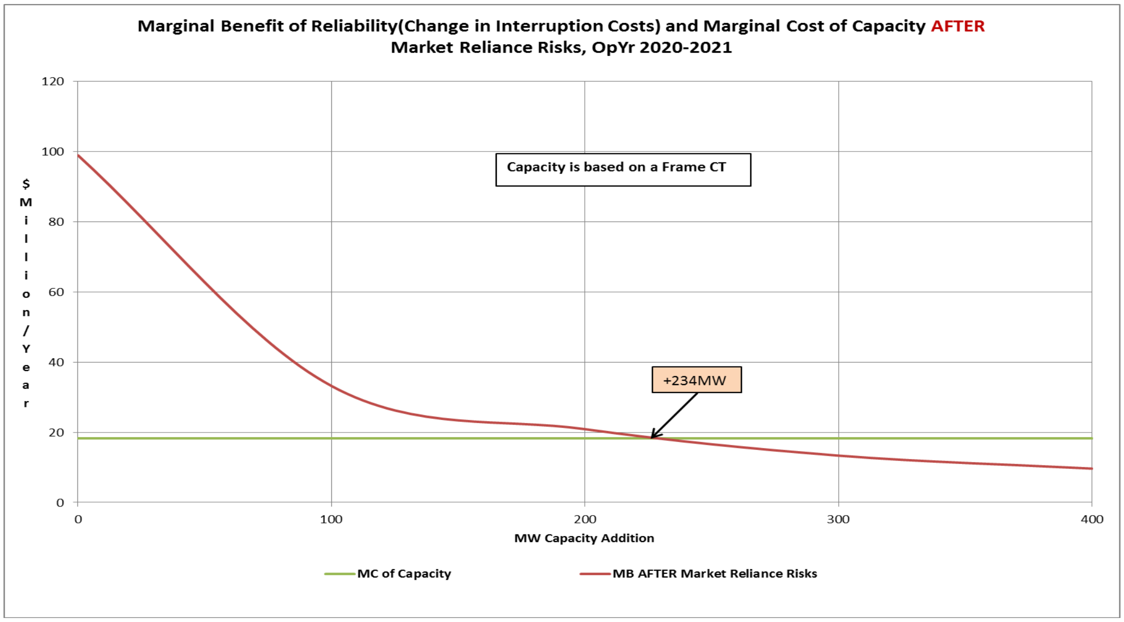
Figure 6-3: Benefit/Cost Comparison, 2015 Optimal Planning Standard Highlighted

Added CT Capacity (MW)	Cost of Reliability ($mill/yr)		Expected Benefit of Improving Reliability ($mill/yr)		B/C Test	Risk Benefit ($mill/yr)	
	Added Resource Cost	Incremental Cost	Expected VOLL	VOLL Reduction Incremental Benefit	Benefit/ cost Ratio	Reliability Risk TVar90 of VOLL	Reduction in VOLL risk
0	0		98			989	
100	18	18	64	33	1.8	641	348
234*	43	25	39	25	1.0	385	257
300	55	12	30	9	0.7	299	86

** 2015 Optimal Planning Standard*

Figure 6-4 illustrates where the marginal benefit and marginal cost of reliability to customers intersects using the 2015 Optimal Planning Standard. This chart shows that as generation increases, the incremental benefit created by that addition falls. This is because fewer and fewer outages are avoided by the increased generation. The incremental cost is constant (shown here as the incremental cost of adding 100 MW blocks of generation). The chart shows that if we stopped adding generation before 234 MW, we would be leaving value on the table for customers, because the benefits exceed costs up to that point. On the other hand, adding generation beyond 234 MW would cost customers more than it saves, reducing the net benefit to customers to below the $67 million per year.

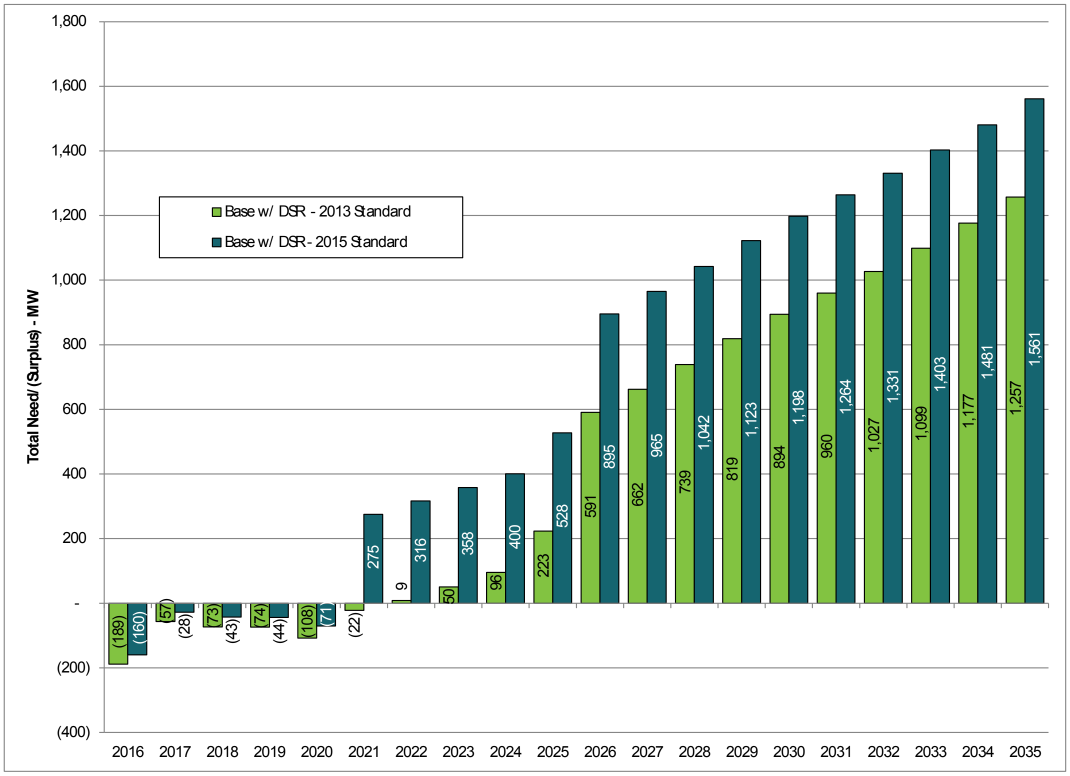
Figure 6-4: Marginal Benefit of Reliability, 2015 Optimal Planning Standard



Using this cost/benefit approach will enable us to continue to identify the optimal planning margin even as conditions in the region and PSE's service territory change over time.

Figure 6-5 compares the winter peak resource need under the 2013 Planning Standard to the winter peak need under the 2015 Optimal Planning Standard.

Figure 6-5: December Peak Capacity Need after Demand-side Resources, 2015 and 2013 Planning Standards



The benefit/cost analysis in Figures 6-3 and 6-4 show a capacity addition of 234 MW, while the peak capacity need chart in Figure 6-5 shows a 275 MW resource need in 2021 after DSM. There are three reasons these numbers are slightly different:

1. **Estimated Conservation vs Forecast Conservation**. The RAM analysis used to calculate the 234 MW capacity addition included conservation assumptions from the 2013 IRP, since 2015 IRP conservation savings cannot be determined until after the updated resource need has been established.
2. **Operating Reserves.** PSE's operating reserve obligations vary as a function of the estimated and forecasted 2021 conservation-related peak load reductions.
3. **Mid-C Wholesale Purchases.** The amounts of wholesale purchases that PSE can import from the Mid-C using its firm transmission rights is a function of the operating reserves being maintained at PSE's Mid-C hydro plants.

Incremental Capacity Equivalents (ICE). The incremental capacity credits assigned to PSE's existing and prospective resources were developed by applying the incremental capacity equivalent (ICE) approach[6] in the RAM. In essence, the ICE approach identifies the equivalent capacity of a gas-fired peaking plant that would yield the same customer optimal EUE level as the capacity of a different resource such as a wind farm, energy storage facility, Colstrip or wholesale market purchases using PSE's available firm Mid-C transmission import rights. The ratio of the equivalent gas peaker capacity to the alternative resource capacity is the incremental capacity equivalent (ICE); this value represents the capacity credit assigned to the alternative resource. For the 2015 IRP, ICE was calculated for existing and new wind projects, the Colstrip plant, and for wholesale market purchases.[7]

Assessing the Capacity Contribution of Wholesale Market Purchases. To include wholesale market reliability risk in the analysis, we applied ICE analysis to wholesale market purchases – the same approach we use to assess the peak capacity value of other variable energy resources like wind, solar and batteries. ICE analysis is an important part of PSE's Resource Adequacy Model (RAM) because it allows us to assess the capacity value of resources with very different characteristics. ICE is defined and calculated as the change in capacity of a generic natural gas peaking plant that results from adding to the system a different type of resource with any given set of energy production characteristics, while keeping the resource adequacy metric constant.

Before performing the ICE analysis, we had to do two things: 1) determine what planning standards would be used in the ICE analysis (as discussed earlier), and 2) identify the impact that the regional resource adequacy forecasts would have on PSE's system and customers.

TRANSLATING REGIONAL FORECASTS TO PSE IMPACTS

Determining the impact of regional deficit forecasts on PSE was accomplished as part of a study performed by Lloyd Reed of Reed Consulting for PSE. That study is reported in detail in Appendix G, Wholesale Market Risk. Most relevant to this discussion is that the study:

a. identified forecasted regional shortages, beginning with data from the NPCC and BPA's regional adequacy analyses,[8]
b. allocated those market shortages to PSE's portfolio, and
c. modeled this allocation against 7 potential resource configuration cases for the region.

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6 | The ICE approach is similar to the equivalent load carrying capability (ELCC) approach.
7 | Additional details regarding the ICE computations are contained in Appendix N.
8 | Refer to Appendix F, Regional Resource Adequacy Studies.

For the input to the ICE analyses, PSE chose the regional resource configuration it judged most likely to be in place at 2021. This configuration (Wholesale Market Reliance Scenario 7) made adjustments to the base assumptions about regional imports, resource additions and resource refinements used in the NPCC's May 2015 Resource Adequacy Advisory Committee analysis, as was discussed in the previous section.

ANALYSIS RESULTS

Once the 2015 Optimal Planning Standard and associated reliability metrics were established and we determined which regional resource configuration to model, we could perform the ICE analysis to assess the peak capacity value of wholesale market purchases.

Figure 6-6 summarizes the ICE analysis results for all capacity resources using both the 2013 Planning Standard and the 2015 Optimal Planning Standard.

Figure 6-6: Incremental Capacity Equivalent (ICE) Values/Capacity Credits for Winter 2020-2021

Incremental Capacity Equivalent for Winter 2020-2021		
Resource Type	**2013 Standard**	**2015 Standard**
Baseline: Natural Gas Peaker	**100%**	**100%**
1) Existing Wind (Cumulative = 822MW)	12%	9%
2) New Wind (SE Washington = 100MW)*	8%	8%
3) Batteries (4 hour discharge + min 4 hour recharge)	100%	100%
4) Colstrip	92%	90%
5) Available Mid-C Transmission (Wholesale Market Purchases)	100%	84%

**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 incremental capacity equivalents for other wind sites must account for the incremental transmission costs required to connect the site to the regional grid. (PSE examined the incremental capacity if a central Washington wind project in the 2011 IRP.)*

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.[9] Chapter 5 presents the 2015 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.

Planning Margin.[10] Planning margins represent the amount of resources needed to achieve a specific planning standard reliability target. As discussed earlier in this chapter, this analysis tested two planning standards. We performed significant amounts of portfolio analysis using each of the planning standards, because we were simultaneously analyzing resource needs and portfolio analysis. The planning standard made no difference in the mix of resources, only in the quantity of resources and the timing of their addition.

9 / 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.
10 / A detailed, technical explanation of how planning margins were calculated can be found in Appendix N, Electric Analysis.

The 2015 Optimal Planning Standard (shown in Figure 6-3 above) resulted in a 2021 planning margin of 20.0 percent, in part because incorporating wholesale market risk in the capacity value of short-term market purchases via ICE analysis reduced their peak capacity value by 269 MW. Using the 20.0 percent planning margin would have implicitly increased this 269 MW adjustment at the same rate as load growth, which would overstate resource need going forward. In order to avoid this, we pulled out the 269 MW and treated it separately. We adjusted the single 20.0 percent value to 13.7 percent plus a fixed 269 MW capacity adjustment to reflect the wholesale market purchase risk component. This two-stage adjusted planning margin yields the same 1,059 MW capacity margin value for 2021, as shown in Figure 6-7. We expect this planning margin to change as we regional resource adequacy assumptions are updated in the future and as changes to PSE's existing portfolio are made.

Figure 6-7: Calculation of PSE's 2021 Planning Margin

	Option A	Option B
Planning Margin (% of Normal Peak Load)	20%	13.7%
Wholesale Market Purchase Risk Adjustment	0 MW	269 MW
Total Capacity above Normal Peaker	1,059 MW	1,059 MW

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 balancing 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 new rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The new rule requires PSE to carry reserve amounts equal to 3 percent of on-line generating resources (hydro, wind and thermal) plus 3 percent of load to meet contingency obligations. The terms “load” and “generation” in the new rule refer to the total net load and all generation in PSE’s Balancing Authority (BA). This increases PSE’s reserve requirement, because the rule now requires PSE to carry reserves for third-party loads and generation in addition to our own. The previous rule applied higher percentages (5 percent of hydro and wind and 7 percent of thermal resources) but to a smaller set of generating resources – only those owned and operated by PSE.

BALANCING 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.[11]

For PSE, the amount of balancing reserves is 123 MW. This amount is based on a 95 percent confidence interval, or the amount of reserves that would capture 95 percent of the within-hour load and resource deviations. This confidence interval is derived from historical data during the months of December and January, to coincide with the period used for PSE’s winter-peak planning. A full description of how this number was calculated can be found in Appendix H, Operational Flexibility.

Existing Resources. In examining the peak capacity value of existing resources PSE performed two sets of ICE analysis, one for each of the planning standards being examined. As mentioned earlier, ICE enables us to assess the capacity value of resources with very different characteristics. This value changes depending upon the planning standard applied, since ICE is defined and calculated as the change in capacity of a generic natural gas peaking plant that results from adding to the system a different type of resource with any given set of energy production characteristics, *while keeping the resource adequacy metric constant*. (Existing resources are described in detail in Appendix D.)

11 / System flexibility needs are discussed in more detail in Appendix H, Operational Flexibility.

SUMMARY OF EXISTING RESOURCES ASSESSMENT

Figure 6-8 summarizes the winter peak capacity values for PSE's existing supply-side resources.

Figure 6-8: Existing Supply-side Resources
Nameplate Capacity and Winter Peak Capacity for December 2016

Type of Generation	Nameplate Capacity (MW)	Winter Peak Capacity (MW) 2015 Standard
Hydro	996	897
Colstrip	677	592
Natural Gas	1,888[1]	2,008
Wind	823[2]	74
Contracts	805[3]	765
Available Mid-C Transmission	2,331	1,686
Total Supply-side Resources	**7,520**	**6,022**

NOTES
1 The nameplate capacity for the natural gas units is based on the net maximum capacity that a unit can sustain over a 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 as a wind resource (50 MW)
3 Includes Centralia contract at 380 MW in December 2016

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, 645 MW, is allocated to long-term contracts and existing resources such as PSE's portion of the Mid-C hydro projects. This leaves 1,686 MW of capacity available for short-term market purchases. The specific allocation of that capacity as of December 2016 is listed below in Figure 6-9. 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 6-10, Electric Peak Capacity Need.

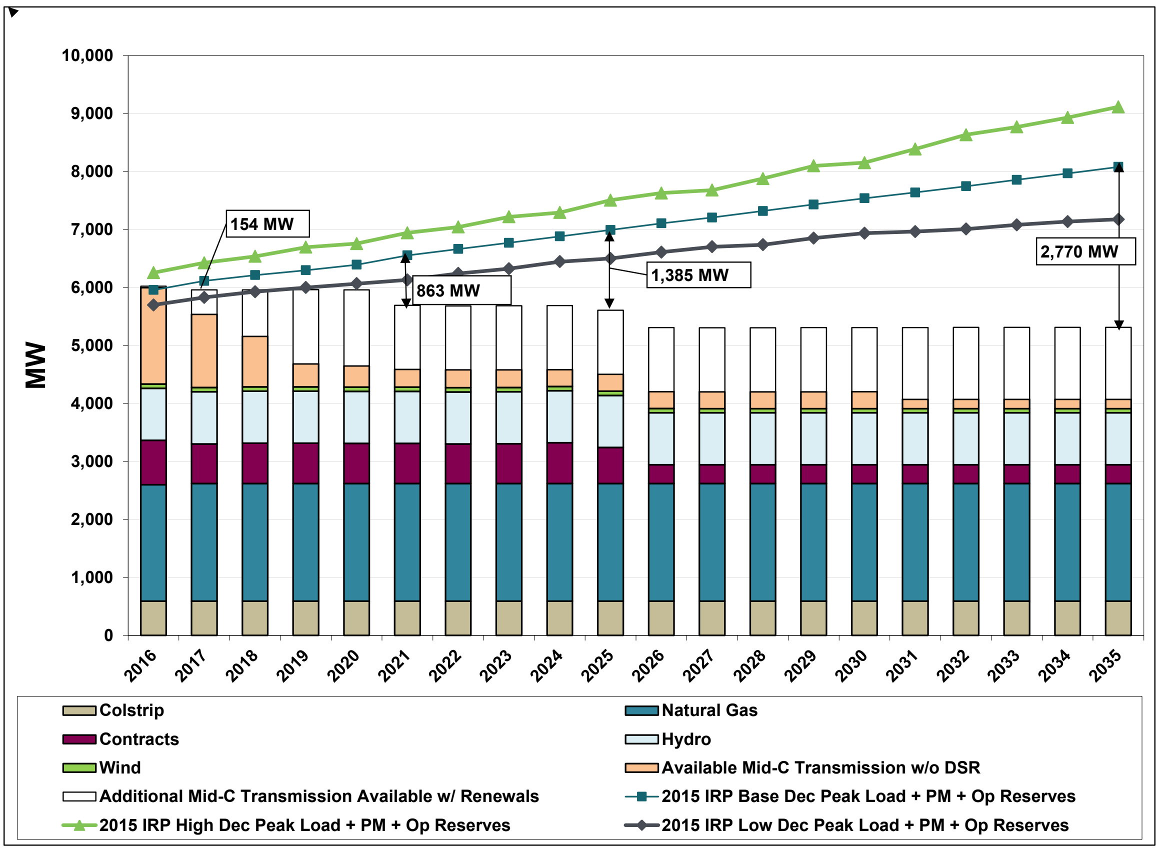
Figure 6-9: PSE Mid-C Transmission Capacity as of December 2016

	Winter Peak Capacity (MW)
Total Mid-C Transmission	2,331
Allocated to Long-term Resources & Contracts	(645)
Available for short-term wholesale market purchases	1,686

Peak Capacity Need

Figure 6-10 shows the physical reliability need for the three demand scenarios modeled in this IRP. This picture applies the optimal planning standard (2015), and it incorporates the ICE adjustment to wholesale market purchases discussed above. Before any additional demand-side resources, peak capacity need in the base case is almost 900 MW by 2021 and over 2,700 MW by the end of the planning period. This picture differs from Figure 6-5 above, 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 6-10: Electric Peak Capacity Need**
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



* *See note next page.*

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 (RAM). 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.

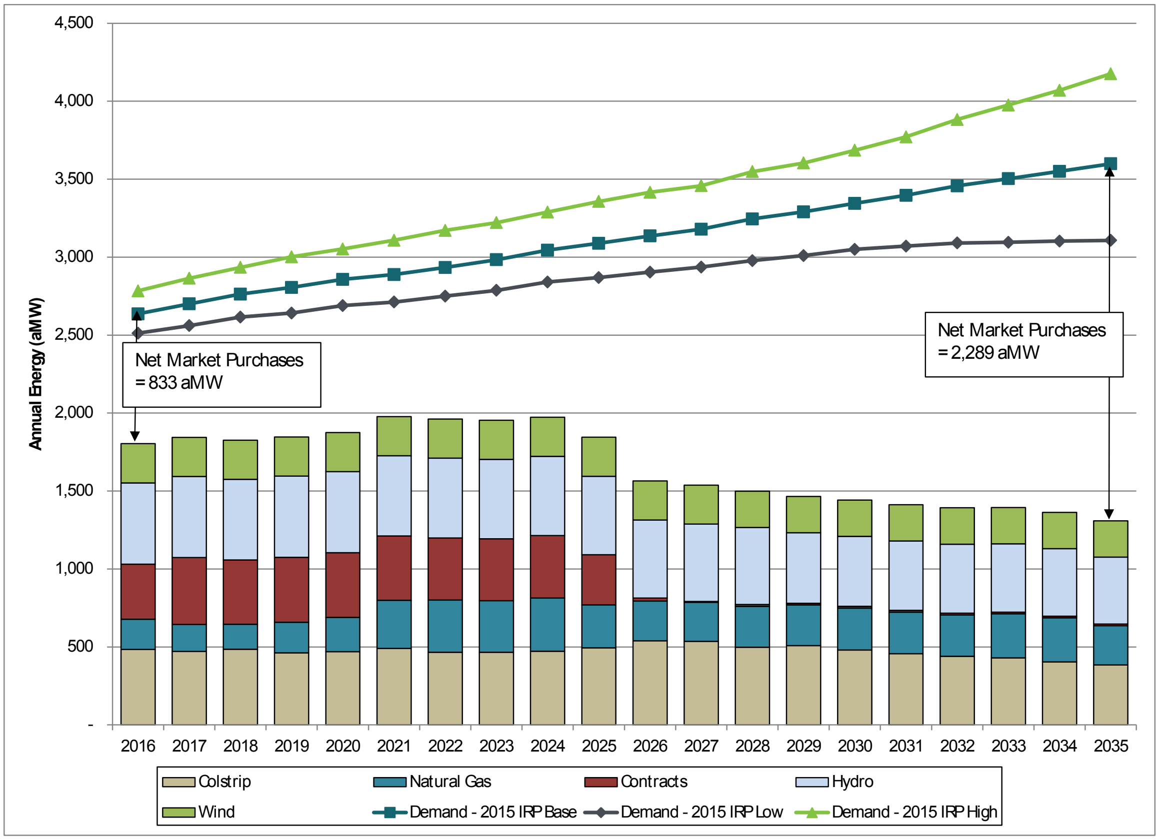
Energy Need

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 6-11 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2015 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions.

Figure 6-11: 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 through 2022, including the ability to bank RECs. For all practical purposes, wind remains the main resource available to fulfill RPS requirements for PSE. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river and efficiency upgrades, and other renewable technologies are not yet capable of producing power on a large enough scale to make substantial contributions to meeting the targets.

EMERGING RESOURCES STUDIES

PSE continues to monitor emerging resources that may develop effective utility applications. This IRP tests portfolio sensitivities that incorporate renewable resources such as battery storage and distributed solar generation. The results of these sensitivity analyses are discussed later in this chapter and in more detail in Appendix L, Electric Energy Storage, and Appendix M, Distributed Solar.

RENEWABLE RESOURCES INFLUENCE SUPPLY-SIDE RESOURCE DECISIONS

Adding wind 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 wind drops off when the wind stops, but customer need does not, therefore, as the amount of wind in the portfolio increases, so does the need for reliable backup generation.

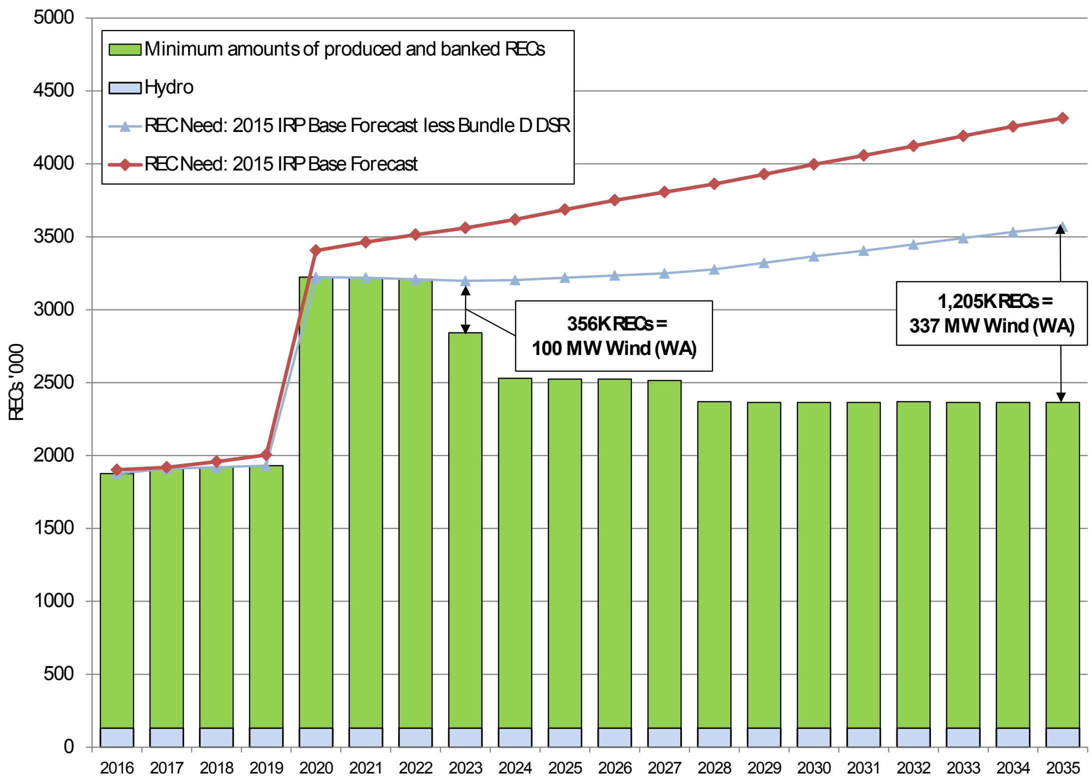
DEMAND-SIDE ACHIEVEMENTS AFFECT RENEWABLE AMOUNTS

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 6-12 illustrates the need for renewable energy – namely wind – after accounting for REC banking and the savings from demand-side resources that were found cost effective for the 2015 IRP.

Figure 6-12: REC Need Based on Achievement of All Cost-effective DSR



ASSUMPTIONS AND ALTERNATIVES

The scenarios, sensitivities and resource alternatives used in the electric analysis are summarized here for convenience.[12]

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 variable. They allow us to isolate the effect of an individual variable on the portfolio, so that we can consider how different combinations of resources would affect costs, cost risks and emissions.

Figure 6-13: 2015 IRP Scenarios

	Scenario Name	Gas Price	CO_2 Price	Demand
1	Low Scenario	Low	None	Low
2	Base Scenario	Mid	Mid	Mid
3	High Scenario	High	High	High
4	Base + Low Gas Price	Low	Mid	Mid
5	Base + High Gas Price	High	Mid	Mid
6	Base + Very High Gas Price	Very High	Mid	Mid
7	Base + No CO_2	Mid	None	Mid
8	Base + High CO_2	Mid	High	Mid
9	Base + Low Demand	Mid	Mid	Low
10	Base + High Demand	Mid	Mid	High

12 / 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 (CO2) 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.

Fig 6-14: 2015 IRP Portfolio Sensitivities

	Sensitivities	Alternatives Analyzed
	Electric Analysis	
A	Colstrip If Colstrip units are retired, what's the most cost-effective way to replace those resources?	*Baseline – All 4 Colstrip units remain in service* 1. Retire Units 1 & 2 in 2026. 2. Retire all 4 units in 2026.
B	Demand-side Resources (DSR) How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements* 1. No DSR. All needs are met with supply-side resources.
C	Thermal Mix How does changing the mix of resources affect portfolio cost and risk?	*Baseline – All peakers selected as lowest cost in the Base Scenario deterministic portfolio.* 1. All CCCT 2. Mix CCCT and frame peaker
D	Gas Plant Location What if the gas plants were built in eastern Washington instead of PSE service territory?	*Baseline – Gas plants located in PSE Service territory* 1. Model gas plants with gas transport costs and transmission costs from eastern Washington.
E	Gas Transport/Oil Backup for Peakers What if peakers cannot rely on oil for backup fuel and must have firm gas supply instead?	*Baseline – 50% firm pipeline capacity with 48 hours of oil backup* 1. 100% firm pipeline capacity with no oil backup
F	Energy Storage/Flexibility What is the cost difference between a portfolio with and without energy storage? How do energy storage resources impact system flexibility?	*Baseline – Batteries and pumped hydro included only when chosen economically* 1. Add 80 MW battery in 2023 instead of economically chosen peaker. 2. Add 80 MW pumped hydro storage in 2023 instead of economically chosen peaker. 3. Add 200 MW of pumped hydro storage in 2023 instead of economically chosen peaker.
G	Reciprocating Engine/Flexibility How do reciprocating peakers affect system flexibility?	*Baseline – Reciprocating peakers modeled at 220 MW with an all-in cost of $1,599 per kW* 1. Model lower capital cost for 75 MW recip peaker. 2. Add 75 MW recip peaker with lower capital cost in 2023. 3. Add 75 MW recip peaker with lower capital cost and flexibility credit in 2023.
H	Montana Wind Update transmission cost for Montana wind to be more optimistic if Colstrip continues to operate. Will MT wind be chosen in lowest cost portfolio?	*Baseline – PSE cost estimate for transmission upgrades to Montana* 1. Lower transmission cost estimate
I	Solar Penetration What if customers install significantly more rooftop solar than expected?	*Baseline – Rooftop solar growth based on current growth forecast trend* 1. Maximum potential capture of rooftop solar
J	Carbon Reduction How does increasing renewable resources and DSR beyond requirements affect carbon reduction and portfolio costs?	*Baseline – Renewable resources and DSR per RCW 19.285 requirements* 1. Add 300 MW of wind beyond renewable requirements. 2. Add 300 MW of utility-scale solar beyond renewable requirements. 3. Increase DSR beyond requirements.

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.

Combined-cycle Combustion Turbines (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.

Simple-cycle Combustion Turbines (Frame Peakers). F-type, wet-cooled turbines are assumed to generate 228 MW and located in PSE's service territory. Those modeled without 48 hours of oil backup were required to have firm gas pipeline capacity to cover 12 hours of operation and gas storage.

Aeroderivative Combustion Turbines (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. Those modeled without 48 hours of oil backup were required to have firm gas pipeline capacity to cover 12 hours of operation and gas storage.

Reciprocating Engines (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.

Wind. Wind was modeled in southeast Washington and central Montana. Washington wind is assumed to have a capacity factor of 34 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 41 percent.

Energy Storage. Two energy storage technologies are modeled: batteries and pumped hydro. The generic battery resource is lithium-ion technology. 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.

Solar. Utility-scale solar PV is assumed to be located in central to southern Washington, use a fixed tilt system, and have a capacity factor of 20 percent.

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 the same 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 that originate from federal and state codes/standards.

TWO TYPES OF ANALYSIS

PSE uses two types of analysis to develop its resource plan: deterministic optimization analysis and stochastic risk analysis.[13]

DETERMINISTIC PORTFOLIO OPTIMIZATION ANALYSIS

All scenarios and sensitivities are subjected to deterministic portfolio analysis. This is the first stage of the resource plan analysis. It identifies least-cost portfolio – that is, the 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.

CANDIDATE RESOURCE STRATEGIES

Using what we learned from the deterministic analysis, we created a set of candidate resource strategies to test different resource strategies. For example, how does the addition of a mix of thermal resources perform compared to the addition of a single type of thermal resource?

STOCHASTIC RISK ANALYSIS

In this stage of the resource plan analysis, we examine how the candidate 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 candidate resource strategies again. This allows us to learn how the candidate resource 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.

13 / 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.

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.

Three analytical tools are used during this stage of the analysis: Aurora, 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.

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: i) the variable fuel cost and emissions for PSE's existing fleet, ii) the variable cost of fuel emissions and operations and maintenance for new resources, iii) the fixed depreciation and capital cost of investments in new resources, iv) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and v) the market purchases or sales in hours when resource-dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM 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.

Candidate Resource Strategies

Candidate resource strategies were originally created in the portfolio model. The parameters of the model were relaxed to allow the resources to be 100 MW short of need, and the integer constraint was removed to allow fractions of plants to be added. DSR bundle D was chosen in the majority of the portfolios in the deterministic portfolio analysis, so all the candidate resource strategies include DSR bundle D, the codes and standards bundle, distribution efficiency, distributed solar PV, and demand-response programs 1 and 5. Also, based on the results of the deterministic portfolio analysis, wind is added to meet the RPS, so wind was sized exactly to meet the RPS for the 2015 IRP Base load forecast. After the wind and DSR were added to the candidate resource strategies, thermal plants were added to meet capacity need. Six candidate resource strategies were created using the Base Scenario. The first option, all frame peakers, is the lowest cost portfolio in the deterministic analysis of the Base Scenario.

The six candidate resource strategies tested were:

1. All frame peakers.
2. Early recip peaker added in 2021 and the remainder of the thermal units are frame peakers.
3. Early CCCT added in 2021 and then the remainder is a mix of CCCT, frame peaker and recip peaker.
4. All CCCT.
5. Mix CCCT and frame peaker. This portfolio has a frame in 2021 and 2025 and a CCCT in 2026.
6. Additional 300 MW of wind in 2021.

Stochastic Risk Analysis

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

For this purpose, we take the portfolio candidates (drawn from a subset of the lowest cost portfolios produced in the deterministic analysis) and run them through 250 draws[14] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed. For example, in the deterministic analysis for this IRP, the frame peaker was lowest cost resource addition in the Base Scenario portfolio, but many other scenarios included the CCCT in the lowest cost portfolio. When we perform the stochastic analysis, we find that the CCCT reduces the portfolio's risk, because it provides a benefit to the portfolio in many of the draws; by running the stochastic analysis, we learn that balancing the portfolio with both peakers and CCCT plants is the better option. The goal of the process is to find the set of resources with the lowest cost and the lowest risk.

ANALYSIS TOOLS

A Monte Carlo approach is used to develop the stochastic inputs. Monte Carlo 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.

14 / Each of the 250 simulations is for the twenty-year IRP forecasting period, 2016 through 2035.

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.

Incorporating wholesale market risk into the planning standard and resource capacity values was such a complex and lengthy process that it was necessary to begin the IRP analysis before that process was finished. That is why some analyses were performed using the 2013 Planning Standard. Where the results were sensitive to the change, we performed the analysis again using the 2015 Optimal Planning Standard.

Scenarios

1. **Portfolio Builds.** Portfolio additions across scenarios are very similar. The most common difference was which type of gas-fired generation was selected, peakers or CCCT plants.
    a. 2013 Planning Standard
    b. 2015 Optimal Planning Standard
2. **Emissions.** Emissions results vary across portfolios, with the economic dispatch of coal generation as the primary factor that differentiates results.
    a. 2013 Planning Standard
    b. 2015 Optimal Planning Standard
3. **Cost of Peakers vs. CCCT Plants.** Market conditions affect the net cost of peakers vs. CCCT plants, not the resource needs.
4. **Renewables.** RPS requirements and load forecasts drive renewable builds.
5. **Wind vs. Solar.** Wind remains more cost-effective than utility-scale solar.

Sensitivities (using 2013 Planning Standard)

A. **Colstrip.** If Colstrip units 1 & 2 had to be replaced in 2026, resource additions would be consistent across the Low, Base and High scenarios. That is, Colstrip being in or out of the portfolio does not impact the mix of resource additions. If all four units were out of operation, new combined-cycle plants would be part of the least-cost mix, since market heat rates would be impacted enough to drive down the net cost of CCCT making it cost effective.

B. **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.

C. **Thermal Mix:** A mix of gas-fired thermal resources reduces expected cost and reduces risk, relative to selecting only one type of gas-fired thermal plant.

D. **Gas Plant Location:** The location of resources (east vs. west of the Cascades) is a very close call. Qualitative considerations of BPA transmission policy risk and sub-hourly value being connected to our BA tips the balance in favor of resources on our system for the IRP.

E. **Gas Transport/Oil Backup for Peakers:** Non-firm pipeline capacity may be significantly limited for extended winter periods in the future. For the near future, existing dual-fuel units do not appear to require firm pipeline capacity – current oil tanks can supply sufficient backup fuel. Further out in the planning horizon, however, it is not clear whether enough oil storage could be permitted to avoid the need for additional firm pipeline capacity and ensure peakers can run during on-peak hours.

F. **Energy Storage and Flexibility:** Batteries and pumped hydro storage are higher cost than traditional peaking plants, although energy storage can provide valuable flexibility. Even including this value, however, battery technology needs to come down in price before they will look cost effective as an energy supply resource. At present, the flexibility value of batteries would have to be 50 percent greater than our current estimates for batteries to be cost effective. We will continue to improve our analytical capabilities with respect to flexibility and energy storage.

G. **Flexibility and Reciprocating Engines:** Adjusting the relative cost of CCCTs, CTs, reciprocating engines and batteries for our initial estimates of flexibility value changed the optimal mix of resource additions. Reciprocating engines became the dominant new resource – though there may be challenges with air permits, given updated EPA standards on particulate emissions.

H. **Montana Wind:** Based on current assumptions, Montana wind is not expected to be cost effective because of transmission cost. Even in the sensitivity where Colstrip was retired and wind from Montana could rely on the existing transmission system at embedded cost rates, the capacity contribution of the wind would have to be greater than 50 percent to be cost effective – which is clearly a very high hurdle. We will study additional hourly wind data from Montana wind projects in the next IRP, if we can acquire the data.

I. **Solar Penetration:** Assuming customers own their own distributed solar generation systems (typically rooftop solar panels), the primary energy-supply-related impact of high solar penetration would be to reduce the need for RPS compliant resource additions since load would be lower. Otherwise the resource mix is not affected. High penetration of distributed solar in PSE's service territory may create different kinds of engineering challenges to solve on different kinds circuits. In the future, distributed solar could create synergies between energy supply planning and distribution system planning, if energy storage or other energy supply resources are a cost effective part of the solution to those challenges on the distribution system.

J. **Carbon Abatement:** DSR and wind resources affect emission rates, but to a much smaller extent than Colstrip or the Coal Transition PPA.

Candidate Resource Strategies

(using 2015 Optimal Planning Standard)

Deterministic analysis was used to develop several candidate resource strategies to test in the stochastic portfolio risk analysis. Combinations of resources were tested based on deterministic results, to test individual thermal resources, such as an all CCCT portfolio, a mix of thermal resources, and additional wind.

1. **All Frame Peakers.** This portfolio is the lowest cost in the Base Scenario, but in the stochastic analysis, it had higher average cost and risk than the portfolios with CCCT.
2. **Early Recip Peaker.** This portfolio had a higher expected cost and risk than the all-frame-peaker portfolio.
3. **Early CCCT with Thermal Mix.** This portfolio had a higher expected cost because of the Recip Peakers, but the risk was lower than the all frame peaker portfolio because of the CCCT plants.
4. **All CCCT.** This portfolio has the highest cost in the expected base scenario, but the lowest average cost and risk in the stochastic simulations.
5. **Mix CCCT and Frame Peaker.** This portfolio has a higher cost in the expected base scenario than the all frame peaker, but has a lower average cost and risk in the stochastic simulations.
6. **Additional 300 MW of Wind.** This portfolio is higher cost and higher risk than the all frame peaker portfolio.

SCENARIO ANALYSIS RESULTS

1. 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. CCCTs were selected as lower cost in some scenarios, while frame peakers were selected as lower cost in others. Also, in the High Scenario, wind was cheaper than market due to such high gas and carbon prices, so in this scenario, it was necessary to constrain wind to 1,000 MW. If wind 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 wind 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 6-15 summarizes resource additions and net present value of portfolio costs across the 10 scenarios.

Figure 6-15: Relative Optimal Portfolio Builds and Costs by Scenario by 2035, 2013 Planning Standard

(Energy in total MW. Dollars in billions. NPV includes end effects.)

		NPV	DR	DSR	CCCT	Peaker	Wind	Biomass	Battery
1	Low	$7.20	174	888	-	455	200	-	-
2	Base	$12.28	172	906	-	1,138	300	15	80
3	High	$17.59	174	906	2,312	-	1,000	-	-
4	Base + Low Gas Price	$11.57	172	906	771	455	300	15	-
5	Base + High Gas Price	$12.90	172	906	-	1,138	300	15	80
6	Base + Very High Gas PrIce	$13.66	172	968	-	1,138	600	-	-
7	Base + No CO2	$9.92	172	906	771	455	300	15	-
8	Base + High CO2	$13.50	172	956	1,156	-	400	-	-
9	Base + Low Demand	$9.76	174	888	-	455	200	-	-
10	Base + High Demand	$15.55	254	956	1,542	683	500	-	-

The portfolio builds for all scenarios look similar to the portfolio builds for the 2013 planning standard with the exception of more resources added to meet the higher need.

Figure 6-16: Relative Optimal Portfolio Builds and Costs by Scenario by 2035,
2015 Optimal Planning Standard
(Energy in total MW. Dollars in billions. NPV includes end effects.)

		NPV	DR	DSR	CCCT	Peaker	Wind	Biomass/ Solar*	Battery
1	Low	$7.67	230	888	-	683	200	-	-
2	Base	$12.79	148	906	385	1,138	300	15	-
3	High	$17.99	230	906	2,312	228	1,000	-	-
4	Base + Low Gas Price	$12.04	148	906	385	1,138	300	15	-
5	Base + High Gas Price	$13.41	148	906	-	1,593	300	15	-
6	Base + Very High Gas Price	$14.18	148	968	-	1,366	500	-	80
7	Base + No CO2	$10.38	148	906	1,542	-	300	15	-
8	Base + High CO2	$13.95	148	906	1,542	-	400	-	-
9	Base + Low Demand	$10.20	148	906	-	683	200	-	80
10	Base + High Demand	$16.09	148	888	1,542	1,138	500	20	-

** 20 MW refers to a solar addition, and 15 MW is a biomass addition.*

Summary of Deterministic Optimization Analysis. Figure 6-17 below displays the megawatt additions for the deterministic analysis optimal portfolios for all scenarios in 2021, 2026 and 2035 using the 2013 Planning Standard. Under the 2013 standard, no new resources are added until 2023 except in the High and Base + High Demand scenarios; both use the high demand forecast.

Figure 6-18 is the same chart for the portfolios using the 2015 Optimal Planning Standard. Under the 2015 standard, new resources are added in 2021 to meet needs except in the Low and Base + Low Demand scenarios. See Appendix N, Electric Analysis, for more detailed information.

Figure 6-17: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW), 2013 Planning Standard

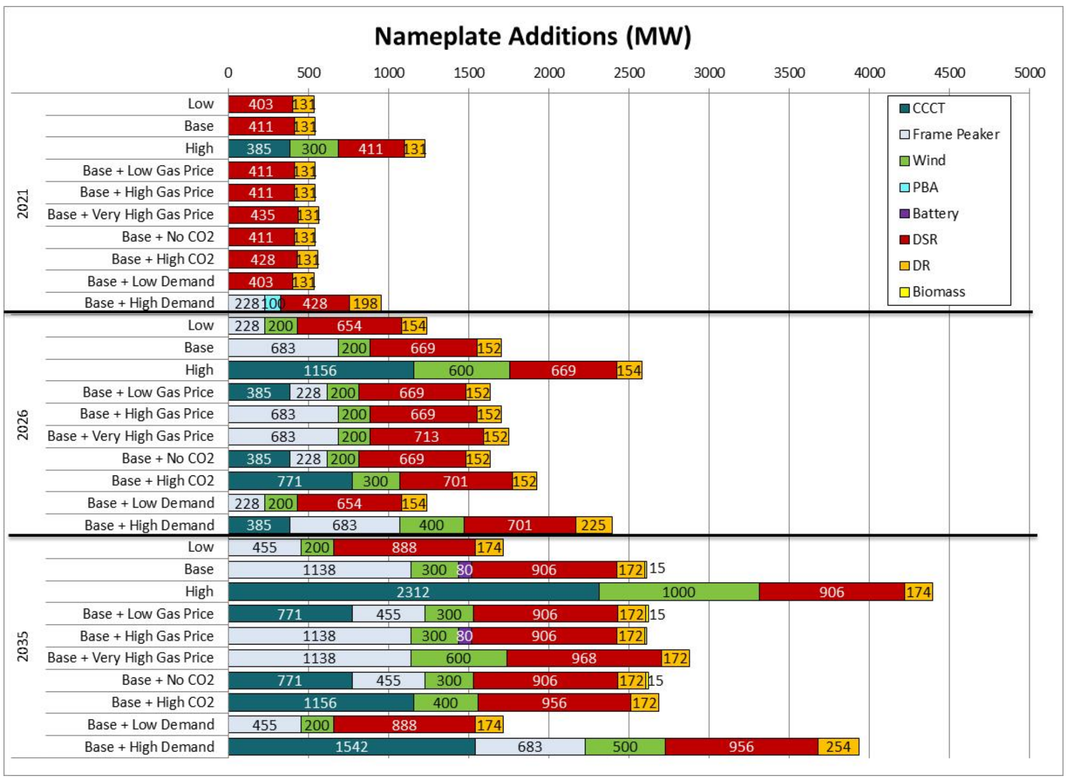
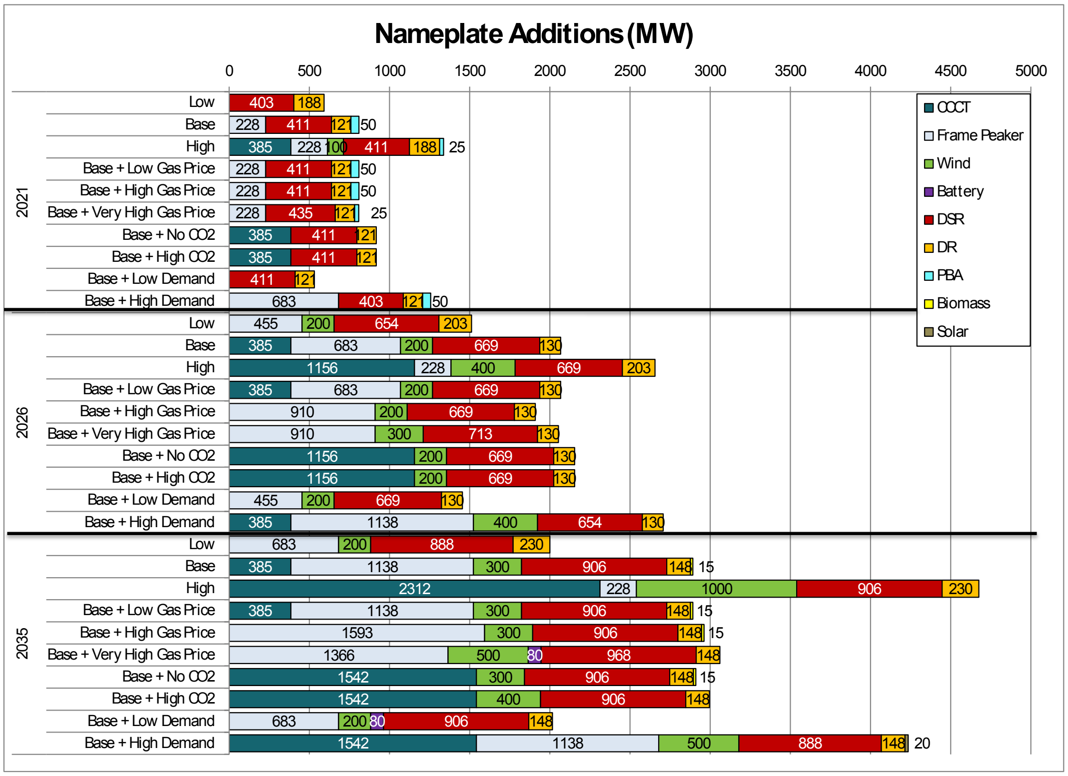


Figure 6-18: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW), 2015 Optimal Planning Standard



2. Emissions

PSE examined how different carbon mitigation strategies affect portfolio builds, costs and emissions. Figure 6-19 shows CO_2 emissions for the least-cost portfolio in each scenario using the 2013 Planning Standard; Figure 6-20 shows CO_2 emissions using the 2015 Optimal Planning Standard. Many of the portfolios show a drop in emissions in 2026 corresponding to the expiration of the Coal Transition PPA on December 31, 2025. As the charts illustrate, only four portfolios/scenarios reduce emissions below 1990 levels. In two of those scenarios, High and Base + High CO_2, the CO_2 price is high enough to reduce the dispatch of Colstrip.

Figure 6-19: CO_2 Emissions by Portfolio – 2013 Planning Standard

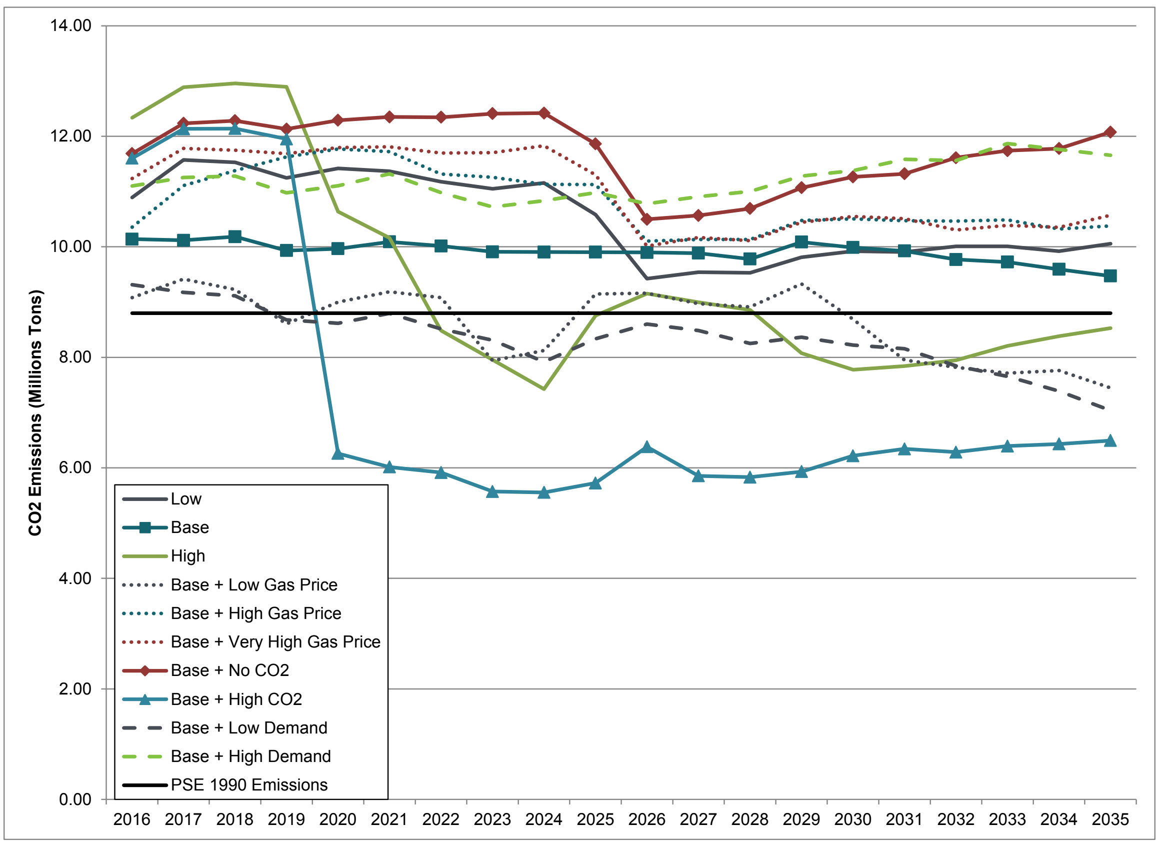
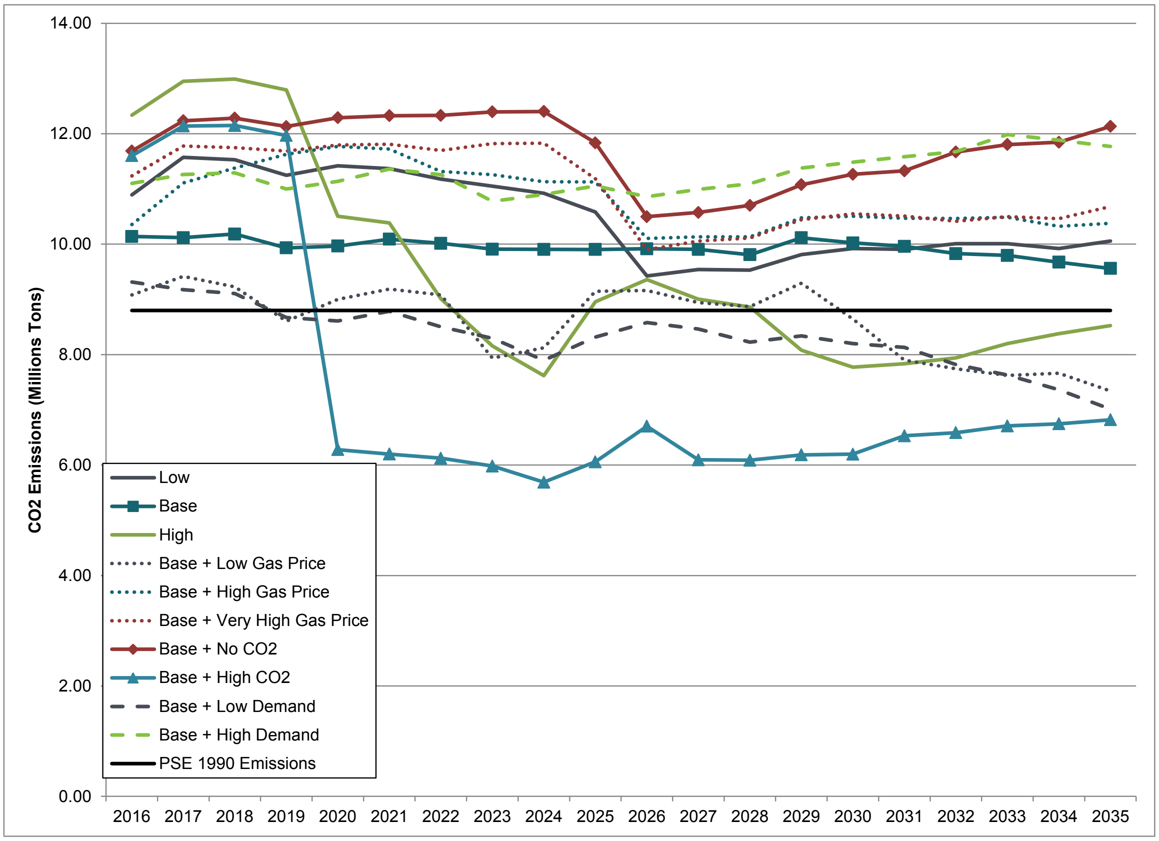
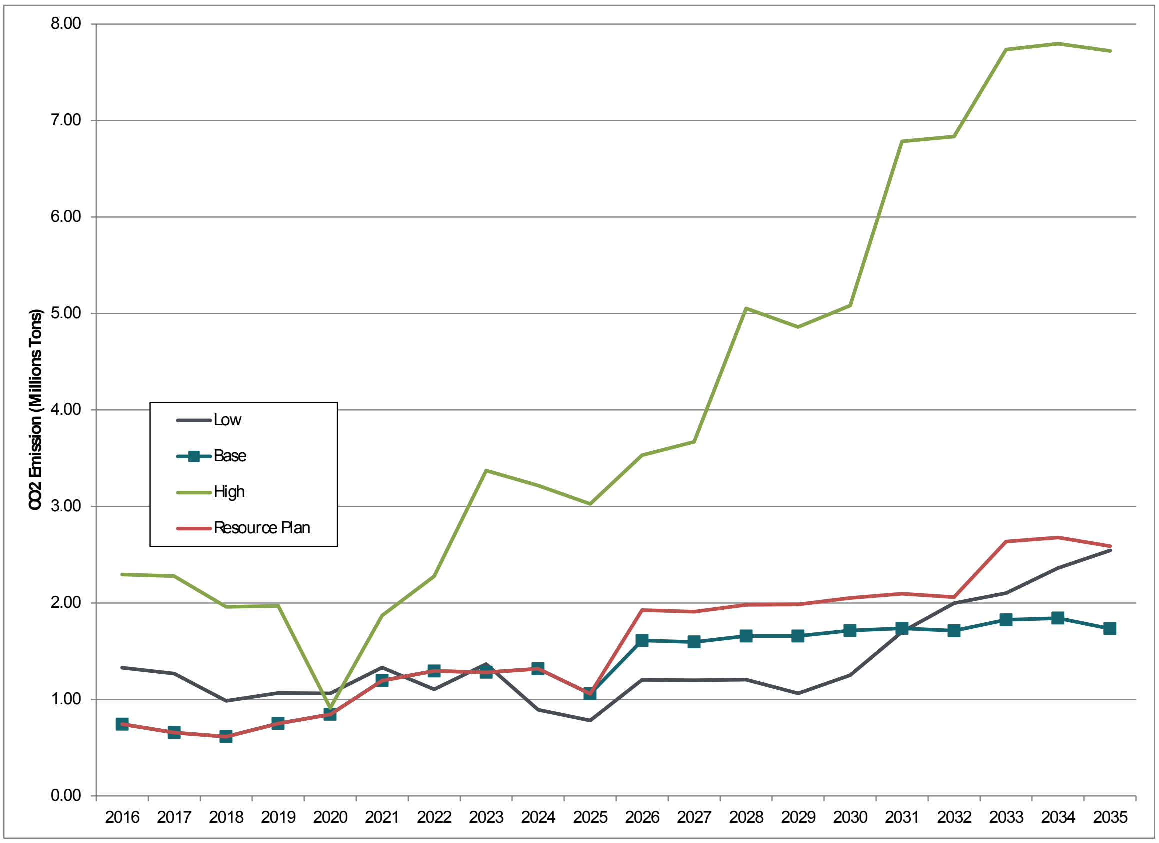


Figure 6-20: Projected CO_2 Emissions by Portfolio – 2015 Optimal Planning Standard



A portfolio view of carbon emissions does not reflect emissions occurring specifically in Washington state. Figure 6-21, below, shows a range of emissions from PSE's owned power plants that are located in Washington state, for the Base, High, and Low Scenarios. The chart illustrates that PSE's emissions in Washington are driven by dispatch of CCCTs. In the Base scenario, there is only one additional CCCT plant, but in the other two, all new additions are CCCT plants. A final line, showing the resource plan, is in the middle because it is a combination of CCCT and CT plants.

Figure 6-21: PSE's Projected Washington CO_2 Emissions – 2015 Optimal Planning Standard



3. Cost of Peakers vs. CCCT Plants

Peakers and CCCTs traded off being the lower cost resource, depending on the scenario. Figure 6-22 compares the cost of peakers and combined-cycle plants across 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 and without oil backup. For peakers with oil backup, we included 50 percent firm pipeline transportation costs, plus the cost of 48 hours of oil. Those without oil backup were assigned higher-priced firm fuel transportation and storage costs similar to those that CCCTs are burdened with.
- Plants are assumed to be located on the west side of the Cascades. (How location affects resource costs is discussed in sensitivity results.)
- The levelized cost for both the frame peaker and CCCT plant was calculated over the 35-year life of the plant from 2020-2054.

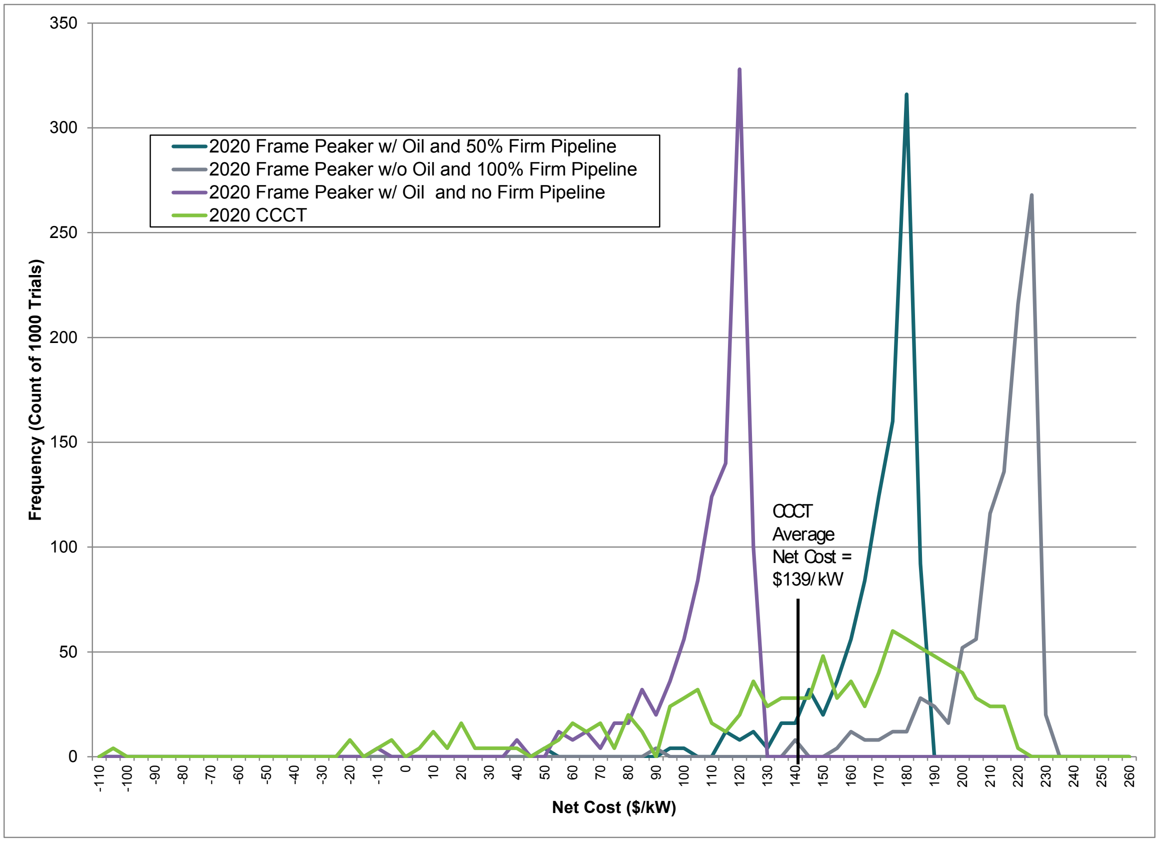
In the scenarios where the CCCT looks more cost effective, the dispatch of the CCCT plants is high, so the plant produces a lot of excess power to sell into the market; this creates revenue that lowers the net cost of the plant to customers, resulting in CCCTs being chosen in the lowest cost portfolio. The frame peaker costs are constant across all scenarios since there is no dispatch of the plant, so there are no variable O&M costs and no revenue on the plants, and the fixed costs remain constant across all scenarios. An exception is the Low Scenario, where there is a very small dispatch.

Figure 6-22: Peaker and CCCT Net Costs Compared

	Levelized Net Cost (2016 $/kW)	2020 Frame peaker: w/ oil and no firm pipeline	2020 Frame peaker: w/ oil and 50% Firm pipeline	2020 Frame peaker: w/o oil and 100% Firm pipeline	2020 CCCT
1	Low	$115.94	$166.23	$193.96	$184.10
2	Base	$115.97	$165.34	$193.99	$183.15
3	High	$115.97	$165.34	$193.99	$149.04
4	Base + Low Gas Price	$115.97	$165.34	$193.99	$170.09
5	Base + High Gas Price	$115.97	$165.34	$193.99	$184.00
6	Base + Very High Gas Price	$115.97	$165.34	$193.99	$186.15
7	Base + No CO2	$115.97	$165.34	$193.99	$159.90
8	Base + High CO2	$115.97	$165.34	$193.99	$155.04
9	Base + Low Demand	$115.97	$165.34	$193.99	$194.23
10	Base + High Demand	$115.97	$165.34	$193.99	$169.90

Figure 6-22 illustrates how the net cost of a CCCT plant is significantly affected by the margin it generates. A 250-simulation Monte Carlo analysis for a 2020 vintage plant shows how the net cost per kW of peakers and CCCT plants are distributed under different market conditions. The peakers show a very tight probability distribution of cost, because they do not dispatch or create much margin in many draws. In contrast, the CCCT plant margins are widely dispersed; this spreads out the CCCT probability distribution more broadly than the peaker distribution. Net cost is not specifically used as part of the cost minimization function; however, showing net cost may provide useful insights. Figure 6-23 illustrates that if sufficient backup fuel can be permitted and constructed so as to avoid needing any firm pipeline capacity, peakers with oil backup may be lower cost and lower risk than CCCT plants. The ability to permit sufficient backup fuel is a resource-specific-level decision, but it is difficult to believe the company could permit such resources in the future, as the natural gas system becomes more constrained and emissions regulations continue to get more stringent.

Figure 6-23: Comparison of Net Cost Distribution in the Base Scenario, CCCT and Peakers with Oil Backup (in 2016 dollars per kW)



4. Renewable Builds

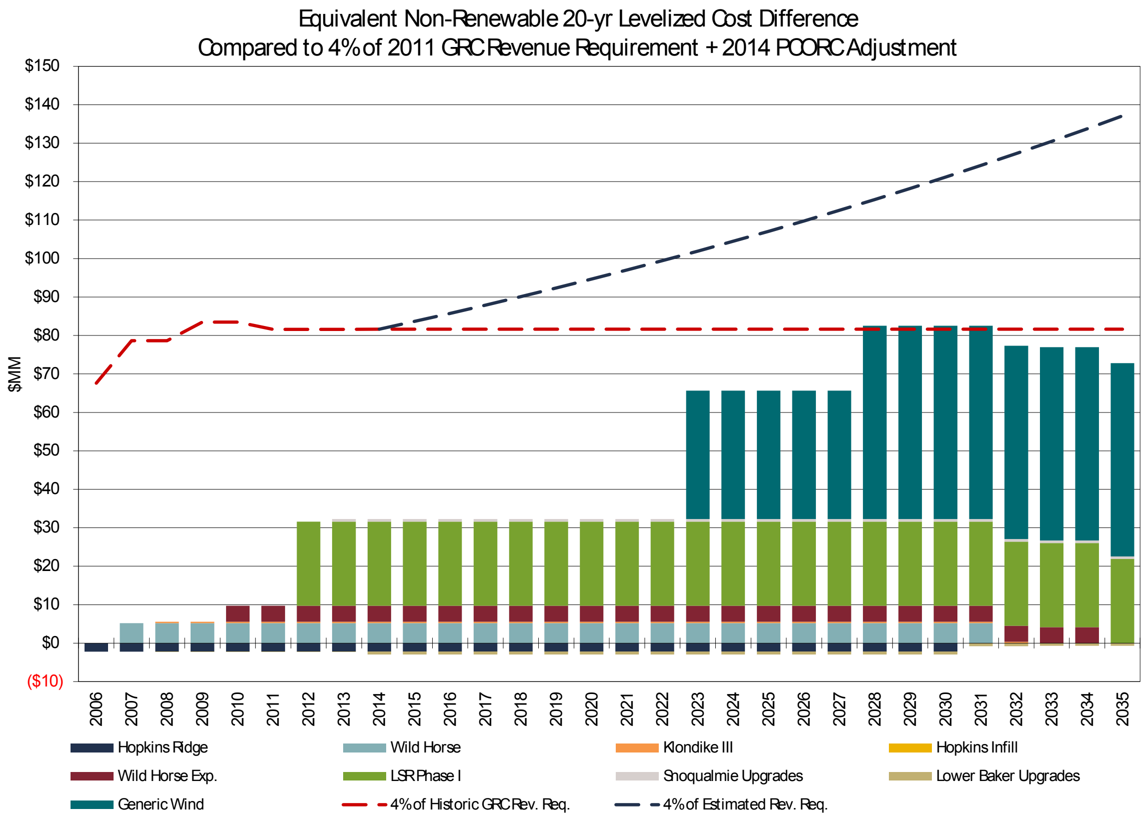
The amount of renewable resources included in portfolios is driven by RPS requirements. In all scenarios but High and Base + Very High Gas Price, wind resources are only added to meet the minimum requirements of RCW 19.285, not because they are least cost. See Figure 6-19 and 6-20 above for total wind 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.[15]

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 6-24 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.

15 / 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 6-24: Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4% of 2011 GRC Revenue Requirement + 2014 PCORC adjustment



5. Wind vs. Solar

The Puget Sound Region is on the lower end of solar potential in the United States,[16] and Washington state currently generates less than 1 MW of utility solar. PSE's Wild Horse solar facility (0.5 MW) has historically experienced an 18 percent capacity factor. Capacity factor has a significant impact on the economics of solar projects. Solar projects would provide no contribution to PSE's winter peak capacity since those peaks occur when it's dark and cold during the winter months. Even if solar could be imported from areas with higher solar potential, it would still make only limited contribution to peak capacity.

Photovoltaic technology costs have declined over the last decade, but there is uncertainty about the degree and pace of future price declines. Figure 6-25 shows the price curve, and the gray bar indicates the range of costs. The U.S. Energy Information Administration's 2014 Energy Outlook estimated the all-in capital cost for utility solar at $3,564 per kW (in 2012 dollars) or $4,000 per kW (in 2016 dollars). The levelized costs range from $101 to $200 per MWh with capacity factors ranging from 22 to 32 percent. Solar in the Puget Sound Region would fall into the upper end of the cost per MWh range or even higher due to the poor solar profile of the area.

16 / *A map that shows solar potential across the entire United States is included in Appendix M, Distributed Solar.*

Figure 6-25: Utility-scale Solar PV Capital Cost Estimates

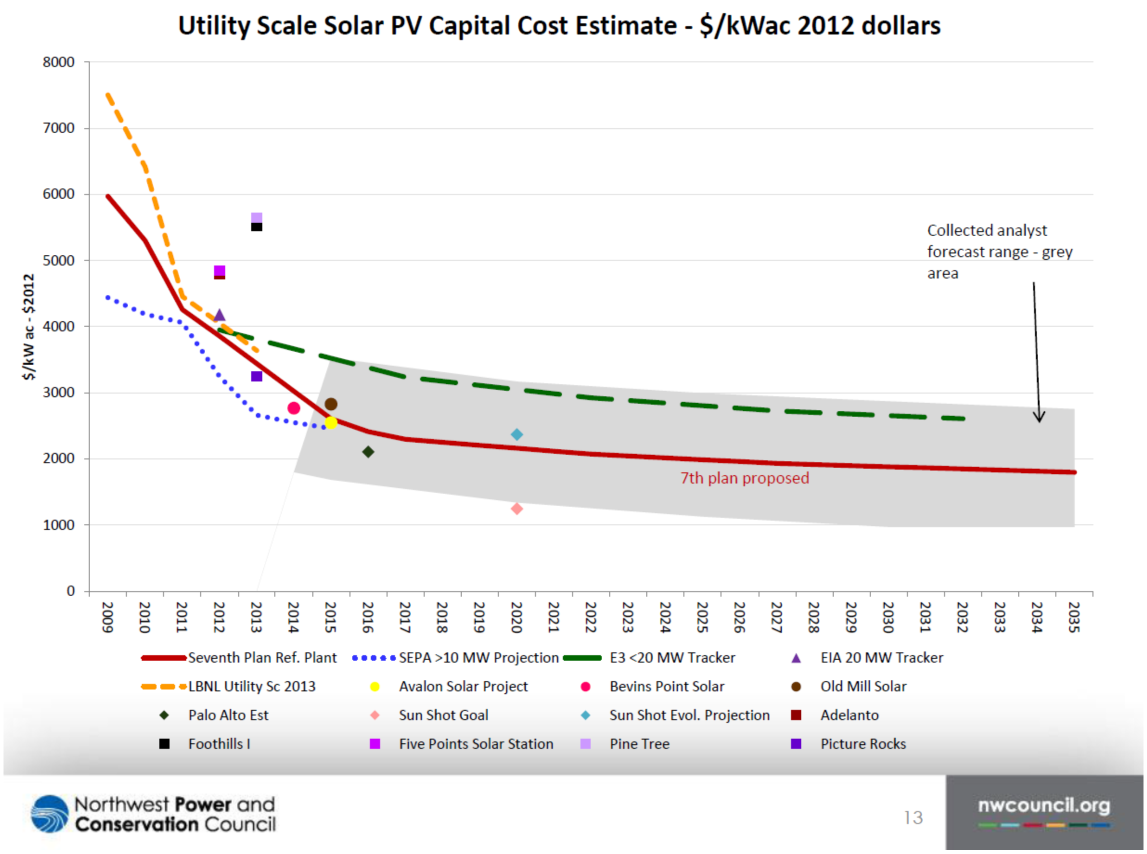


Figure 6-26 shows the impact of capital cost on solar levelized costs at a 20 percent capacity factor, and how this compares to wind and market. Based on the current projection of 2016 capital costs at $2,664 per kW, costs would have to decrease by over 50 percent to $1,283 per kW to be competitive with wind. In areas with higher solar potential the curve would shift down proportionally based on the capacity factor.

Figure 6-26: Solar PV Levelized Revenue Requirements

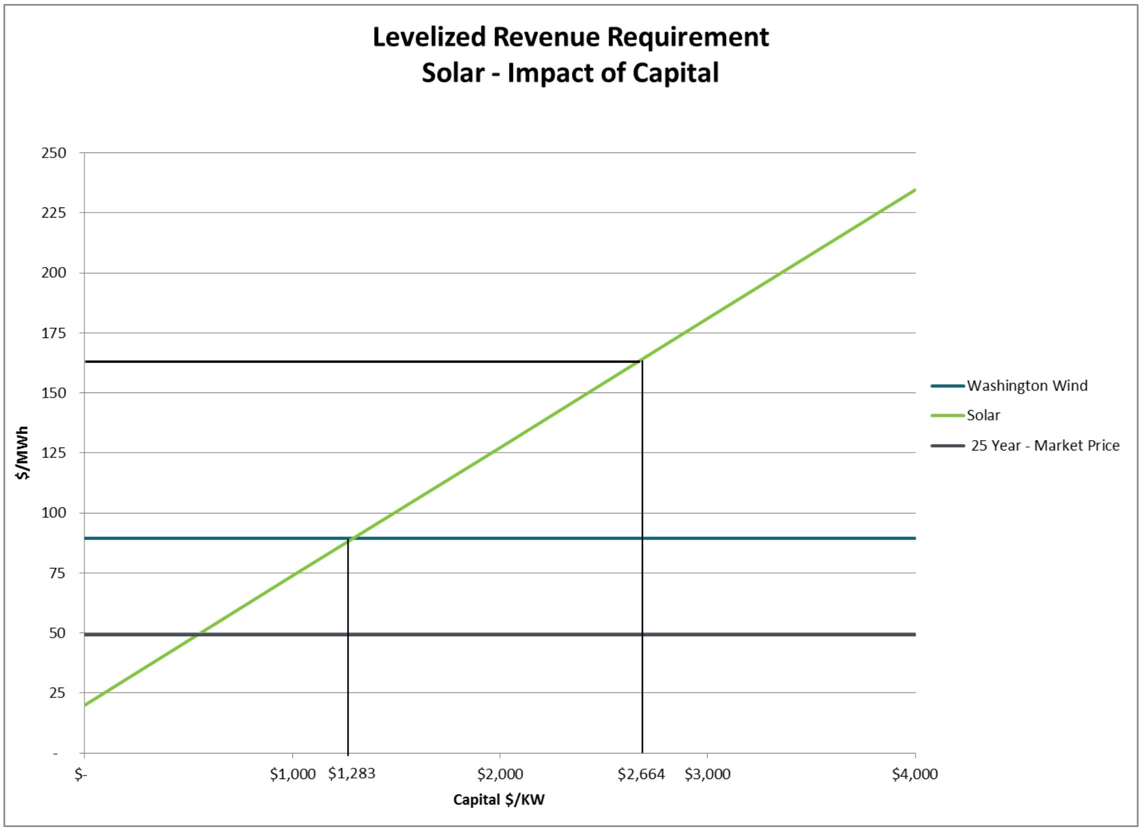
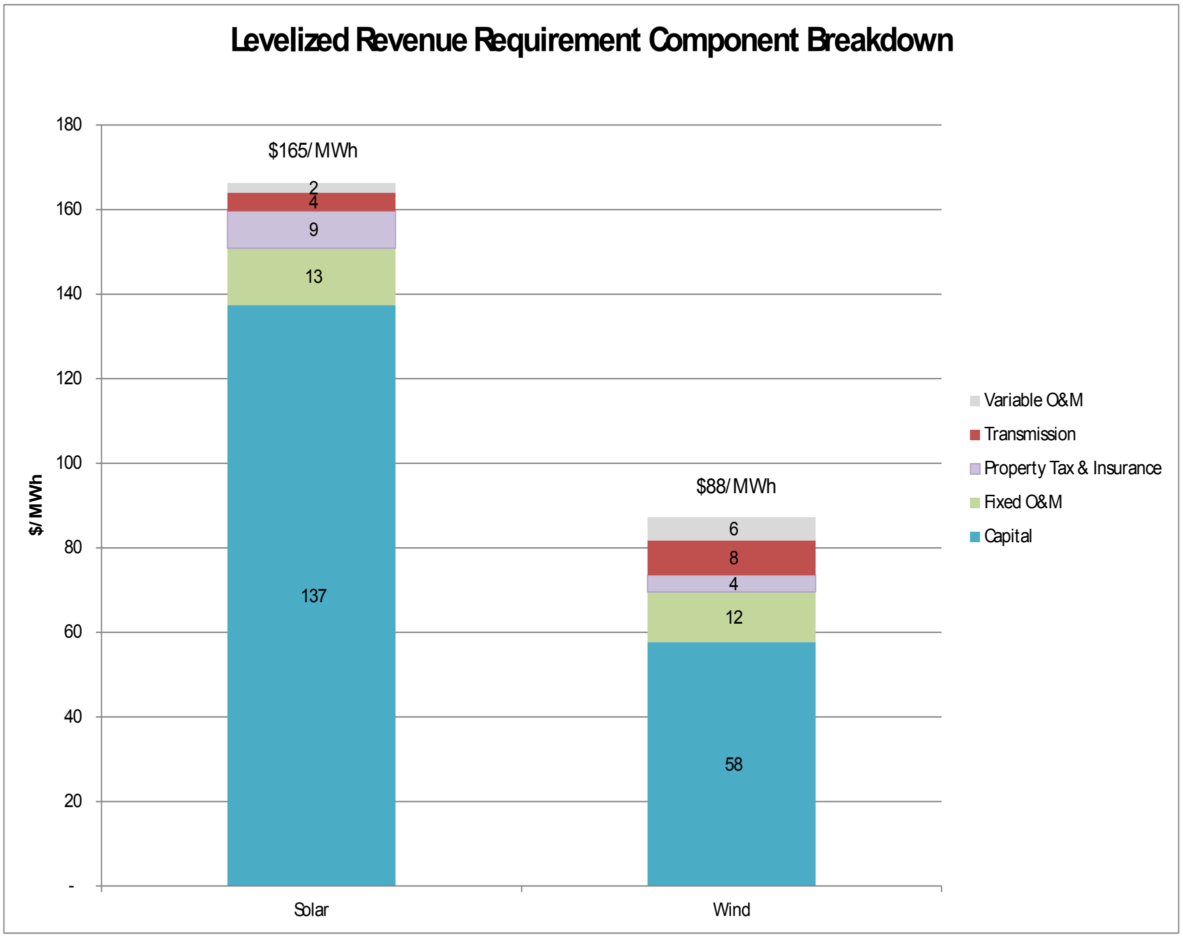


Figure 6-27 compares wind and solar cost components. Solar resources clearly have higher capital costs and lower capacity factors than wind resources, which makes it difficult for solar to compete with wind resources as a renewable alternative in Washington.

Figure 6-27: Wind and Solar Cost Components



SENSITIVITY ANALYSIS RESULTS USING 2013 PLANNING STANDARD

A. Colstrip

If Colstrip units are retired, what is the most cost-effective way to replace those resources?

Baseline: All four Colstrip units remain in service.

Sensitivity 1: Units 1 & 2 retire in 2026 (PSE owns 307 MW total capacity).

Sensitivity 2: All four units retire in 2026 (PSE owns 677 MW total capacity).

This sensitivity tested a “replacement power” portfolio analysis that took Colstrip out of PSE’s portfolio across three scenarios (Low, Base and High), so that we could compare the different portfolio builds. As part of the assumptions for Colstrip retirement, we also assumed that the Colstrip transmission capacity was available for wind resources in Montana, so the generic Montana wind costs were reduced to reflect this assumption. (See Scenario A in the Montana Wind sensitivity section of this chapter).

Baseline Result. When all four Colstrip units remain in service, frame peakers are chosen as the lowest cost resource addition in the Base Scenario.

Base Scenario Results. In the baseline portfolio, two frame peakers are added in 2026 to replace the Centralia contract and meet growing demand.

- When Colstrip Units 1 & 2 are retired in 2026, one additional frame peaker is added to replace the lost capacity (228 MW). Also, 300 MW of wind in Montana is added on top of the 300 MW of Washington wind for the RPS. The Montana wind plants become cost effective with the lower capital cost for transmission upgrades and the 55 percent capacity credit. If the capacity credit of MT wind is lower than 55 percent, then it is no longer cost effective.
- When all 4 units are retired in 2026, two CCCT units (385 MW each) and one frame peaker are added to replace capacity and meet growing demand instead of two frame peakers, along with an additional 300 MW of Montana wind. The CCCT plants become cost effective when retirements increase market prices, especially the spread between gas prices and power prices.

Low Scenario Results. In the Low Scenario portfolio, one frame peaker is added in 2026 to replace Centralia.

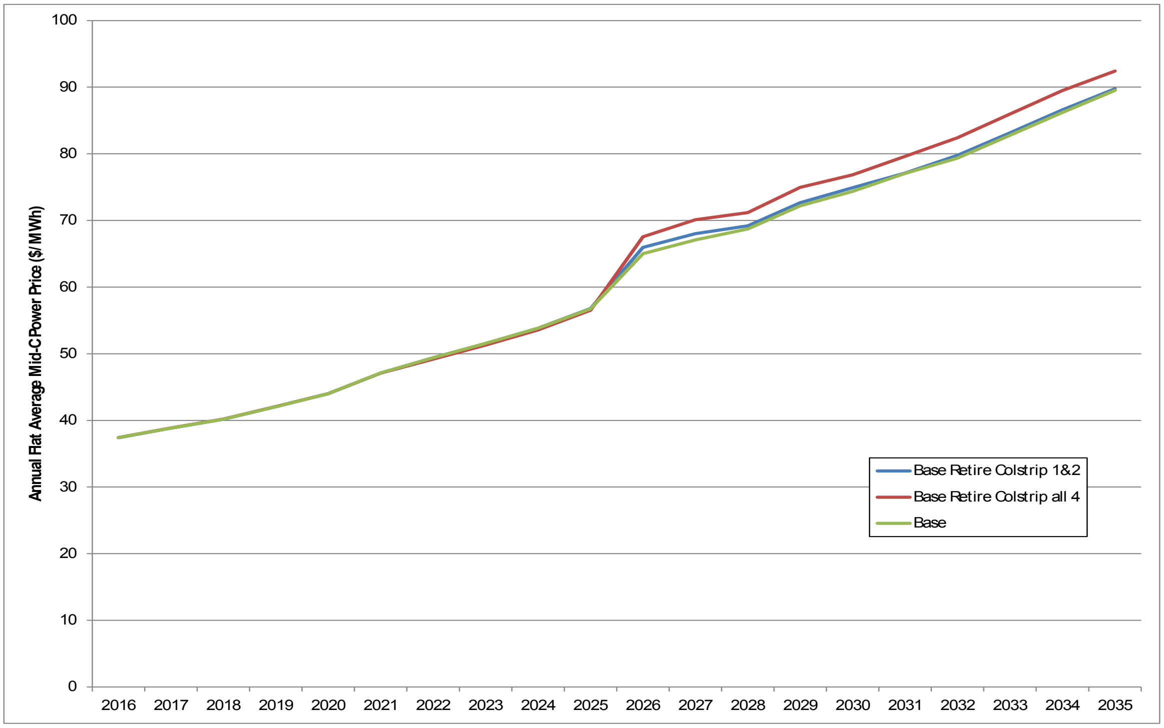
- When Colstrip Units 1 & 2 retire in 2026, two additional frame peakers are added to replace capacity, for a total of three frame peakers in 2026.
- When all four units retire in 2026, three additional frame peakers are added, for a total of four frame peakers in 2026.

High Scenario Results. In the High Scenario portfolio, one CCCT is added in 2026 to replace Centralia and meet growing demand.

- When Colstrip Units 1 & 2 retire in 2026, 500 MW of Montana wind is added (275 MW capacity), and additional DSR bundles are added to replace capacity.
- When all four units retire in 2026, the same DSR selected in the baseline case is retained (Bundle D), one CCCT plant is added to replace capacity, and 500 MW of Montana wind is added.

Figure 6-28 illustrates the significantly greater impact that removing all four Colstrip units has on wholesale market prices compared to removing Units 1 & 2 alone, as the effects ripple across the WECC. Tables of annual portfolio additions are located in Appendix N, Electric Analysis.

Figure 6-28: Forecast Mid-C Electric Prices with and without Colstrip Operating



B. 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 6-29 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. The avoided cost of energy, in particular, varies depending on the power price included in the scenario. Analysis of ramp rates continues to show that the sooner DSR is acquired, the more cost effective it is. In the 2011 IRP, a 10-year ramp rate was identified as the better option over the 20 year ramp rate used by the Council. (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 1,078 MW of DSR by 2035.

Figure 6-29: Optimal DSR Results across Scenarios for 2013 Planning Standard

	MW Additions by 2035	Bundle		Demand-response		DE	EISA	Total
1	Low	C	664	1,3,4,5	174	27	197	1,062
2	Base	D	683	1,3,5	172	27	197	1,078
3	High	D	683	1,3,4,5	174	27	197	1,081
4	Base + Low Gas Price	D	683	1,3,5	172	27	197	1,078
5	Base + High Gas Price	D	683	1,3,5	172	27	197	1,078
6	Base + Very High Gas Price	F	744	1,3,5	172	27	197	1,139
7	Base + No CO2	D	683	1,3,5	172	27	197	1,078
8	Base + High CO2	E	732	1,3,5	172	27	197	1,127
9	Base + Low Demand	C	664	1,3,4,5	174	27	197	1,062
10	Base + High Demand	E	732	1,2,3,5	254	27	197	1,209

Demand response is a subset of DSR and is considered as part of determining the least-cost resources. Demand-response programs were broken down into 5 categories:

1. Residential Direct Load Control (DLC) Space Heating
2. Residential DLC Water Heating
3. Residential Critical Peak Pricing (CPP)
4. Commercial and Industrial Critical Peak Pricing
5. Curtailment

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, 1,062 MW to 1,209 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 6-30: Effect of DSR on Costs and Risks

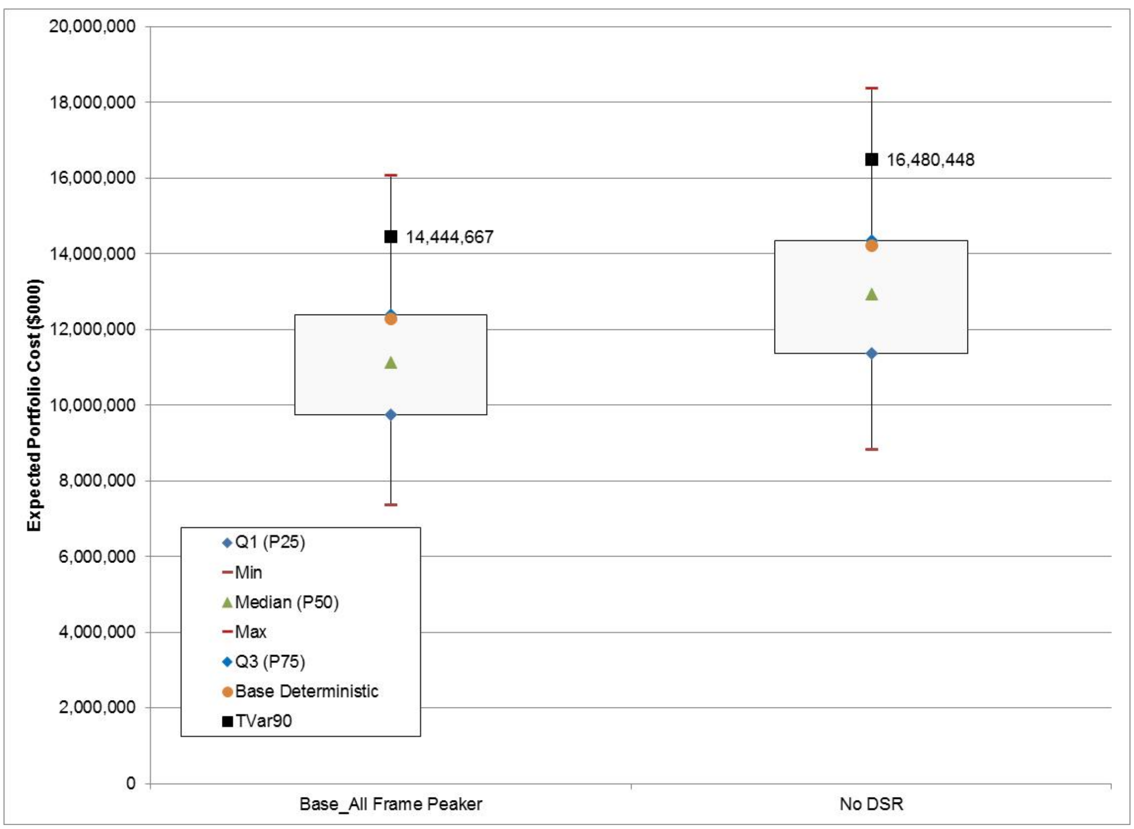


Figure 6-31 shows that DSR reduces power cost risk relative to no DSR. The Tail Var 90 of variable costs for the No DSR portfolio would be a little over $2.04 billion higher than the Base Scenario optimal portfolio with DSR. It also illustrates that the No DSR portfolio revenue requirement is $1.93 billion 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 6-31: 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	12.28	14.21	1.93
TVar90	14.45	16.48	2.04

C. Thermal Mix

How does changing the mix of thermal resources affect portfolio cost and risk?

Baseline: All peakers are selected in the Base Scenario portfolio.

Sensitivity 1: What happens when all CCCT plants are modeled?

Sensitivity 2: What happens when a mix of CCCT and frame peakers are modeled?

In this IRP, the lowest cost thermal resource varied between the frame peaker and the CCCT depending on the scenario. The all-peaker portfolio is the least-cost portfolio from the Base Scenario, the CCCT builds are based on the Base + High CO_2 least-cost portfolio and the mix of frame and CCCT portfolio is the least-cost portfolio from the Base + No CO_2 scenario.

Figure 6-32 compares the differences among portfolio costs compared to the tail value at risk (TVar90). TVar90[17] represents the downside financial risk associated with a portfolio; it is calculated as the average value of the worst 10 percent of outcomes.

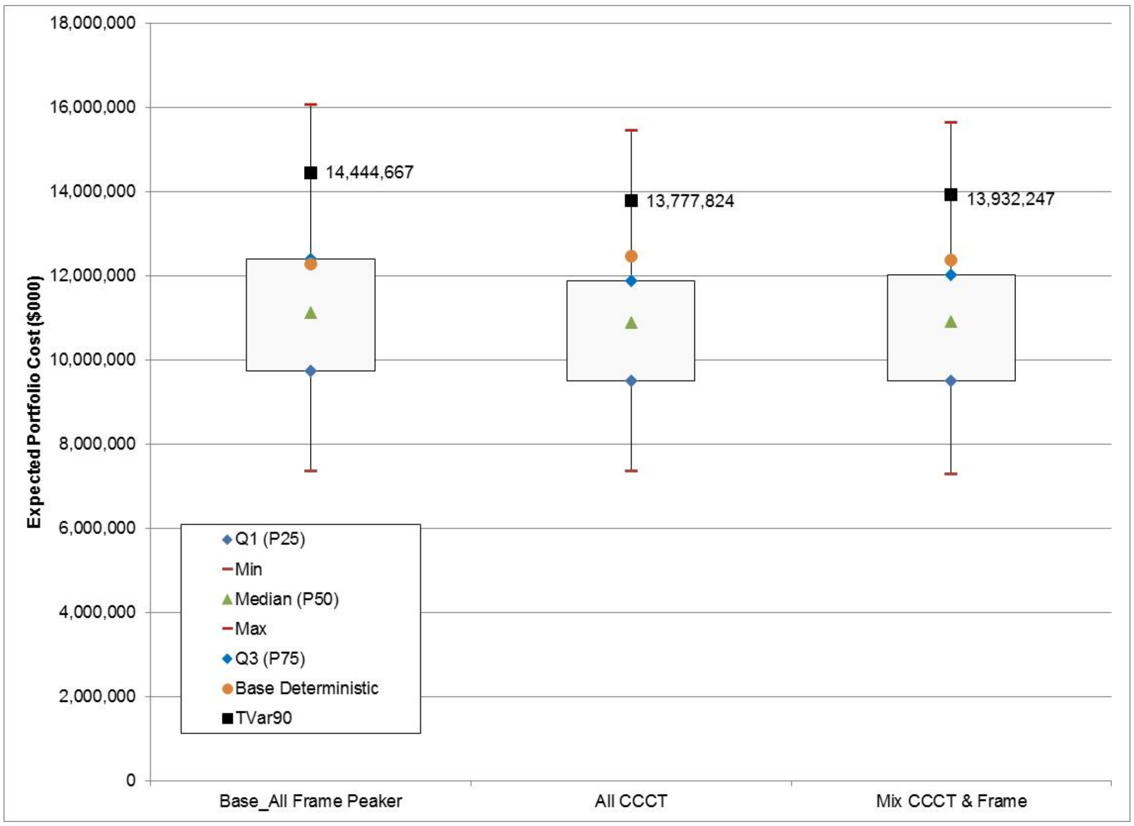
Figure 6-32: Thermal Mix – Total Portfolio Cost and TVar90

NPV ($ millions)	Base Deterministic Portfolio Cost	Difference from Base	TVar90	Difference from Base
Base (all Frame Peaker)	12,277	-	14,445	-
All CCCT	12,471	194	13,778	(667)
Mix CCCT & Frame	12,363	86	13,932	(512)

17 / Tail value at risk (TVaR) is also known as tail conditional expectation (TCE) or conditional tail expectation (CTE), is a risk measure associated with the more general value at risk. It quantifies the expected value of the loss given that an event outside a given probability level has occurred.

The all-CCCT portfolio adds $194 million to the deterministic portfolio cost, but saves $667 million in risk to the TVar90. The mixed portfolio adds $86 million to total portfolio cost, but saves $512 million in risk. In this analysis, the all-CCCT portfolio appears to be less risky because the benefit associated with the cost increase is greater than for the mixed portfolio. The box plots in Figure 6-33 chart the distribution of the three different portfolio costs.

Figure 6-33: Thermal Mix – Range of Portfolio Costs across 1,000 Trials



D. Gas Plant Location

What if gas plants are built in eastern Washington instead of PSE service territory?

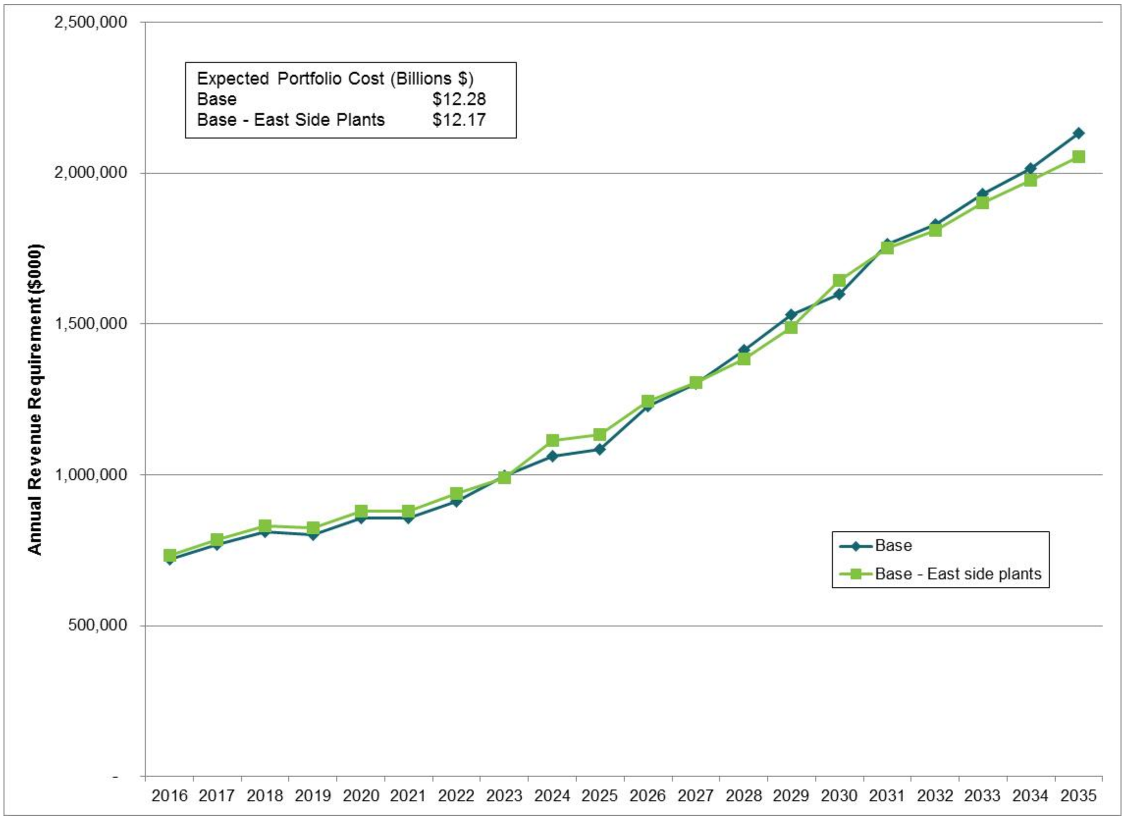
Baseline: Gas plants are located in PSE service territory.

Sensitivity: Model with gas transport and transmission costs from eastern Washington.

Resources located within PSE's balancing authority west of the Cascade mountains have higher fuel costs but would carry lower transmission costs than resources located on the east side of the mountains. East side resources incur lower fuel costs, but higher transmission costs since they require the purchase of transmission contracts from BPA to bring the power to our system. As a result, the Base Scenario portfolio with west side plants selects frame peakers as lower cost, but when the Base Scenario is modeled with east side plants, CCCT plants are lower cost and therefore selected in the portfolio.

Figure 6-34, below, indicates that overall costs over the 20-years are very close between these two scenarios. Resources built in eastern Washington would be located within BPA's balancing authority and subject to the risk of BPA transmission tariff pricing and policy changes. West side plants, on the other hand, give PSE access to all of the short-term operational benefits that thermal resources can provide (minute-to-minute up to sub-hourly). Access to these same benefits from east side plants would depend upon BPA transmission policies. Given these considerations, and the small difference in cost between the two, PSE chose to include west side peakers in the resource plan.

Figure 6-34: Annual Revenue Requirements and Total Portfolio Costs for Gas Plants Located East and West of the Cascades



E. Gas Transport/Oil Backup for Peaking Plants

What if peakers cannot rely on oil for backup fuel and must have firm gas supply instead?

> **Baseline: Peakers are modeled assuming they have 50 percent firm pipeline capacity with 48 hours of oil backup fuel.**
> **Sensitivity: Model plants with 100 percent firm pipeline capacity and no oil backup capability.**

PSE has been reviewing its simple cycle combustion turbines (SCCT) (aka: "peakers") that have the capability to generate with natural gas or distillate fuel oil to determine if oil generation would be adequate to keep these plants operating to meet extreme winter peak demand in winter months. Several components were involved in the review:

1. Supply of Backup Fuel: Current use practices, policies and oil generation capacity from peaker oil storage tanks,
2. Supply of Non-firm Gas Supply: Review of any excess existing firm gas pipeline capacity in the gas sales portfolio that could be available to serve the SCCT peaking plants, and
3. Demand/Need for Non-firm Gas Supply: Review of 2021 peaker generation modeled to meet gas sales demand during peak winter months.

CURRENT USE PRACTICES, POLICIES AND OIL GENERATION CAPACITY

PSE's run time on distillate fuel for winter months is limited to the capacity of the fuel oil tanks at each site because we have limited ability to quickly refill the tanks via tanker trucks during the inclement weather of winter months. The current policy is to keep 53 hours of oil in the tanks (48 hours for generation plus five hours for testing) - even though they have capacity to hold several more days. Based on the current air permits for the peaking plants, there are no constraints with running the plants on oil to meet peaking needs during the winter months as noted below.

See Figure 6-35 for more generation information for the peaking plants.

Figure 6-35: Peaking Plants, Summary Information

Simple Cycle Combustion Turbine (Peaker)	No. of Oil Tanks[1]	Oil Tank Capacity (gallons)	Oil use per Day (gallons)	Oil Gener-ation (days)	Peak Capacity (MW)	Oil gener-ation for 48 hours (MWh)	Generation per Tank of Oil (MWh)[2]
Whitehorn 2 & 3	1	5,914,971	340,938	17	168	8,064	69,952
Frederickson 1 & 2	1	4,070,766	340,935	12	168	8,064	48,142
Fredonia 1 & 2	1	5,914,971	455,832	6	234	11,232	36,364
Fredonia 3 & 4			207,720	6	126	6,048	19,581
Total		**14,282,295**	**1,345,428**		**696**	**33,408**	**174,038**

NOTES
Fredonia 1 & 2 and 3 & 4 share one oil tank.
Estimated generation at peak demand temperatures of 23 degrees.

REVIEW OF ANY EXCESS EXISTING FIRM GAS PIPELINE CAPACITY IN THE GAS SALES PORTFOLIO

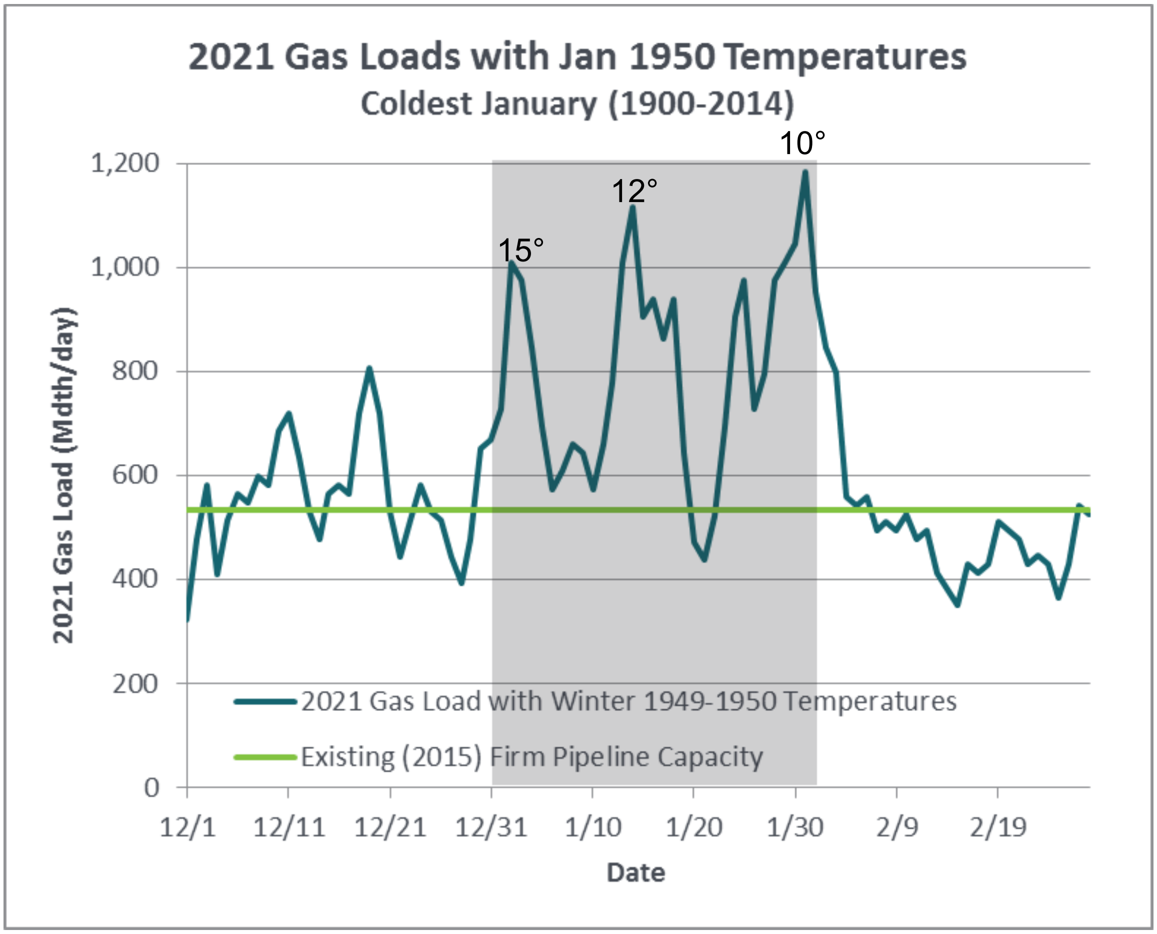
Will non-firm gas supply be available from Northwest Pipeline when the peakers need it, after consuming the fuel in their oil tanks? There is no gas industry organization that studies these kinds of questions, the way the NPCC's Resource Adequacy Advisory Committee studies regional electric supply. We can, however, study our own gas utility loads and resources in order to draw conclusions about the availability of non-firm fuel supply. Here we examine whether excess firm gas is available from the gas utility during peak days. Peak need was determined using the gas portfolio model (Sendout) and historical temperature data sets.

A historical temperature data set (1900-2014) for the region was obtained from the National Oceanic and Atmospheric Administration (NOAA). To create a long term data set we combined daily weather data from the Portage Bay Weather Station from 1900-1948 and from SeaTac International Airport from 1949-2014 to create a 114 year temperature record. Average daily temperatures were calculated as the average of the minimum temperature and maximum temperature.

Using the 114 years of daily historical temperature data, 114 gas load profiles were created with 2021 loads using the Gas Portfolio Model (GPM). Months with high gas loads (December and January) were examined further and compared to our existing daily firm gas pipeline supply (533 Mdth/day) to determine if the gas utility could meet the gas load using the firm pipeline supply.

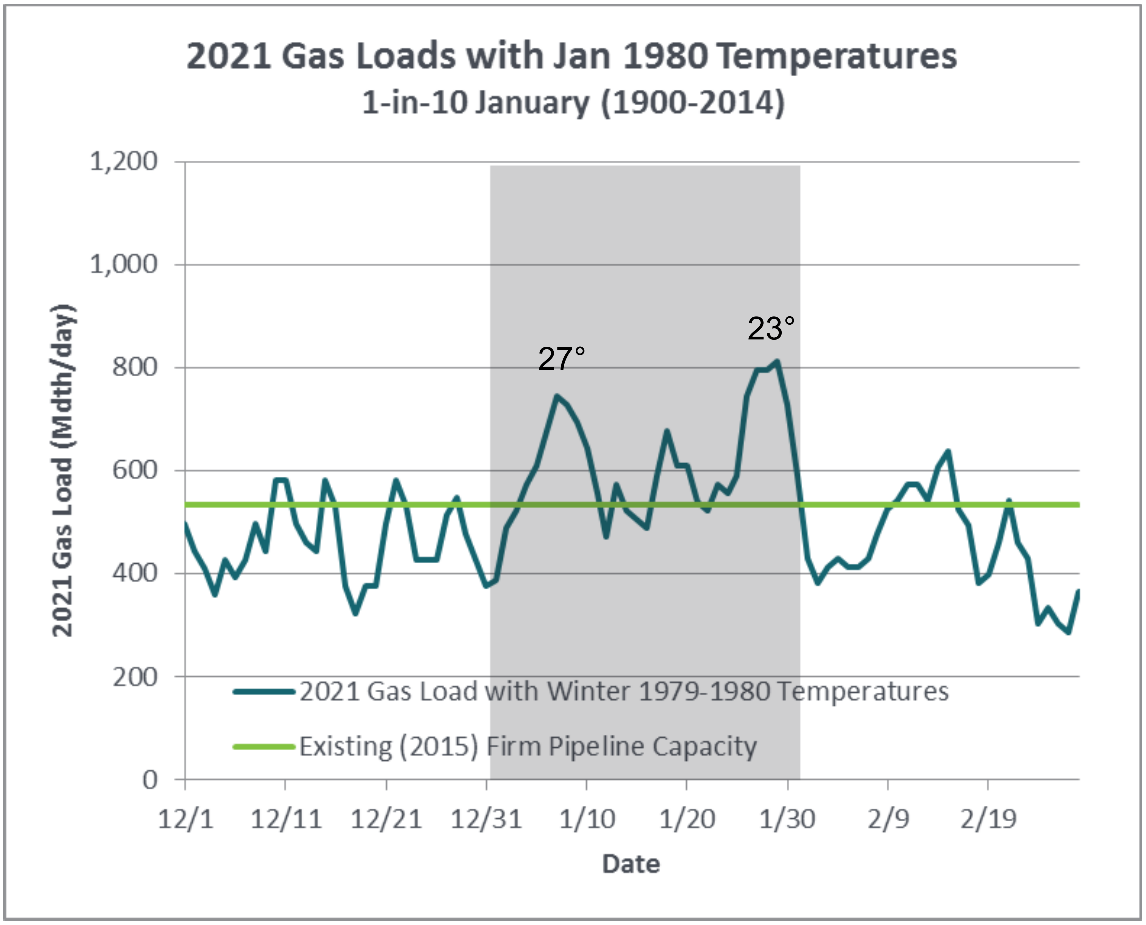
Below are three charts showing different possible 2021 gas loads using three different years of historical temperatures. Figure 6-36 shows December 1949 to February 1950 with January 1950 highlighted in grey. January 1950 was the coldest month in the 114 year dataset, with extreme cold spells occurring three times throughout the month. With 2021 gas loads and this temperature pattern, the demand is greater than the existing firm pipeline capacity for most of the month, only dropping below 533 Mdth/day for 3 days. In addition to the firm pipeline supply, fuel from Jackson Prairie storage can be used to meet gas and electric loads. Gas storage at Jackson Prairie can be withdrawn to meet loads, but is also refilled throughout the winter on lower load days. Therefore, even if the load was below 533 Mdth for the 3 days during this example, the fuel would likely go toward refilling Jackson Prairie storage and would not be available for running the peaking units to generate electricity.

Figure 6-36: 2021 Gas Sales Utility Loads with Winter 1949-1950 Weather



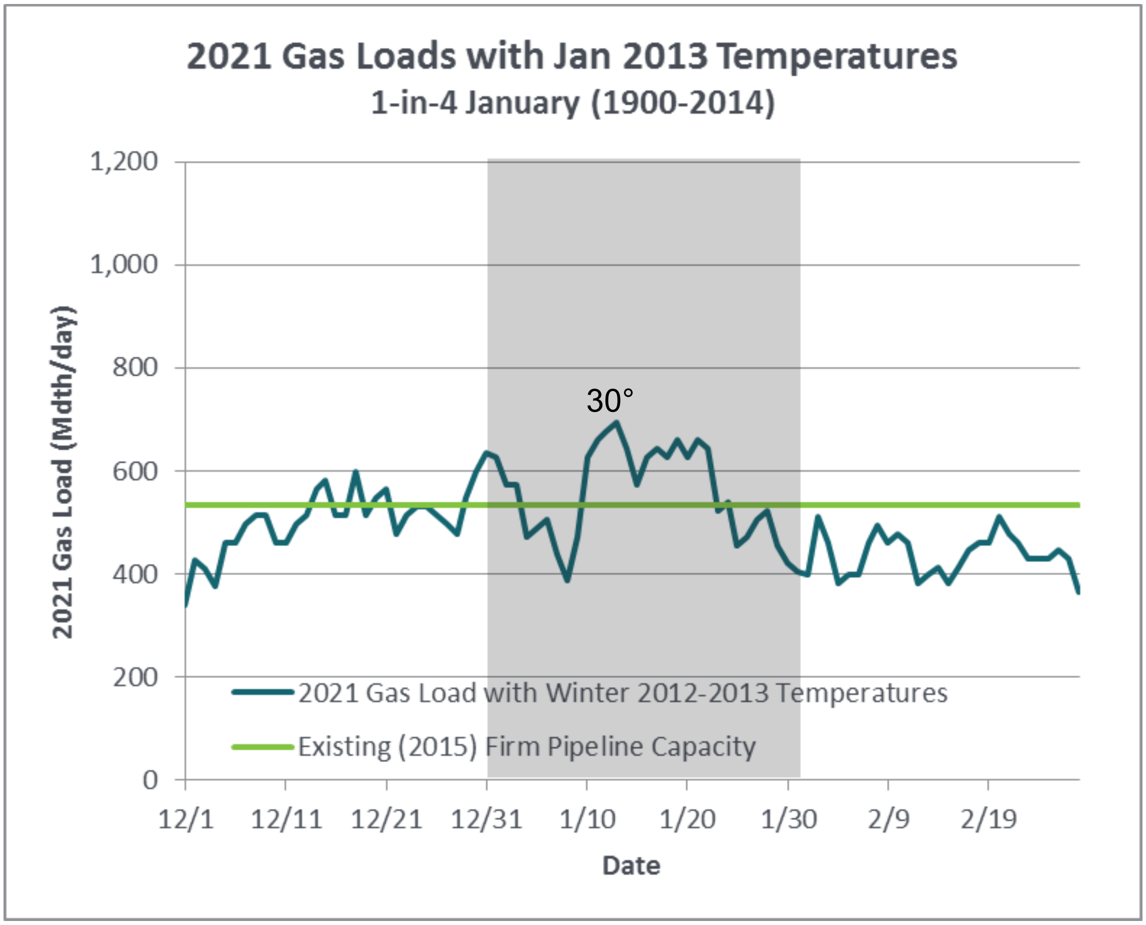
January 1950 was the most extreme month in the data set. January 1980 (Figure 6-37) represents a 1-in-10 January, meaning that 1-in-10 Januaries in the data set were as cold or colder than 1980. The January 1980 peak temperatures are higher than the January 1950, but the load is still above the firm pipeline capacity for much of the month, and therefore not available to run peakers during that time. In this example, 8 days had loads below 533 Mdth/day, however some or all of that excess volume would still go to refill storage and therefore, on those days, the fuel would not be available for running the peakers.

Figure 6-37: 2021 Gas Sales Utility Loads with Winter 1979-1980 Weather



A more recent and less extreme data set is January 2013 (Figure 6-38). In this data set, 17 days in January were above the existing firm pipeline capacity, so on those days there would be no excess pipeline capacity for peakers, and gas from storage would be used to meet gas utility loads.

Figure 6-38: 2021 Gas Sales Utility Loads with Winter 2012-2013 Weather



When loads are above the existing firm pipeline capacity (533 Mdth per day) there is no excess pipeline capacity for peakers and some or all of storage capacity is used to meet gas utility loads. When loads are below 533 Mdth per day in the winter some or all of the excess volume is being used to refill storage, depending on how storage volume that has been used, the monthly ending target for storage volume, and the short term weather forecast is. In more mild years some or all of this volume may be available to fuel the peaking units.

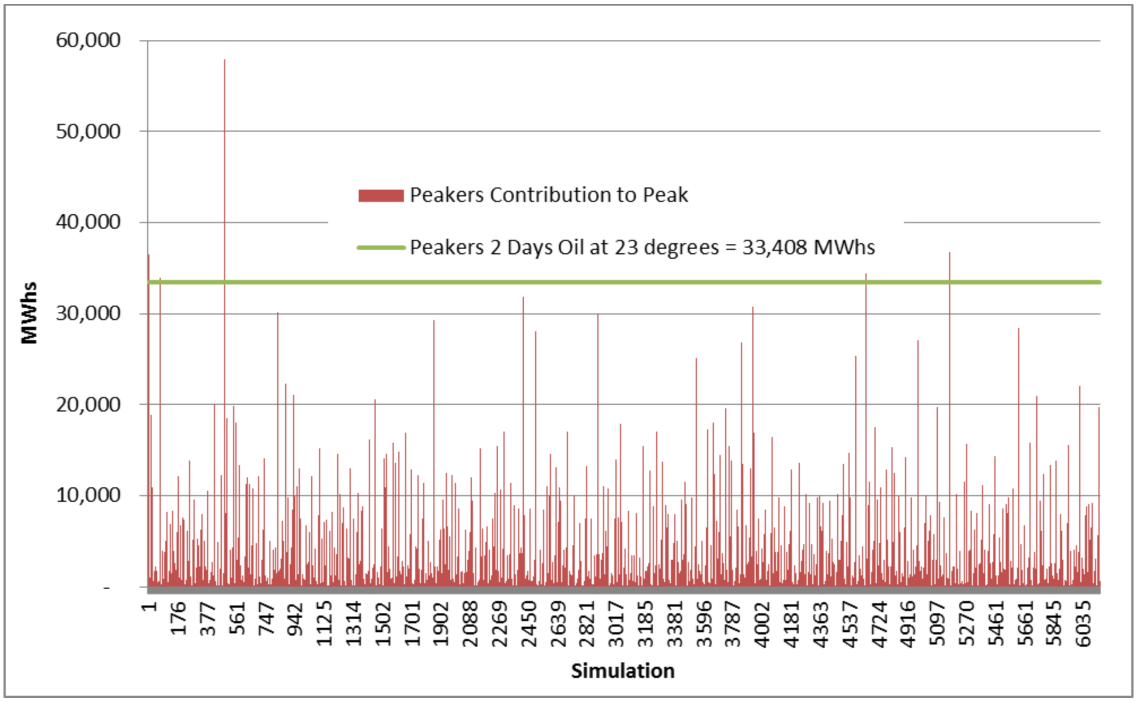
Therefore, there are times that the electric utility cannot rely on surplus gas supply for fuel for generation. These times are typically during cold weather events in the winter when the gas supply is peaking. Peakers are likely needed on cold days when there are peaks in the gas need.

REVIEW OF 2021 PEAKER GENERATION MODELED TO MEET GAS SALES DURING PEAK WINTER MONTHS

Having established that PSE's electric utility should not rely on non-firm fuel supply for extended periods in the winter, we turned our attention to whether existing oil inventories were sufficient. To examine this question, we used PSE's RAM to do a comparative sensitivity analysis. We started with a baseline case that included the peakers in the RAM, subject to the base forced outage rates and all other assumptions. The winter unserved energy in MWh was calculated in each of 6,160 simulations. We then performed another case, where all the dual-fueled peakers were excluded, and again calculated the MWh of unserved energy in each of 6,160 simulations. The additional MWh of unserved energy represents the number of MWh, by simulation, the peakers are needed to meet load across the entire winter. In this analysis, the only difference is inclusion of the dual-fuel peakers. Therefore, we can compare the MWh needed with the MWh that could be generated with 48-hours of oil supply in the tanks.

Figure 6-39 illustrates that the peakers are needed for reliability purposes in many simulations. However, the chart also illustrates 48-hours of oil inventory is sufficient to cover all but five of the 6,160 simulations. This analysis is conservative, in that it does not provide for the ability to refill the oil tanks at any time throughout the winter – the inventory is assumed to be fixed. Results of this analysis demonstrate that backup fuel for the existing units is sufficient. This analysis is not directly applicable to new peakers, but does provide important insights. That conclusion will be driven by whether backup fuel can be permitted at a specific location and by the maximum run hours allowed. We now have a framework for analyzing whether new peakers with backup fuel will need firm pipeline capacity.

Figure 6-39: Back-up Fuel for Existing Dual Fuel Units



F. Energy Storage and Flexibility

What is the cost difference between a portfolio with and without energy storage. How do energy storage resources impact system flexibility?

> **Baseline: Batteries chosen only if analysis selects them as lowest economic cost.**
> **Sensitivity 1: Add 80 MW battery in 2023 instead of economically chosen peaker.**
> **Sensitivity 2: Add 80 MW pumped hydro storage in 2023 instead of economically chosen peaker.**
> **Sensitivity 3: Add 200 MW of pumped hydro storage in 2023 instead of economically chosen peaker.**

The optimal portfolio in the 2015 IRP Base Scenario added an 80 MW battery in 2035, the final year of the study period, primarily because it was the right size needed for the price; when additional resources are first needed starting in 2021, most scenarios we analyzed added frame peakers in that year. This sensitivity analysis explores two energy storage alternatives to that selection, batteries and pumped hydro. The first year additional resources are needed according to the 2015 IRP Base Scenario demand forecast and 2013 planning standard is in 2023.

Pumped Storage. Pumped hydro is a proven storage technology: however, the facilities are very expensive to build and may have controversial environmental impacts. They also have extensive permitting processes and require sites with specific topologic and/or geologic characteristics.

The assumed overnight cost to construct pumped storage is $2,400 per kW in 2014 dollars as compared to $896 per kW for a frame peaker. The analysis assumes no benefit for ancillary services. 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 two sizes of pumped storage, 80 MW and 200 MW, adding them in 2023. As shown in Figure 6-40, 80 MW of pumped storage would increase portfolio cost by $200 million, and 200 MW of pumped storage would increase it by $638 million.

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 for the electric distribution network. Batteries can also provide ancillary services such as spinning reserves and frequency regulation, along with peak capacity.

Batteries were chosen in the deterministic portfolio for the Base Scenario in 2035 due to how they fit into the portfolio in the very last year of the peak capacity calculation. This sensitivity forces a battery into the portfolio build in 2023 that could provide 2 hours of maximum capacity at 80 MW. For purposes of the analysis, batteries are assumed to provide 100 percent peak capacity credit. Forcing the 80 MW battery into the portfolio build at 2023 increased the portfolio cost by $97 million. Batteries would have to provide $150 per kW in flexibility to match the optimal portfolio in the Base Scenario, which is above what would be deemed reasonable. As part of the operational flexibility analysis, batteries have a benefit of $99.52 per kw per year.

Figure 6-40: Battery and Pumped Storage Portfolio Cost

	NPV Portfolio Cost ($Millions)	Difference from Base
Base Portfolio[1]	12,277	
80 MW Pumped Storage in 2023	12,478	201
200 MW Pumped Storage in 2023	12,915	638
80 MW Batteries in 2023	12,374	97
80 MW Batteries in 2023 with $150/kw-yr Flexibility Value[2]	12,277	-

NOTES
1 Includes 80 MW of batteries in 2035
2 Represents the tipping point for the flexibility value to bring batteries in line with the base portfolio.

G. Reciprocating Engines and Flexibility

How do reciprocating engines affect system flexibility?

Baseline: Reciprocating engines chosen for portfolio only if deterministic analysis selects them as lowest economic cost.

Sensitivity 1: Add 75 MW reciprocating engine in 2023.

Sensitivity 2: Analyze lower costs for additional 75 MW reciprocating engine in 2023

Reciprocating engines could provide valuable operational flexibility benefits to the portfolio. Since they are able to start up relatively quickly and are able to quickly ramp up and down, they can be used for load balancing purposes and other ancillary services.

The 2013 IRP flexibility analysis was used as the basis for this sensitivity examination. The stochastic analysis developed over 50 simulations to model the 2013 IRP Base Scenario portfolio with an incremental reciprocating engine, a combined cycle plant and a frame peaker to calculate the expected annual savings in balancing costs as compared to the Base Scenario portfolio. Figure 6-41 summarizes the results..

Figure 6-41: Summary Results from 2013 IRP Stochastic Flexibility Analysis, 50 Simulations

Portfolio	Capacity (MW)	Expected Annual Balancing Savings ($)	Expected Annual Balancing Savings ($/kW Capacity)
Base Portfolio + CCCT	343	$800,000	$2.33
Base Portfolio + Frame CT	220	$1,037,000	$4.69
Base Portfolio + Recip	18	$328,000	$18.23

For the 2015 IRP, the fixed operations and maintenance (O&M) costs were adjusted for each type of generic resource based on the expected annual savings from the 2013 IRP analysis. In addition, capital cost estimates for reciprocating engines were also updated based on alternative pricing estimates from a secondary source. Finally, the analysis included a smaller 75 MW reciprocating engine option as a resource alternative in the portfolio optimization, since the Base Scenario analysis included only a 220 MW option. These capital costs and fixed O&M assumptions are shown in Figure 6-42.

Figure 6-42: 2015 Flexibility Analysis, Capital Cost and O&M Cost Assumptions

2015 IRP- Reciprocating Engines Resources

2014 $	Units	Original Recip Engine (Base)	Updated Recip Engine (Small Size)	Updated Recip Engine (Large Size)	Updated Recip Engine w/ Flexibilty (Small Size)	Updated Recip Engine w/ Flexibilty (Large Size)
ISO Capacity Primary	MW	220	75	224	75	224
Winter Capacity Primary	MW	220	75	224	75	224
Capacity DF	MW					
Capital Cost	$/KW	$1,599	$1,404	$1,175	$1,404	$1,175
O&M Fixed	$/KW-yr	$5.31	$5.31	$5.31	($12.92)	($12.92)

This sensitivity analysis shows the difference in portfolio cost between the Base Scenario least-cost portfolio, which selected no reciprocating engines, and an alternative portfolio optimized around a reciprocating engine that was forced into the portfolio in 2023, the first year additional resources are needed. The analysis was broken down into 3 cases, based on the degree of flexibility benefit used in the evaluation:

1. no flexibility benefit is included,
2. full flexibility benefit for all technologies is included, and
3. a 50 percent flexibility benefit is assigned to reciprocating engines, and full flexibility benefit is assigned to the other technologies.

Each analysis included 3 portfolio alternatives for comparison to the Base Scenario least-cost portfolio:

1. a portfolio in which the screening model was allowed to choose a 75 MW reciprocating engine option,
2. a portfolio which optimized around a 75 MW reciprocating engine option built in 2023, and
3. a portfolio which optimized around a 224 MW reciprocating engine option built in 2023.

The results are shown in Figure 6-43 on the next page.

Figure 6-43: Portfolio Sensitivity Analysis, Reciprocating Engines ($Millions)

NPV ($Millions)	No Flexibility Benefit		With Flexibility Benefit			With Flexibility Benefits at 50% for Recip Peakers		
	Portfolio Cost (a)	Difference from Base (b)	Portfolio Cost (c)	Difference from Base (d)	Value of Flexibility to Portfolio (e) = (a)-(c)	Portfolio Cost (f)	Difference from Base (g)	Value of Flexibility to Portfolio (h) = (a)-(f)
Base Portfolio	12,277		12,221		56	12,221		56
Recip Peaker 75 MW*	12,263	14	12,202	19	61	12,208	14	56
Recip Peaker 75 MW in 2023	12,282	(5)	12,212	10	70	12,221	1	61
Recip Peaker 224 MW in 2023	12,354	(77)	12,235	(13)	120	12,260	(40)	93

** Replaces battery in 2035 as cheaper alternative*

In all three cases, the analysis selects a 75 MW reciprocating engine build in 2035 rather than the battery selected in the Base Scenario optimal portfolio. The portfolio benefit ranges from $13.6 million to $19.5 million.

Forcing a 75 MW reciprocating engine into the 2023 portfolio build would result in a $5.0 million portfolio cost in the no flexibility case as compared to the Base Scenario optimal portfolio, a $9.5 million benefit in the full flexibility case, and $0.7 million benefit for the 50 percent flexibility case.

The benefit derived from the flexibility cases is really a comparison between a 75 MW reciprocating engine and a battery. The optimal portfolios in the flexibility cases indicate that building the 75 MW reciprocating engine in 2035 instead of 2023 provides a portfolio benefit of over $10 million. The larger build for reciprocating engines (224 MW in 2023) results in a higher portfolio cost that ranges between $13.4 million and $77.4 million, depending on the flexibility case.

On a dollars per kW basis, reciprocating engines are more expensive than frame peakers. The current results do not indicate a compelling need for reciprocating engines in the near term, but they have certain advantages that merit consideration. They can be installed in 18 MW increments that could provide a right-sizing approach, and they can provide added value through flexibility benefits. The flexibility of each type of technology needs to be further examined since the market is moving towards addressing the industry's flexibility needs.

H. Montana Wind

Update transmission cost for Montana wind to be more optimistic if Colstrip continues to operate. Will Montana wind be chosen in the lowest cost portfolio?

Baseline: Assume PSE cost estimate for transmission upgrades to Montana.

Sensitivity: Assume lower transmission cost estimate.

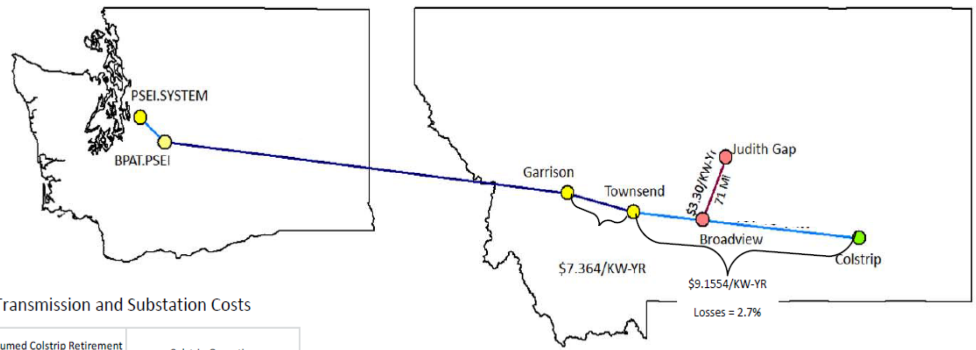
Montana wind has the benefit of higher capacity factors than Washington wind (41 percent versus 31 percent), but it also has the added costs of transmission to move the power to PSE's system. In addition, whether Montana wind qualifies as a qualifying renewable resource under RCW 19.285 depends on the location of the facility—most of the prime wind resources in Montana are outside the footprint defined in the law. Montana wind is viewed as a capacity resource that is compared to dispatchable resources used to meet peak capacity need in the analysis.

Additional analysis was done to examine Montana wind more closely. We assumed that the Montana wind project is located at Judith Gap, and did the analysis assuming Colstrip continues to operate and assuming there is excess transmission capacity with retirement of Colstrip. As shown below, this would require four transmission paths to deliver the power to PSE's system:

1. Wind facility (Judith Gap) to Broadview
2. Broadview to Townsend
3. Townsend to Garrison
4. Garrison to PSE's system

Broadview to Garrison is fully committed for Colstrip operations, therefore there is no excess capacity to accommodate additional wind capacity unless the transmission lines are upgraded or some of Colstrip is retired. With additional transmission losses of 6.7 percent as shown in Figure 6-44 below, the 41 percent capacity factor at the source is effectively 38 percent when delivered to PSE's system. The capacity factor for Washington wind is 34 percent. Montana wind also incurs the added annual cost of transmission for each of the transmission segments. See the transmission map in Figure 6-46 for the transmission path from Montana.

Figure 6-44: Montana Wind Transmission Paths



Transmission and Substation Costs

Assumed Colstrip Retirement Colstrip Operating	Colstrip Operating
A) $32.4 Million- Upgrade JG-Broadview Line	C) $662 Million- Upgrade JG-Broadview Line + Expand Broadview Sub + New Broadview-Garrison Line + Expand Garrison Sub
B) $94.2 Million- New JG-Broadview Line + Broadview Sub. Upgrade	D) $724 Million- New JG-Broadview Line + Expand Broadview Sub + New Broadview-Garrison Line + Expand Garrison Sub

*Right Of Way costs are not included in estimate of new transmission lines
*Assuming plant size of 265 MWs
*Costs only reflect additional substation/transmission equipment does not include transmission wheeling or cost to build wind facility
*Overheads not included

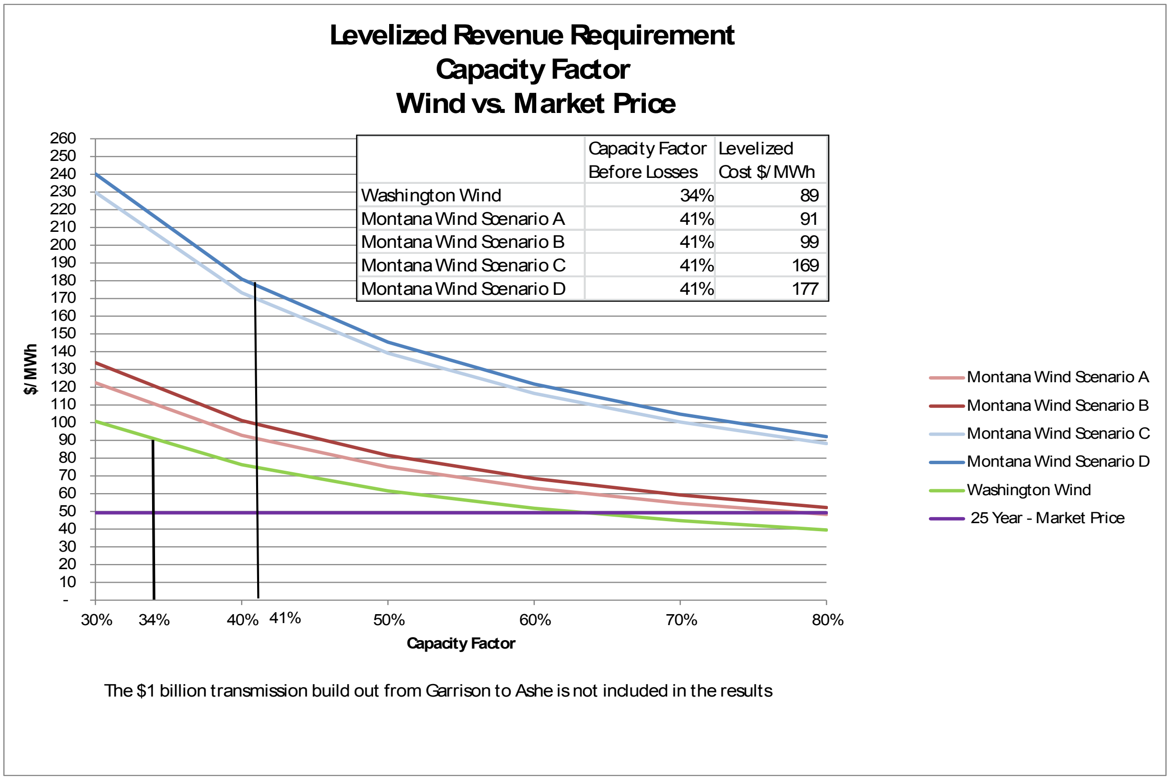
Wind Capacity	Percentage
MT Wind Capacity Factor	41.00%
Loss Factor	6.70%
Wind Capacity Net of Losses	38.30%
Transmission Costs	**$/KW-Year**
Judith Gap to Broadview	$ 3.3000
Broadview to Townsend	$ 9.1550
Townsend to Garrison	$ 7.3640
Total	**$ 19.8190**
$/MWh	**$ 5.5200**

The sensitivity analyses and incremental transmission costs are as follows. The costs in the following scenarios include three substations at the wind facility.

A. Colstrip Retired
   - Upgrade current NorthWestern line from wind facility to Broadview
   - $32.4 million - $122 per kW
B. Colstrip Retired
   - Build new line from wind facility to Broadview
   - $94.2 million - $355 per kW
C. With Colstrip Operations
   - Upgrade current NorthWestern line from wind facility to Broadview
   - Upgrade Colstrip line to Garrison
   - $662 million - $2,489 per kW
D. With Colstrip Operations
   - Builds new line from wind facility to Broadview
   - Upgrade Colstrip line to Garrison
   - $723 million - $2,728 per kW

Figure 6-45 shows the impact of the levelized costs versus capacity factor of wind as compared to market price.

Figure 6-45: Levelized Costs and Capacity Factors Compared, Montana Wind, Washington Wind and Market Price



	Capacity Factor Before Losses	Levelized Cost $/MWh
Washington Wind	34%	89
Montana Wind Scenario A	41%	91
Montana Wind Scenario B	41%	99
Montana Wind Scenario C	41%	169
Montana Wind Scenario D	41%	177

The results are as follows:

- Washington wind is comparable to market purchases at about a 65 percent capacity factor.
- Montana wind is $2 to $10 per MWh higher than Washington wind in the Colstrip Retired-Low Cost Scenario A.
- Montana wind is $80 to $88 per MWh higher than Washington wind in the Continued Colstrip-High Cost Scenario D.
- Montana wind is not selected as a resource in the optimization model.

Wind Scenarios. PSE analyzed an additional Montana wind scenario that included lower cost estimates in response to requests by interested parties. The assumptions for that analysis are listed below, followed by the results of the analysis in Figure 6-46.

1. Capital costs were reduced from $4,913 to $2,381 per kW,
2. Montana transmission line losses were reduced from 6.7 percent to 5.4 percent, and
3. Transmission costs were reduced from $55.05 to $51.75 per kW per yr.

Figure 6-46: Reduced Cost Montana Wind Analysis

Wind Costs

2014 $	WA Wind	MT Wind Base	MT Wind Update
Capital Cost Facility ($/kW)	$1,703	$1,703	$1,703
Sales Tax ($/kW)	$123		
Transmission/Substations ($/kW)		$2,813	$507
AFUDC ($/kW)	$141	$396	$171
Total Capital Cost ($/kW)	$1,968	$4,913	$2,381
Northwestern Line Losses		4.0%	2.7%
PSEI Colstrip Line Losses		2.7%	2.7%
Montana Losses		6.7%	5.4%
BPA Line Losses	1.9%	1.9%	1.9%
Total line losses	1.9%	8.6%	7.3%
Capacity Factor	34%	41%	41%
O&M Variable ($/MWh)	$3.15	$3.15	$3.15
Variable Transmission ($/MWh)	$1.84	$1.84	$1.84
Northwestern to Broadview		$3.30	$0.00
PSE tariff - Broadview to Townsend		$9.16	$9.16
BPA tariff - Townsend to Garrison		$7.36	$7.36
BPA tariff - Garrison to PSE	$35.23	$35.23	$35.23
Total Fixed Transmssion Cost ($/kW-yr)	$35.23	$55.05	$51.75
O&M Fixed ($/kw-yr)	$27.12	$27.12	$27.12

An important factor for comparing Montana wind to a dispatchable capacity resource is the capacity credit to meet peak loads. That is, what is the ICE for Montana wind? Hourly data is necessary to develop capacity credits, and though information over a number of years exists for the annual capacity factor, the hourly data is limited. However, PSE was provided with hourly Montana wind data for a 2-year period. This data indicated a peak capacity credit for a site at Judith Gap of 55 percent with an annual capacity factor of only 41 percent. Comparatively, Washington wind, for which we have 9 years of hourly data, provides only an 8 percent peak capacity credit. The validity of the peak capacity credit for Montana wind needs to be verified over a longer time period. Also, the capacity contribution of Montana wind was based on a 5% LOLP method for calculating the ICE—it was not updated to use 10.9 MWh EUE. We will shift to the EUE approach in future IRPs. .

See Figure 6-47 for the Montana wind results assuming continued operations at Colstrip. The base case did not select Montana wind given the prohibitively high capital costs of $4,913 per kW. The analysis below assumes a 300 MW Montana Wind build in 2023 at the reduced capital cost of $2,381/kW; but this is still high relative to Washington wind at $1,968 per kW. The analysis assumes the Montana wind does not qualify for the renewable portfolio standard given its location in Montana near Judith Gap; therefore it is viewed only as a peak capacity resource. The peak capacity credit was varied from 55 percent to 40 percent for Montana wind to test how high the capacity credit would need to be for Montana wind to be cost effective. This resulted in an increase in portfolio costs ranging from $184 to $226 million.

Figure 6-47: 300 MW Montana Wind added in 2023, tested at four different Capacity Credits

NPV (Millions $)	Portfolio Cost	Difference from Base Benefit/(Cost)
Base Portfolio (no MT Wind)	$12,277	
Add 300 MW MT Wind with 55% capacity credit	$12,462	($184)
Add 300 MW MT Wind with 50% capacity credit	$12,474	($197)
Add 300 MW MT Wind with 45% capacity credit	$12,483	($206)
Add 300 MW MT Wind with 40% capacity credit	$12,503	($226)

I. Solar Penetration

What if customers install significantly more rooftop solar than expected?

Baseline: Rooftop solar growth based on forecast of current growth trends.

Sensitivity: Assume maximum capture of rooftop solar.

Distributed solar generation has never been selected in the portfolio analysis as a cost-effective resource for the PSE system, but federal tax credits and state production incentives have made it cost-effective for customers. Already, PSE has 2,800 net-metered customers who have installed rooftop solar panels totaling 17.4 megawatts of capacity and 17,360 megawatt hours of annual energy, and we expect many more customers will install solar panels in the future.

For this IRP, the Cadmus Group prepared a system-wide study that explored the maximum potential for rooftop solar within the PSE system. It asked how much distributed solar might be added to the system in two scenarios:

1. if federal and state incentives are renewed, and
2. if incentives are allowed to sunset.

The Baseline assumption for portfolio modeling allowed the incentives to expire. This resulted in an additional 3 MW nameplate capacity or 0.18 aMW by 2035 that was added to the portfolio as a no-cost resource that reduced demand.

The sensitivity analysis assumed that all federal and state incentives were renewed; this resulted in a total of 309 MW nameplate capacity or 36.7 aMW of additional rooftop solar. The additional solar PV will reduce the total energy needed for the portfolio, but will not change the amount of capacity needed, since PSE’s system peak occurs during December before sunrise or after sunset, it does not contribute towards peak. So the sensitivity with the additional 36.7 aMW of solar has a lower total expected portfolio NPV than the Base Scenario portfolio by $65.59 million due to the lower market purchases needed, but the portfolio builds are exactly the same.

J. Carbon Reduction

How does increasing renewable resources and DSR beyond requirements affect carbon reduction and portfolio costs?

Baseline: Renewable resources and DSR per RCW 19.285 requirements.
Sensitivity 1: Add 300 MW of wind beyond renewable requirements.
Sensitivity 2: Add 300 MW of utility-scale solar beyond renewable requirements
Sensitivity 3: Increase DSR beyond requirements.

Wind. In this analysis, 300 MW of wind was added to the portfolio in 2021 and the changes in portfolio costs and emissions relative to the least-cost portfolio in the Base Scenario were used to calculate the incremental cost per ton over the 25-year period 2021-2045. The 25-year analysis period was chosen as it represents the depreciable life of the wind plant.

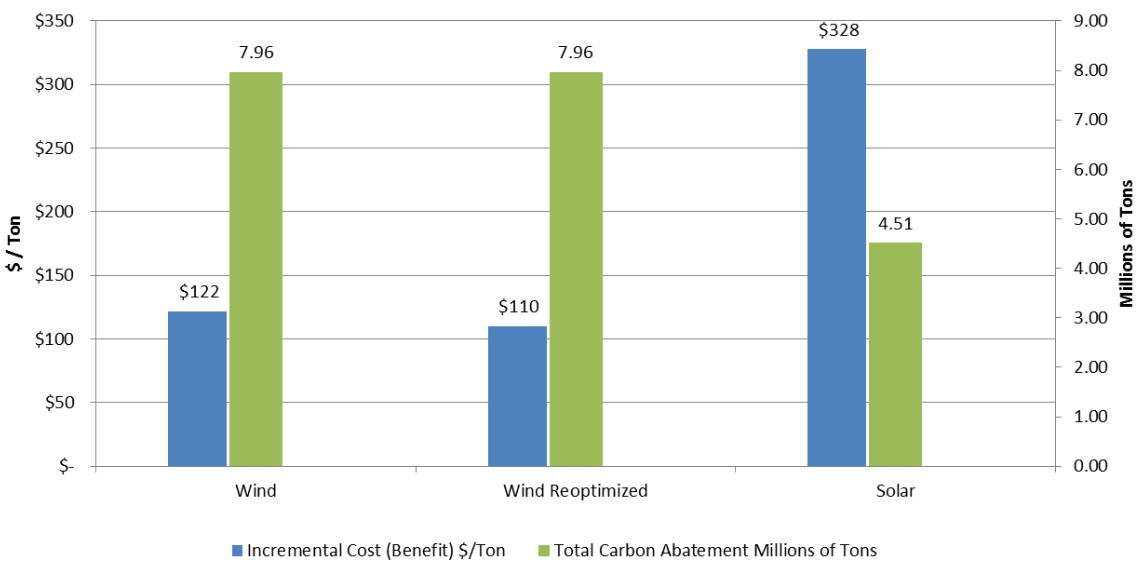
For the first case, the wind was added without re-optimizing the portfolio in order to determine its impact as a stand-alone resource. In a second case, the portfolio model was re-optimized to determine the additional wind's impact on the portfolio. In this case, demand-side resources were fixed at the levels selected in the optimal Base Scenario portfolio to isolate the impact on supply-side resources. The addition of wind resulted in one-year delays in the acquisition of two peakers during the 20-year planning horizon relative to the Base Scenario optimal portfolio.

In addition to examining Montana wind, this IRP also includes an analysis of adding an additional 300 MW of wind in 2021, above and beyond the amount required by the RPS. When modeling wind for the RPS, we include the cost of replacing the plant at the end of its useful life as part of the end effects, but for examining the cost of this extra wind, we did not, so that the results would focus on only the impact of this wind on PSE portfolio costs.

Solar. For the solar analysis, 300 MW of utility-scale solar was added to the optimal Base Scenario portfolio in 2021. Because solar does not contribute to the peak capacity need, it was not necessary to re-optimize the portfolio model.

Wind and Solar Results. For the wind and solar analyses, the purpose was to estimate the changes in portfolio cost and emissions that resulted from these additions, and to estimate the incremental cost of reducing emissions on a dollar-per-ton basis. In this analysis, all the changes in portfolio cost are included in the unit cost of carbon abatement, whereas in reality, the addition of a resource brings other benefits as well. Total incremental carbon abatement and the incremental cost per ton that resulted are presented in Figure 6-48.

Figure 6-48: Additional 300 MW Wind or Solar,
Incremental Revenue Requirement and Total Carbon Abatement, 2021-2045



Incremental revenue requirement per ton of emissions relative to base scenario, levelized over 25 years. Sum of carbon abatement over 25 years relative to base scenario.

In all three analyses, adding a renewable resource increases portfolio cost and reduces emissions. The incremental cost of carbon abatement is estimated at $122 per ton when wind is added without re-optimizing the portfolio, $110 per ton when adding wind and re-optimizing, and $328 per ton when solar is added. These results are presented in Figure 6-49.

Figure 6-49: Additional 300 MW of Wind or Solar, Incremental Cost per Ton of Carbon Abatement, 2021-2045

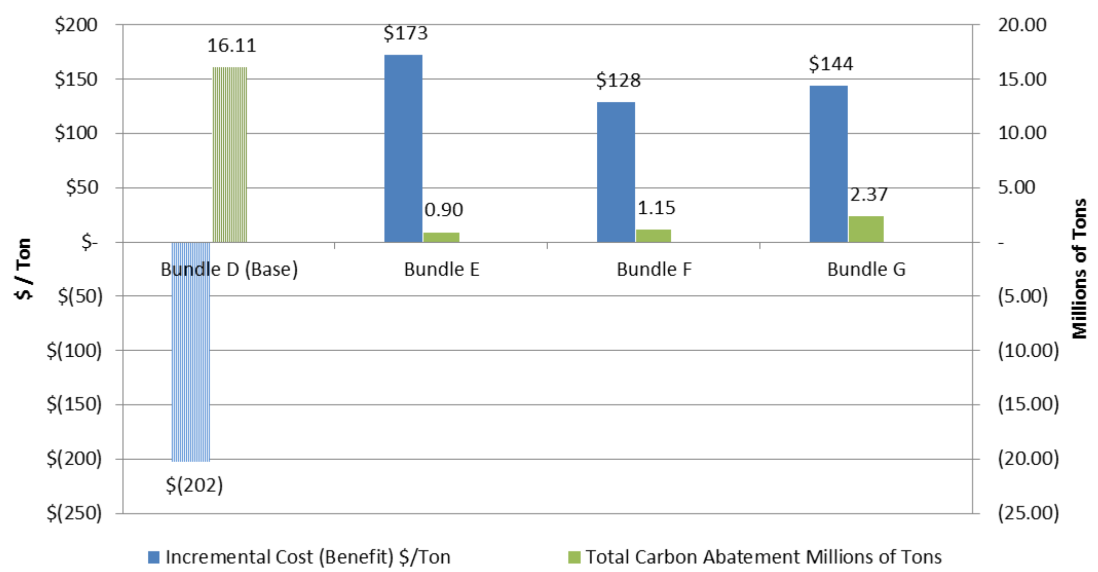
(Thousands $)	Wind	Wind Re-optimized	Solar
Base Scenario NPV Expected Cost	$12,008,998	$12,008,998	$12,008,998
NPV Expected Cost	$12,431,986	$12,391,240	$12,653,231
NPV Incremental Cost	$422,989	$382,242	$644,233
Levelized Cost ($Thousands / Year)	$38,849	$35,107	$59,170
Avg. Incremental Emissions (Millions Tons/Year)	(0.32)	(0.32)	(0.18)
Incremental Cost ($ / Ton)	$122	$110	$328

Demand-side Resources. Analysis of additional DSR bundles began with the optimal portfolio for the Base Scenario, which includes DSR bundles A through D; this was compared to the Base Scenario with no DSR. Then, bundle E was added to the optimal portfolio with DSR and the portfolio was re-optimized; these results were compared to the scenario with bundle D. Bundles F and G were also added incrementally and compared to the optimal portfolio with bundle D.

When bundles A through D are added to the portfolio without DSR, there is a $1.3 billion reduction in portfolio cost and a 16 million ton reduction in emissions over the 20-year planning horizon (2016-2035). This results in an incremental benefit of $202 per ton. Including this amount of DSR reduces the number of thermal resources built because it reduces the peak capacity need. It also reduces the number of renewable resources built because it reduces the overall energy need that determines the RPS requirement. When additional DSR bundles are added, the incremental emissions abatement is relatively small and occurs at a cost. The addition of bundle E delays some supply-side resources by one year, but the cost savings from the delays do not offset the cost of the additional DSR and the incremental cost is $173 per ton. With the addition of bundle F, portfolio cost declines a marginal amount relative to portfolio with bundle E; this is the result of other changes in the model when the portfolio is re-optimized, including a change in demand-response bundles. Adding Bundle G results in additional delays of supply-side resources, but the reduced costs do not offset the increased cost of demand-side resources.

Incremental cost per ton for each DSR configuration relative to the Base Scenario, along with total incremental carbon abatement, is presented in Figure 6-50.

Figure 6-50: Additional DSR, Incremental Revenue Requirement and Total Carbon Abatement by Bundle, 2016-2035



Bundle D is relative to base scenario without demand side resources; subsequent bundles are relative to base scenario with bundle D. Costs are levelized over 2016-2035. Abatement is 2016-2035 total relative to reference scenario.

Overall, supply-side resources are delayed but not eliminated in these sensitivity analyses. Demand-response programs change with the addition of DSR bundles, and carbon emissions are achieved – but at an incremental cost that is not economic. These results support the Base Scenario optimal portfolio finding in which bundle D was chosen as the most cost effective DSR bundle.

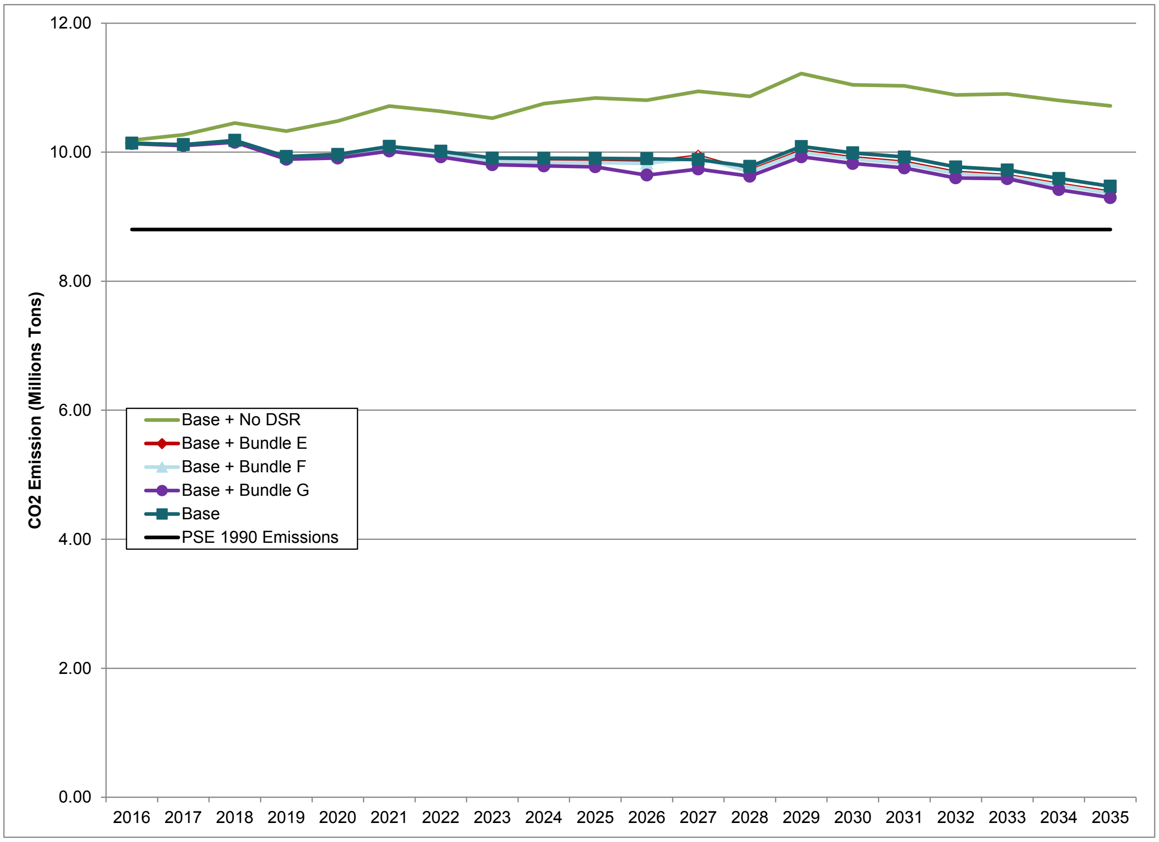
Figure 6-51: Incremental Cost per Ton of Carbon Abatement by DSR Bundle, 2016-2035

Thousands $	Bundle D (Base)	Bundle E	Bundle F	Bundle G
Base w/o DSR NPV Expected Cost	$12,339,055	$12,339,055	$12,339,055	$12,339,055
NPV Expected Cost	$11,019,322	$11,077,321	$11,075,068	$11,155,377
NPV Incremental Cost (Benefit)[1]	($1,319,733)	$58,000	$55,747	$136,055
NPV Incremental Emissions (Millions of Tons)[1]	-6.52	-0.34	-0.43	-0.95
Incremental Cost (Benefit) ($ / Ton)[1]	($202)	$173	$128	$144

NOTE: Bundle D is relative to Base Scenario without DSR; others are relative to Base Scenario with bundle D.

DSR and wind resources affect emission rates, but to a much smaller extent than Colstrip or the Coal Transition PPA. Figure 6-52 illustrates the effect that additional DSR has on portfolio emission rates for the Base Scenario. By 2035, the DSR in the Base Scenario least-cost deterministic portfolio, which includes Bundle D, reduces CO_2 emissions by 1.25 million tons annually, but this does not get the portfolio to 1990 levels.

Figure 6-52: Emissions by Portfolio (Base refers to the least-cost, deterministic portfolio in the Base Scenario which includes Bundle D)



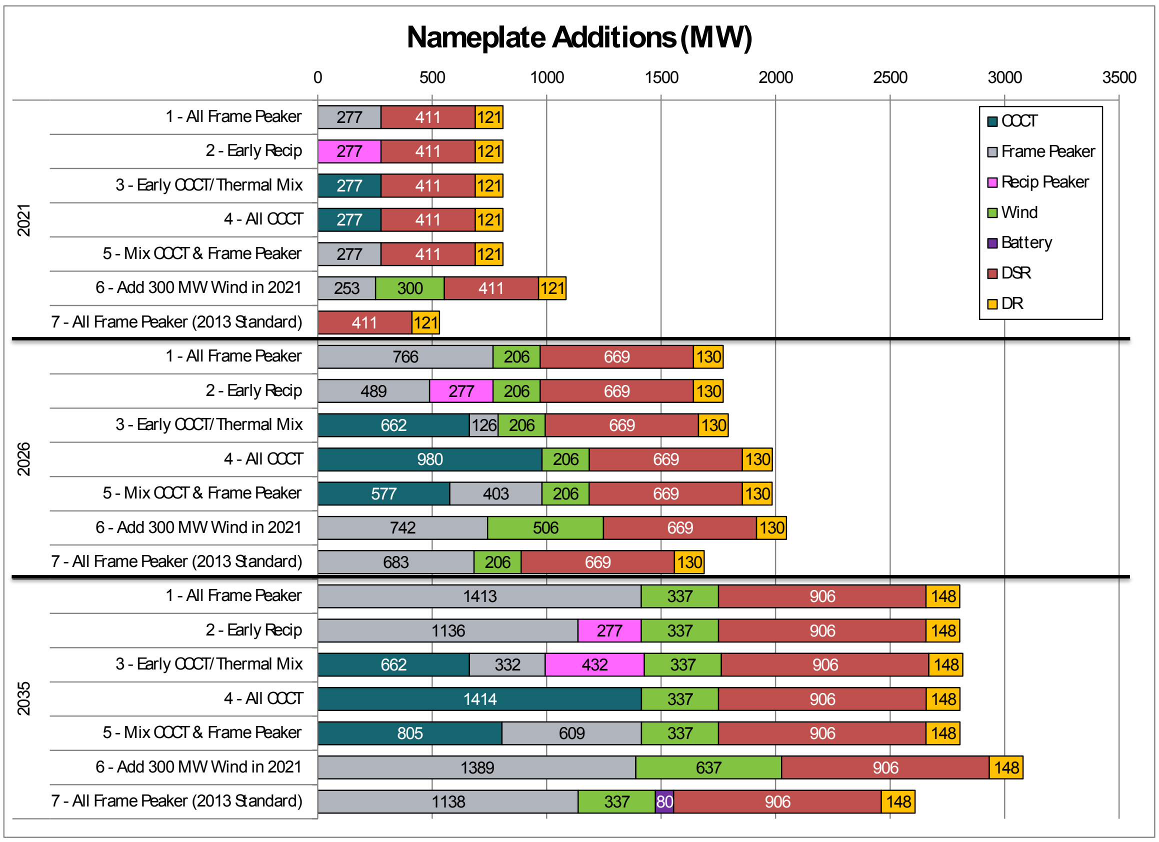
CANDIDATE RESOURCE STRATEGY RESULTS (2015 PLANNING STANDARD)

As part of the 2015 IRP, we developed candidate resource strategies to test different configurations of gas-fired resources and wind.

Summary of Deterministic Analysis

Figure 6-53 below displays the megawatt additions for the deterministic analysis least-cost portfolios for all of the candidate strategies in 2021, 2026 and 2035. See Appendix N, Electric Analysis, for more detailed information.

Figure 6-53: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Summary of Stochastic Analysis

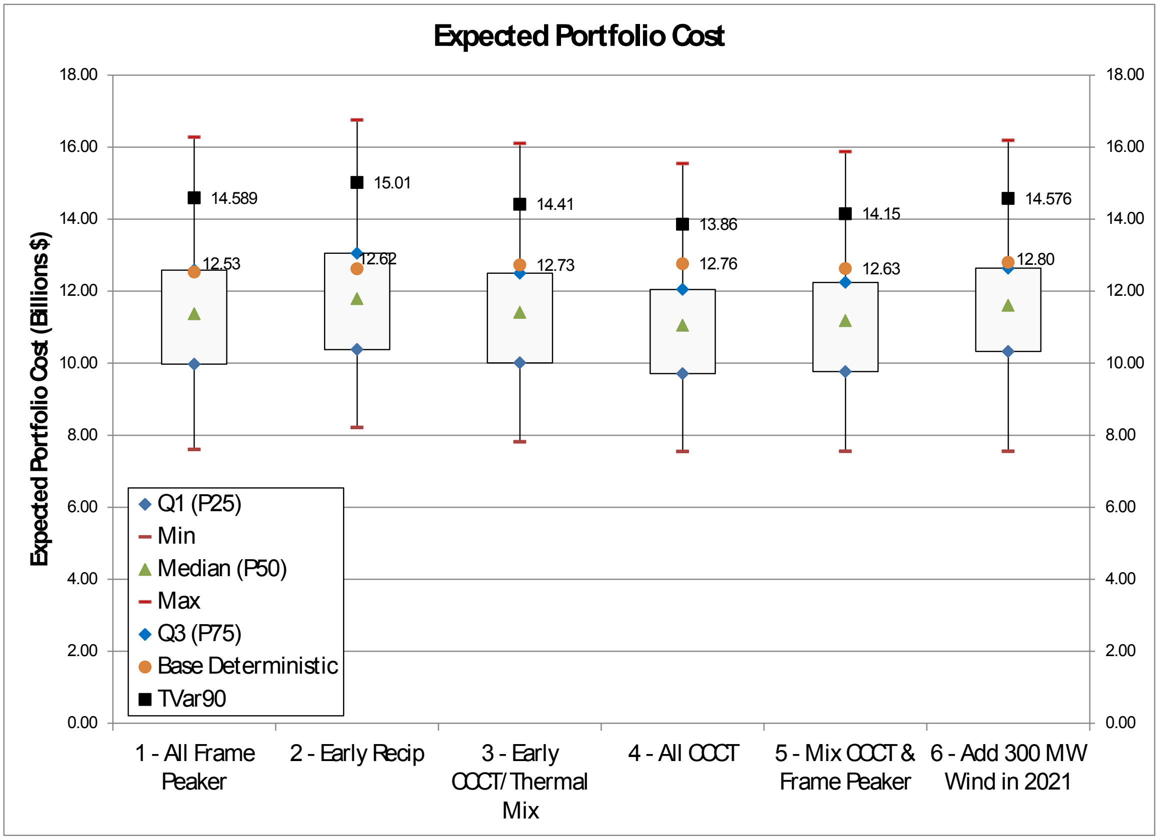
All six candidate portfolio options were tested in the stochastic analysis. In Figure 6-54 below, the all frame peaker is the lowest-cost portfolio in the Base Scenario, but since the stochastic analysis takes into account many different futures we see that the mean of frame peaker portfolio is actually higher cost than the all CCCT and mix of CCCT and frame peaker portfolio.

Figure 6-54: Results of Stochastic Analysis

NPV ($Millions)	Base Deterministic Portfolio Cost	Difference from Base	Mean	Difference from Base	TVar90	Difference from Base
1 - All Frame Peaker	12,531		11,343		14,589	
2 - Early Recip Peaker	12,620	89	11,782	439	15,014	426
3 - Early CCCT/Thermal Mix	12,729	198	11,392	49	14,412	(177)
4 - All CCCT	12,761	230	10,993	(350)	13,856	(733)
5 - Mix CCCT & Frame Peaker	12,627	96	11,138	(205)	14,147	(442)
6 - Add 300 MW Wind in 2021	12,798	267	11,582	239	14,576	(13)

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 a combination of CCCT and frame peakers reduced the cost and risk of the portfolio.

Figure 6-55: Range of Portfolio Costs across 1,000 Trials



GAS-FOR-POWER PORTFOLIO ANALYSIS

Natural gas fuel for power generation is vital to the electric utility's ability to meet customer peak demand reliably. In fact, every IRP since 2007 has identified natural gas-fired generation as the most cost-effective supply-side addition for PSE portfolios. This IRP is no different: All of the electric portfolios produced by the analysis include the addition of substantial amounts of gas-fired generation as part of the solution to meeting future electricity demand.

Determining the resources necessary to ensure that natural gas fuel is available when needed is not a straightforward exercise. Although both CCCTs and peakers are needed to meet peak demand, they require different types of fuel resources. CCCTs are assumed to need 100 percent firm gas transportation since their higher efficiency means they are dispatched more frequently than peakers. Peakers, on the other hand, generally operate with temporary, non-firm pipeline capacity purchased from either the gas sales book, the pipeline, or through the capacity release market, because they are expected to run fewer hours than CCCTs due to their higher, less efficient heat rates.

PSE's owned peakers have dual-fuel capability; that is, they can use either natural gas or distillate fuel (oil) to generate power. Under existing emissions limitations, these plants are allowed to use both forms of fuel. We also have the necessary permits for one additional dual-fuel peaker. Beyond the first additional peaking plant, we assumed the facility would require 50 percent firm gas pipeline transportation. Currently, the future of environmental constraints on CO_2 emissions is uncertain, so it was reasonable to assume new peakers may not receive the permits necessary to generate with oil in all the hours necessary for meeting peak demand. Therefore, peakers beyond the first addition are assumed to be able to generate with distillate fuel oil for some – but not all – of the hours needed to meet peak; hence the addition of 50 percent firm pipeline capacity. We will adjust this expectation according to conditions as they develop in the future.

Gas-for-power Resource Need

Figure 6-56 describes gas-for-power needs for the Base Scenario electric portfolio forecast. This portfolio added 2 new CCCTs, a 577 MW plant in 2026 and a 228 MW plant in 2033; it also added peakers with oil backup in 2021, 2025 and 2030. The peaker added in 2021 is already permitted with the capacity to meet peak winter demand with distillate fuel oil, so additional pipeline capacity isn't needed until the winter of 2026 when the second peaker and first CCCT additions are made. The pipeline capacity requirements shown below include the gas-for-power need for both CCCTs. The green line assumes the peakers added in 2025 and 2030 require 50 percent firm pipeline capacity; the purple line assumes the peakers require no additional firm pipeline capacity because they can use oil for backup fuel. These needs are shown in Figure 6-56.

Figure 6-56: Two Views of Gas-for-power Resource Need
(Existing gas-for-power gas transportation resources compared to peak day demand)

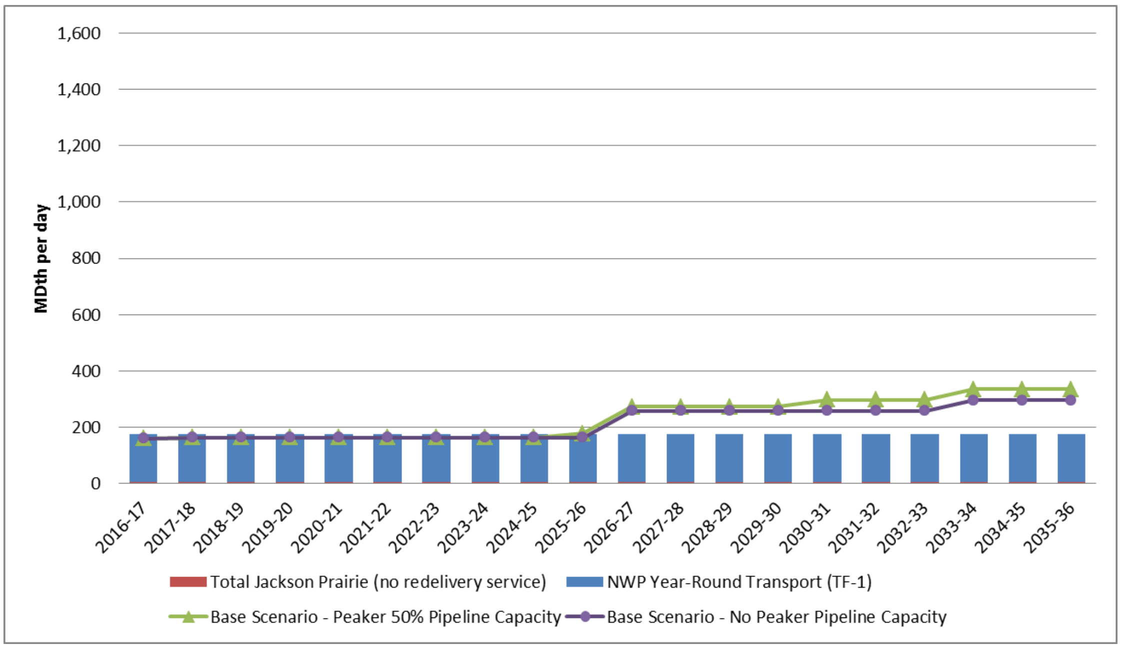


Figure 6-57: Forecast Gas-for-power Pipeline Capacity Need

Forecast Pipeline Need (MDth/day)	2018-19	2026-27	2030-31	2033-34
Peaker 50% Pipeline	11	106	130	167
Peaker No Pipeline	-	91	91	129

Existing Supply-Side Resources

Figure 6-58 summarizes the firm pipeline transportation capacity for delivery of fuel to PSE's gas-fired generation plants.

Figure 6-58: Gas-for-power Generation Gas Pipeline Capacity (Dth/day)

Direct-connect Capacity

Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast (Sumas) to Plant	2017	Yr. to Yr.
Ferndale	Cascade Natural Gas	Firm	(2)	Westcoast (Sumas) to Plant	2037	Yr. to Yr.
Encogen	Cascade Natural Gas	Firm	(2)	NWP (Bellingham) to Plant	2017	Yr. to Yr.
Fredonia	Cascade Natural Gas	Firm	(2)	NWP (Sedro-Woolley) to Plant	2021	Yr. to Yr.
Mint Farm	Cascade Natural Gas	Firm	(2)	NWP (Longview) to Plant (6)	2018	Yr. to Yr.

Upstream Capacity

Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Various	Westcoast	Firm	51,345 (3)	Station 2 to Sumas	2018	Yes
Various	Westcoast	Firm	33,313 (3)	Station 2 to Sumas or Kingsgate	2017	Yes
Various	NWP	Firm	28,928	Stanfield to Bellingham, Jackson Prairie and Deer Island	2025	Assumed (7)
Freddy 1	NWP	Firm	21,747	Westcoast (Sumas) to Plant	2018	Yr. to Yr.
Goldendale	NWP	Firm	45,000	Westcoast (Sumas) to Everett (4)	2018	Yr. to Yr
Various	NWP	Firm	50,000	Stanfield to SIPI	2035	Yes
Various	NWP	Firm	2,000	Sumas to Tacoma	2023	Yes
Various	NWP	Firm	21,747	Westcoast (Sumas) to Plant	2018	Yr. to Yr
Various	NWP	Firm	45,000	Westcoast (Sumas) to Everett (4)	2018	Yr. to Yr
Various	NWP	Firm	10,710	Sumas to Stanfield	2044	Yes
Various	NWP	Firm	500	Sumas to Longview	2044	Yes

Storage Capacity						
Plant	Transporter	Service	Deliverability (Dth/day)	Storage Capacity (Dth)	Year of Expiration	Renewal Right
Jackson Prairie	NWP	Firm	6,704	140,622	2026	Yes
Jackson Prairie (5)	PSE	Firm	50,000	500,000	2016	No

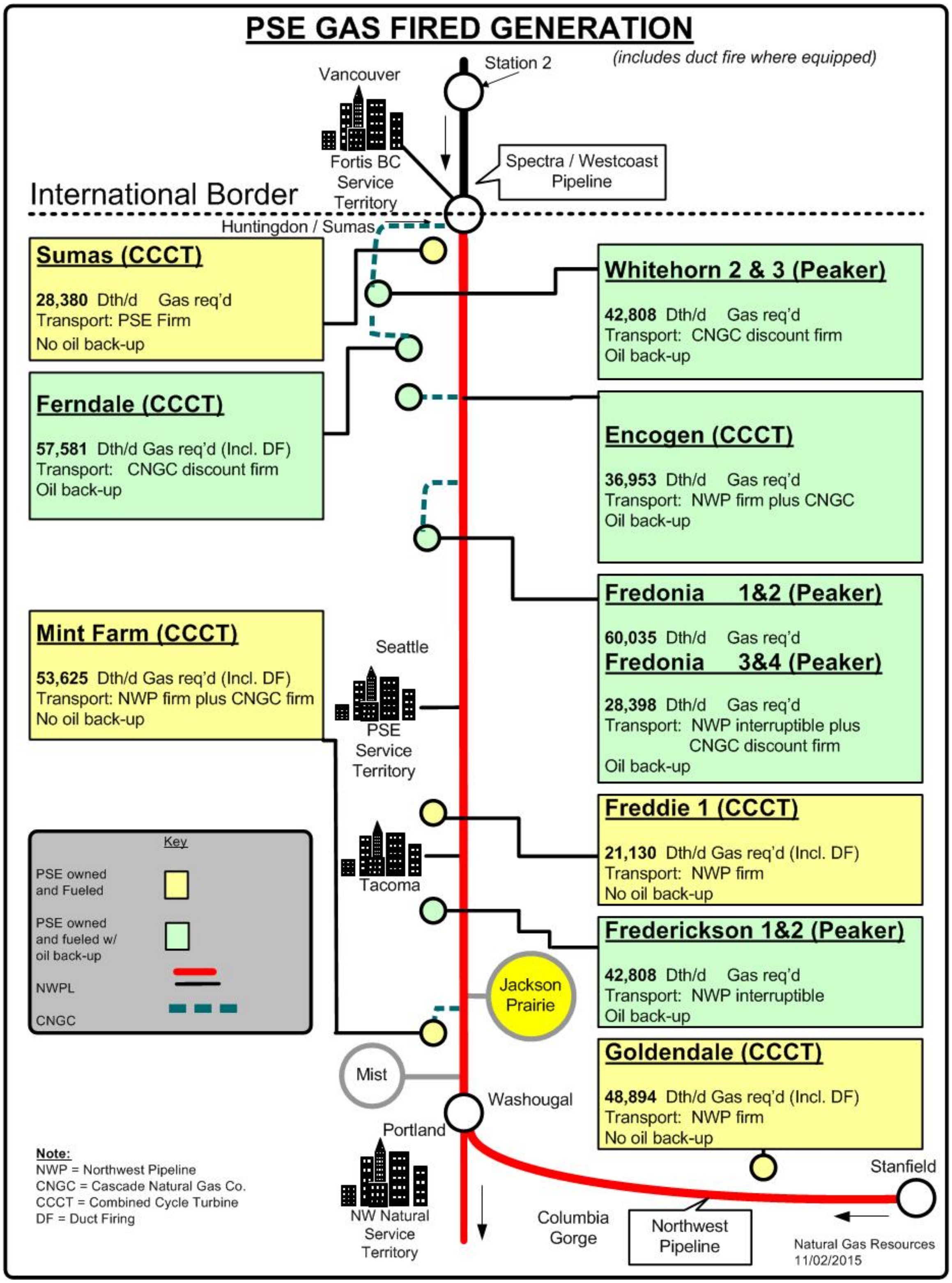
NOTES
1 50% of plant requirements.
2 Full plant requirements.
3 Converted to approximate Dth/day from contract stated in cubic meters/day.
4 Gas transported to points south of Everett under NWP flex rights, when conditions allow..
5 Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. The gas sales portfolio may recall 15,000, 35,000 and 50,000 Dth per day of firm withdrawal rights for up to 4 days in each winter 2013/14, 2014/15 and 2015/16, respectively.
6 30,000 Dth/day is year to year; 22,000 terminates in 2018, but can be renewed.
7 PSE does not have guaranteed renewal rights on this segmented capacity; however, the releasing shipper has indicated willingness to renew the agreement, subject to approval by the pipeline. Renewal may be possible.

PSE has firm NWP pipeline capacity to serve its CCCTs that require NWP service (Encogen, Freddy 1, Goldendale, and Mint Farm); Sumas is directly connected to Westcoast. Ferndale is connected to Sumas via firm capacity on Cascade Natural Gas. All of our simple-cycle combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have fuel oil back-up capability and thus do not require firm pipeline capacity on NWP.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet forecast gas for power generation needs with a mix of long-term (more than two years) and short-term (two years or less) physical gas supply contracts. Longer-term contracts typically supply base-load needs and are delivered at a constant daily rate over the contract period. We estimate average gas for power generation requirements for upcoming months and enter into transactions to balance forecast load. PSE balances daily and intra-day positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE's existing gas-fired generating plants are generally located along the I-5 corridor in western Washington, as the map in Figure 6-59 shows. The exception is Goldendale, which is located near Goldendale, Washington. The peak gas requirement and the type of gas pipeline delivery are also listed. The capacity and operating assumptions for the plants are described in detail in Appendix D, Electric Resources and Alternatives.

Figure 6-59: PSE's Existing Gas-fired Generating Plants



Gas-for-power Resource Alternatives

The complete list of resource alternatives evaluated for the gas-for-power portfolio is detailed in Chapter 7, Gas Analysis. Most relevant to this analysis were the following.

- **CROSS CASCADES TO AECO OR MALIN HUBS**. The prospective Cross Cascades pipeline bringing gas supply from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-AB (NOVA), TC-BC (Foothills) and TC-GTN pipelines to Stanfield; or from the Rockies hub on the Ruby pipeline to Malin (or directly from Malin) and with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline.
- **MIST EXPANSION**. This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland.
- **NWP + WESTCOAST**. Expansion of NWP and Westcoast pipeline to Sumas and Station 2, located in northern BC.

Gas-for-power Analytic Methodology

For this IRP, PSE developed a separate gas portfolio model (SENDOUT) database to evaluate the resource needs of the gas-for-power portfolio. The model inputs include: 1) the costs and capacities for the existing pipeline, storage and gas supply markets as well as for the alternative supply resources, and 2) forecasts of the loads of for existing and future gas-fired plants. The existing and alternative supply resources are described earlier in this chapter and in Chapter 7. The AURORA model develops forecasts of the gas required for the gas-fired plants when performing the analyses of the electric portfolio scenarios; AURORA also dispatches the resources and calculates the electric generation.

While the methodology for the gas-for-power portfolio is very similar to the SENDOUT modeling methodology discussed in Chapter 7, Gas Analysis, the approach to developing gas-for-power needs is different from gas sales loads. In general, gas-fired plants are economically dispatched based on the relationship of the power and gas prices in the market, which is known as the market heat rate. The market heat rate is compared to the plant's heat rate (plus variable dispatch costs) to determine whether it is less expensive to generate power or to purchase it in the market (or sell it into the market when generation is not needed to serve load).

Because electric and gas prices vary based on regional factors such as loads, generation outages, transmission constraints, wind and hydro generation and demand for electricity from adjoining regions, the dispatch of gas-fired plants varies greatly depending on market and weather conditions. The AURORA model incorporates these conditions within the Base Scenario. The daily plant gas use from the AURORA model plus the gas-for-power need calculated during a winter peak event was input to the SENDOUT model to model the Base Scenario's 20-year study period for each of the gas-fired generators. The results are shown in the next section.

Gas-for-power Portfolio Analysis Results

The results discussed in this section are for the electric Base Scenario, which calls for the addition of two CCCTs and three additional gas-fired peakers over the next 20 years, located along the I-5 corridor.

Key Findings. The key findings provide guidance for development of PSE's long-term gas-for-power resource strategy.

1. **Ten MDth per day of the proposed Cross Cascades pipeline providing access to the Stanfield natural gas hub is cost-effective beginning in 2022, filling the gap between existing pipeline capacity to Stanfield and Stanfield supply. Procurement increases in 2026, to 61 MDth per day.**

2. **41 MDth per day of the Mist storage expansion alternative appears cost-effective for the gas-for-power portfolio beginning in 2026.**

3. **The proposed Westcoast to NWP pipeline expansion to access natural gas at the Station 2 hub in British Columbia is a low cost resource choice beginning in 2030.**

Figure 6-60 shows the amount of these resources selected in the electric Base Scenario. The acquisition of the proposed Cross Cascades pipeline capacity, providing access to the Stanfield gas hub is clearly the least-cost resource. Over 80 percent of the Mist storage expansion is chosen as cost effective beginning in 2026. Finally, proposed Westcoast to Northwest pipeline expansion with access to the lower priced Station 2 hub in British Columbia, is a resource choice beginning in 2026.

As discussed earlier and illustrated in Figure 6-58, the gas-fired plants added in the electric Base Scenario are CCCTs, and two of the three additional peakers with oil backup require 50 percent firm pipeline capacity. However, additional gas pipeline capacity may be required to supply the volumes needed to support the combined gas sales and gas-for-power loads and maintain sufficient storage to ensure reliable service.

Figure 6-60: Resource Capacities Selected for the Base Gas-for-power Portfolio (MDth/day)

Base Scenario MDth/day	2018-19	2022-23	2026-27	2030-31	2034-35
Cross Cascades	-	10	64	64	64
Mist Storage Expansion	-	-	41	41	41
NPW/Westcoast Expansion	-	-	-	62	62
Total	**-**	**46**	**105**	**167**	**167**

The electric Base Scenario portfolio adds a 577MW CCCT in 2026 and a 228 MW CCCT in 2033; they require approximately 95,100 and 37,600 Dth per day of natural gas per day, respectively, to run at capacity. Three peakers with a total capacity of 605 MW are added to the portfolio by 2030. As discussed, the first 277 MW peaker is assumed to require no firm pipeline capacity. The second and third peakers add 124 MW in 2025 and 204 MW in 2030 with 50 percent firm pipeline capacity of approximately 14,500 and 23,900 Dth per day, respectively. While the total peak gas need of these CCCT and peaker plants is approximately 275 MDth per day by 2035, after considering a 50 percent pipeline need for the second and third peaker and current gas-for-power transportation contracts, the peak gas-for-power need is 167 MDth per day by 2033.

GAS ANALYSIS

Contents

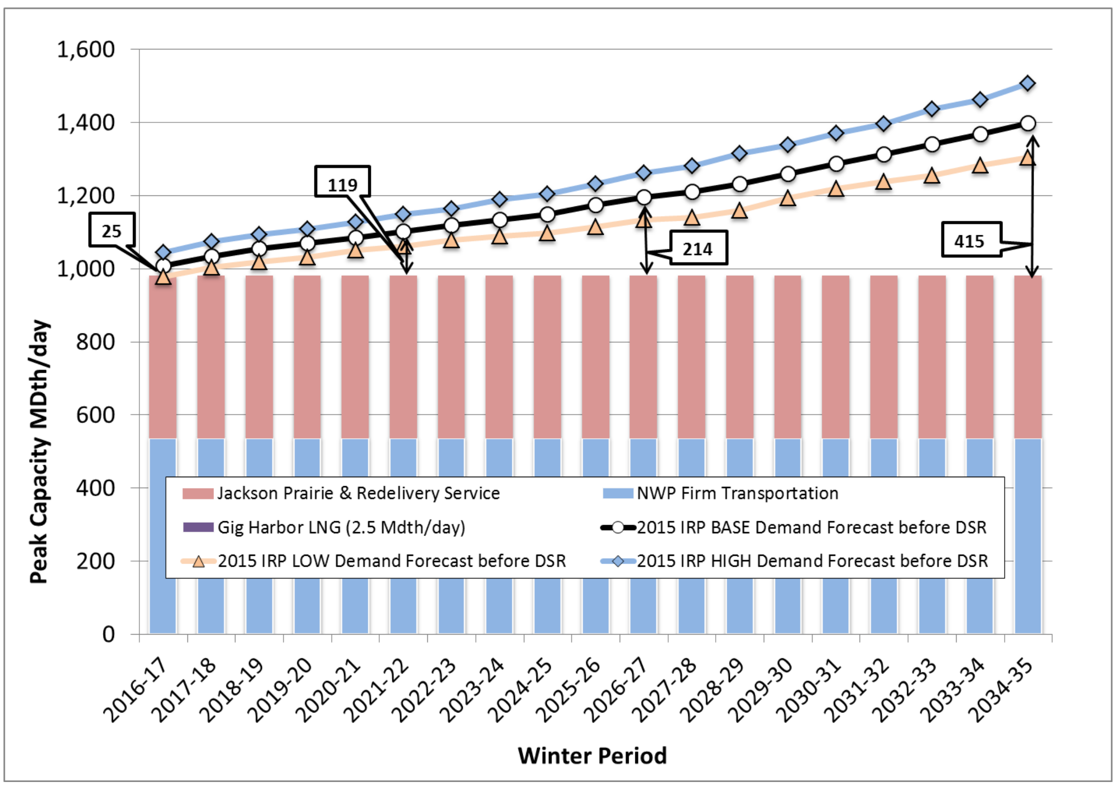
More than 790,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services. The IRP analysis in this chapter enables PSE to develop valuable foresight about how resource decisions to serve our natural gas customers may unfold over the next 20 years in conditions that depict a wide range of futures.

GAS SALES RESOURCE NEED AND KEY ISSUE

Gas Sales Need

Figure 7-1 illustrates gas sales peak resource need over the 20-year planning horizon for the three demand scenarios modeled in this IRP. The lines rising toward the right indicate peak day customer demand before demand-side resources (DSR)[1] and the bars represent existing gas supply resources such as storage facilities, peaking supply resources and contracts for transportation of gas to customers from receipt points at various gas supply locations such as gas supply hubs and storage facilities. The gap between the demand and the existing resources represents the resource need.

Figure 7-1: Gas Sales Peak Resource Need before DSR
Existing Resources Compared to Peak Day Demand
(Meeting need on the coldest day of the year)



1 / *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. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of conservation savings. Therefore the IRP Gas Demand Forecasts include only DSR measures implemented* ***before*** *the study period begins in 2016. These charts and tables are labeled "before DSR."*

PSE's gas sales need is driven by two factors: peak day demand per customer and the number of customers. Our gas sales planning standard is based on peak day demand, which occurs in the winter[2] when temperatures are lowest and heating needs are highest. The heating season and number of lowest-temperature days in the year remain fairly constant and the use per customer is not growing much, if at all, so the growth in customer count is the biggest factor in determining load growth.

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2015 IRP Base Demand Forecast, the 2015 IRP High Demand Forecast, and the 2015 IRP Low Demand Forecast.[3] In the high case, we have a current need for additional firm resources to meet peak day need; in the base demand case, we have sufficient firm resources to meet peak day need until the winter of 2016-17; and in the low demand case, we have sufficient firm resources to meet peak day need until the winter of 2017-18.

Gas Sales Key Issue

Market Reliance on Sumas. Sumas is essentially an interconnection between Westcoast Pipeline (Westcoast) and Northwest Pipeline (NWP). Unlike other market hubs, there is no gas production and no convergence of several pipelines. For years, Westcoast has had surplus capacity, meaning that even on very cold days, there was sufficient infrastructure to bring gas from production areas in Northern British Columbia (B.C.) south to Sumas; PSE did not have to pay in advance for that pipeline capacity. But, as the demand for natural gas to serve gas customer growth and electric generation fuel needs has increased in the Pacific Northwest, less non-firm pipeline capacity is available. Throughput on Westcoast is beginning to hit that pipeline's design planning limit. That means PSE cannot rely on spot market supplies at Sumas to meet our peak loads, but must acquire upstream pipeline capacity on Westcoast to ensure reliable gas supplies will be available to meet our customers' needs. Therefore, in this IRP, we are not considering pipeline capacity on NWP to Sumas alone as a resource; rather, NWP capacity must be coupled with pipeline capacity on Westcoast to be deemed a reliable resource for meeting gas customer peaking needs.

2 / For planning purposes, PSE uses a design peak day demand equivalent to a day with 52 Heating Degree Days (HDDs) or an average temperature of 13° Fahrenheit. HDDs are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD day is calculated as 65° less the 13° temperature for the day.
3 / The 2015 IRP demand forecasts are discussed in detail in Chapter 5, Demand Forecast.

GAS SALES ANALYTIC METHODOLOGY

In general, analysis of the gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing resources. Once need has been identified, a variety of planning tools, optimization analyses and input assumptions help PSE identify the lowest-reasonable-cost portfolio of gas resources in a variety of scenarios.

Optimization Analysis Tools

PSE uses a gas portfolio model (GPM) to model gas resources for long-term planning and long-term gas resource acquisition activities. The current GPM is SENDOUT Version 14.2.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight" – meaning that its theoretical results may not be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them. See Appendix O, Gas Analysis, for a more complete description of the SENDOUT gas portfolio model.

Deterministic Optimization Analysis

As described in Chapter 4, Key Analytical Assumptions, PSE developed 10 scenarios for this IRP. Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

PSE also tested two sensitivities in the gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect a single resource has on the portfolio.

1. How does the timing of pipeline expansions affect resource choices? This sensitivity allows pipeline expansions in every year, versus a baseline of every four years.
2. How does the discount rate affect the amount of cost-effective DSR? This sensitivity applies an alternate discount rate that is lower than PSE's approved weighted average cost of capital (WACC).

Gas portfolio analysis is discussed in more detail in Appendix O, Gas Analysis.

GAS SALES EXISTING SUPPLY-SIDE RESOURCES

Existing gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, gas supplies and demand-side resources.

Existing Pipeline Capacity

There are two types of pipeline capacity. "Direct-connect" pipelines deliver supplies directly to PSE's local distribution system from production areas, storage facilities or interconnections with other pipelines. "Upstream" pipelines deliver gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity. All gas delivered to our gas distribution system is handled last by PSE's only direct-connect pipeline, Northwest Pipeline (NWP). We hold nearly one million dekatherms (Dth) of capacity with NWP.

- 532,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of NWP-Jackson Prairie storage redelivery service

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada; the Rocky Mountain Basin and the San Juan Basin. This provides valuable flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity. To transport gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

A schematic of the gas pipelines for the Pacific Northwest region is provided in Figure 7-2 below. In addition, please see Figure 7-3 for details of PSE's gas sales pipeline capacity.

Figure 7-2: Pacific Northwest Regional Gas Pipeline Map

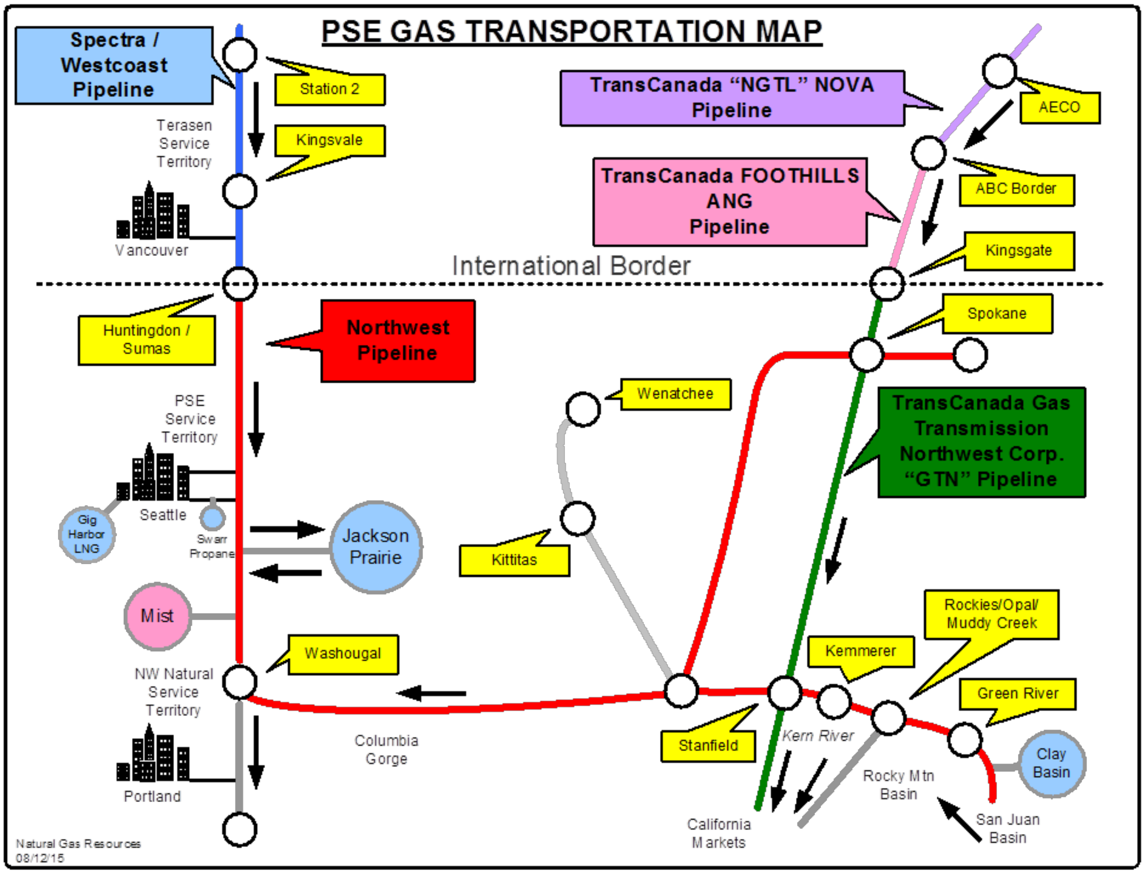


Figure 7-3: Gas Sales Pipeline Capacity (Dth/day)

Pipeline/Receipt Point	N	Total	Year of Expiration 2016	2017-20	2021-35
Direct-connect					
NWP/Westcoast Interconnect (Sumas)	1	269,181	8,386	254,645	6,150
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936	-
NWP/various Rockies	1	187,755	-	187,755	-
Total TF-1		**532,872**	**8,386**	**518,336**	**6,150**
NWP/Jackson Prairie Storage Redelivery Service	1,2	447,057	-	-	447,057
Total Storage Redelivery Service		**447,057**	**-**	**-**	**447,057**
Total Capacity to City Gate		**979,929**	**8,386**	**518,336**	**453,207**

Pipeline/Receipt Point	Note	Total	Year of Expiration 2016	2017-20	2021-35
Upstream Capacity					
NOVA / from AECO to Alberta-BC Border (A-BC Border)	3	79,744	-	79,744	-
Foothills / from Alberta-BC Border to TC-GTN Interconnect (Kingsgate)	4	78,631	70,604	-	8,027
GTN / from Kingsgate to NWP Interconnect (Spokane)	5	65,392	-	-	65,392
TC-GTN / from TC-BC Interconnect (A-BC Border) to NWP Interconnect (Stanfield)	5,6	11,622	-	-	11,622
Westcoast / from Station 2 to NWP Interconnect (Sumas)	4,7	129,855	-	129,855	-
Total Upstream Capacity	**8**	**365,245**	**70,604**	**209,600**	**85,041**

NOTES
1 NWP contracts have automatic annual renewal provisions, but can be canceled upon one year's notice.
2 Storage redelivery service is intended only for delivery of storage volumes during the winter heating season, November through March; these annual costs are significantly lower than year-round TF-1 service.
3 Converted to approximate Dth per day from contract stated in gigajoules per day.
4 Converted to approximate Dth per day from contract stated in cubic meters per day.
5 TCPL-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.
6 Capacity can alternatively be used to deliver additional volumes to Spokane.
7 The Westcoast contracts contain a right of first refusal upon expiration.
8 Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

Transportation Types

TF-1. TF-1 transportation contracts are "firm" contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport gas every day.

Storage Redelivery Service. PSE holds TF-2 and winter-only discounted TF-1 capacity under various contracts to provide for firm delivery of Jackson Prairie storage withdrawals. These services are restricted to the winter months of November through March and provide for firm receipt only at Jackson Prairie; therefore, the rates on these contracts are substantially lower than regular TF-1 transportation contracts.

Firm versus Non-firm Transportation Capacity. Firm transportation capacity carries the right, but generally not the obligation (subject to operational flow orders from a pipeline), to transport up to a maximum daily quantity of gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported.

Non-firm service is subordinate to the rights of shippers who hold and use firm transportation capacity, hence it is "interruptible." The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Non-firm capacity on a fully contracted pipeline results from a firm shipper not fully utilizing its firm rights on a given day. This unused (aka: interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport gas outside of their firm transportation path.

PSE may release capacity when it has a surplus of firm capacity and when market conditions make such transactions favorable for customers. The company also uses the capacity release market to access additional firm capacity when it is available. Interruptible service plays a limited role in PSE's resource portfolio because it cannot be relied on to meet peak demand.

Existing Storage Resources

PSE's natural gas storage capacity is a significant component of the company's gas sales resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers. Benefits include the following.

- Ready access to an immediate and controllable source of firm gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store additional gas during the lower-demand summer season, generally at lower prices.
- Combining storage capacity with storage redelivery service transportation allows us to contract for less year-round pipeline capacity to meet winter-only demand.
- PSE also uses storage to balance city gate gas receipts with the actual loads of our gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie storage, in Lewis County, Wash. is an aquifer-driven storage field designed to deliver large quantities of gas over a relatively short period of time. Clay Basin, in northeastern Utah, provides supply-area storage and a winter gas supply. Figure 7-4 presents details about storage capacity.

Figure 7-4: Gas Sales Storage Resources[1]

Facility	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Expiration Date
Jackson Prairie – Owned	8,528,000	156,000	398,667	N/A
Jackson Prairie – NWP SGS-2F[3]	1,359,481	21,313	54,467	2016
Subtotal Jackson Prairie – Available	9,887,481	177,313	453,134	
Jackson Prairie – Owned[2]	(500,000)	(25,000)	(50,000)	2016
Jackson Prairie – NWP SGS-2F[4]	(178,460)	(2,378)	(6,077)	2020
Net Jackson Prairie	9,209,021	149,935	397,057	*Note 7*
Clay Basin[5]	12,882,750	53,678	107,356	2018/20
Clay Basin[6]	(4,000,000)	(37,011)	(74,023)	2018
Net Clay Basin	8,882,750	16,667	33,333	
Total Gas Sales Storage Resources	**18,091,771**		**430,390**	

NOTES
1 Storage, injection, and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.
2 Storage capacity made available to PSE's power portfolio (at market-based prices) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs.
3 NWP contracts have automatic annual renewal provisions, but can be canceled upon one year's notice.
4 Released to Cascade Natural Gas through 4/1/2020, subject to recall.
5 PSE expects to renew the Clay Basin storage agreements.
6 Assigned to third parties through 4/1/2018.
7 Total withdrawal capacity is 447,057 Dth/day if the 50,000 Dth/day is retained.

Jackson Prairie Storage. PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project (Jackson Prairie), which is operated by PSE under FERC authorization. As shown in Figure 7-3, PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. In addition to firm daily deliverability and firm seasonal capacity, PSE has access to deliverability and seasonal capacity through contracts for SGS-2F storage service from NWP. The NWP contracts are automatically renewed each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core gas customers – that is, to meet seasonal load requirements, balance daily load and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

Clay Basin Storage. Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service. As shown in Figure 7-4, 4,000,000 Dth of this storage capacity has been assigned to third parties through March 2018.

PSE uses Clay Basin for certain levels of baseload supply, and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (and other markets) using firm NWP TF-1 transportation.

Treatment of Storage Cost. Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. PSE also pays a variable charge for gas injected into and withdrawn from Clay Basin. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through a purchased gas adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. The Gig Harbor liquefied natural gas (LNG) satellite storage and the Swarr vaporized propane-air (LP-Air) facility provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these resources typically help to meet extreme peak demand during the coldest hours or days. These resources do not offer the flexibility of other supply sources.

Figure 7-5: Gas Sales Peaking Resources

Facility	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Transport Tariff
Gig Harbor LNG	10,500	2,500	2,500	On-system
Swarr LP-Air[2]	128,440[2]	16,680[1,2]	0[2]	On-system
Total	**138,940**	**19,180**	**2,500**	

NOTES
1 Swarr holds 1.24 million gallons. At a refill rate of 111 gallons per minute, it takes 7.7 days to refill, or 16,680 Dth per day.
2 Swarr upgrade is anticipated to be complete for winter 2016-2017 operations.

Gig Harbor LNG. Located in the Gig Harbor area of Washington state, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's distribution system. The Gig Harbor plant receives, stores and vaporizes LNG that has been liquefied at other LNG facilities. It represents an incremental supply source and its 2.5 MDth per day capacity is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-AIR. The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary work necessary to upgrade the facility's environmental safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP (see Combination #7 – Swarr), and is assumed to be available for the 2016-2017 winter, beginning November 2016. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Existing Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and changed the picture with regard to gas supplies. Not only has development of shale beds in British Columbia, Canada directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages. This separation cycle can last several years, but should be alleviated when additional pipeline infrastructure is constructed. PSE expects generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation and forecast demand increase.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal and Clay Basin; but alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TransCanada's TC-AB Nova pipeline and TransCanada's TC-BC Foothills pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. PSE meets average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Long-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. PSE also contracts for seasonal baseload firm supply, typically for the winter months November through March. Near-term transactions supplement baseload transactions, particularly for the winter months; PSE estimates average load requirements for upcoming months and enter into month-long transactions to balance load. PSE balances daily positions using storage from Jackson Prairie and Clay Basin, day-ahead purchases and off-system sales transactions, and balances intra-day positions using Jackson Prairie. PSE continuously monitors gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE's customer demand is highly weather dependent and therefore seasonal in nature. PSE's general policy is to maintain longer-term firm supply commitments equal to approximately 50 percent of expected seasonal demand, including assumed storage injections in summer and net of assumed storage withdrawals in winter; that percentage grows as we move closer to the delivery month and day.

Existing Demand-side Resources

PSE has provided demand-side resources since 1993.[4] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[5] Through 1998, the programs primarily served residential and low-income customers; in 1999 the company expanded them to include commercial and industrial customer facilities. Figure 7-8 shows that energy efficiency measures installed through 2014 have saved a cumulative total of nearly 4.9 million Dth – more than half of which has been achieved since 2007.

PSE spent almost $12 million for natural gas conservation programs in 2014 compared to $3.2 million in 2005. Spending over that period increased more than 25 percent annually and more recently there has been a shift downwards as gas prices have come down and fewer measures qualify as cost-effective savings. This shift, however, is not sustainable. PSE is engaged in collaborative regional efforts to find creative ways to make delivery and marketing of gas efficiency programs more cost-effective and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

PSE's energy efficiency programs serve residential, low-income, commercial and industrial customers. Energy savings targets and the programs to achieve those targets are established every two years. The 2012-2013 biennial program period concluded at the end of 2013; current programs operate January 1, 2014 through December 31, 2015. The majority of gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

For the 2014-2015 period, PSE has a two-year target of approximately 694,060 Dth in energy savings. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group.

4 / Demand-side resources are resources that are generated on the customer (demand) side of the meter.
5 / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 7-6: Gas Sales Energy Efficiency Program Summary, 2012 – 2015
Total Savings and Costs

Sector	2012-2013 Actual Total Savings (Therms)	2012-2013 Actual Total Costs ($)	2014-2015 Target Total Savings (Therms)	2014-2015 Budget Total Costs ($)	Percent Change in Savings (%)	Percent Change in Costs (%)
Residential	3,355,000	$12,586,000	4,020,600	$14,575,300	20%	16%
Commercial /Industrial	8,388,000	$10,986,000	2,920,000	$7,472,200	-65%	-32%
Total	11,743,000	$23,572,000	6,940,600	$22,047,500	-41%	-6%

Figure 7-7: Natural Gas Program Costs and Savings Trends

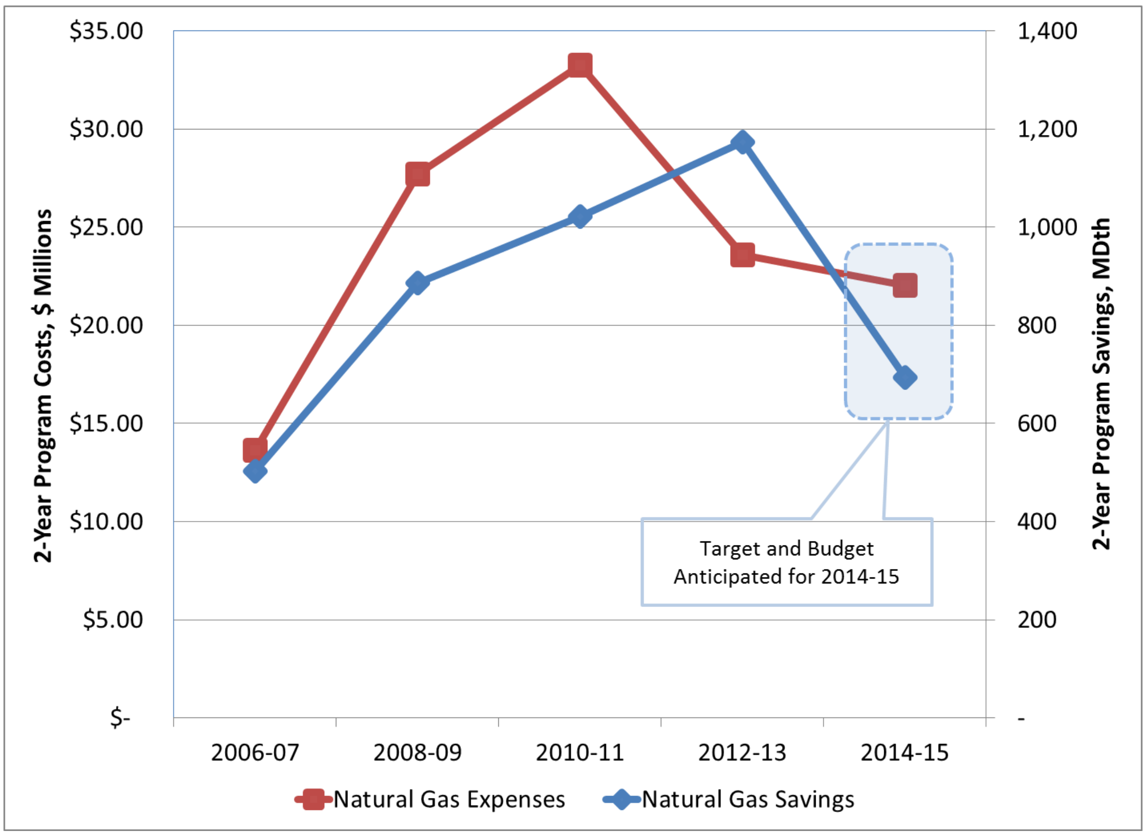
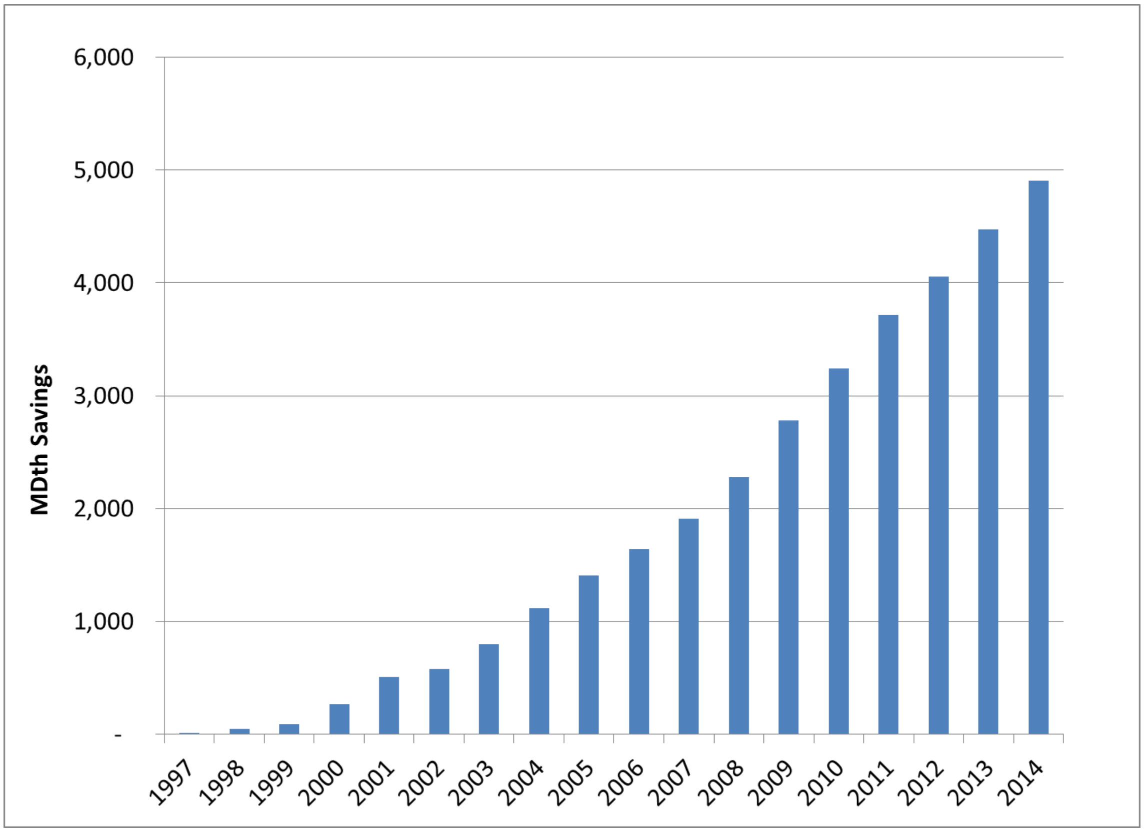


Figure 7-8: Cumulative Gas Sales Energy Savings from DSR, 1997 – 2014



GAS SALES RESOURCE ALTERNATIVES

The gas sales resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

Transporting gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analyses. These combinations are discussed below and illustrated in Figure 7-9. Note that DSR is a separate alternative discussed later in this chapter.

Combination #1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning October 2018, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE seeks to hold Westcoast capacity equivalent to 100 percent of NWP firm take-away capacity at Sumas. This upstream capacity strategy has increased from 50 percent in the 2013 IRP due to the regional decline of available non-firm pipeline capacity.

COMBINATION #1A – NWP-TF-1

This is a short-term pipeline alternative that represents excess capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from October 2016 through September 2018 only. Beyond September 2018, other long-term resources would be added to serve demand.

Combination #2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Spectra with an estimate that it is available beginning October 2018. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of AECO gas to PSE via existing or expanded capacity on the TC-AB and TC-BC pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

Combination #3 – Cross-Cascades - AECO

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-AB (NOVA), TC-BC (Foothills) and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline.

Combination # 4 – Cross-Cascades - Malin

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come directly from Malin or from the Rockies hub on the Ruby pipeline to Malin, with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline.

Combination #5 – PSE LNG Project

This combination entails construction of an LNG peak-shaving facility to serve the needs of core gas customers as well as regional LNG fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project achieves economies of scale that reduce costs for core gas customers. This project would be located at the Port of Tacoma and connect to PSE's existing distribution system. The analysis assumes the project is put into service for the 2018-19 heating season, providing 69 MDth per day of capacity. The full 85 MDth per day capacity will be available with additional upgrades to the gas distribution system, which are estimated to be in service for the 2020-21 heating season.

Combination #6 – Mist

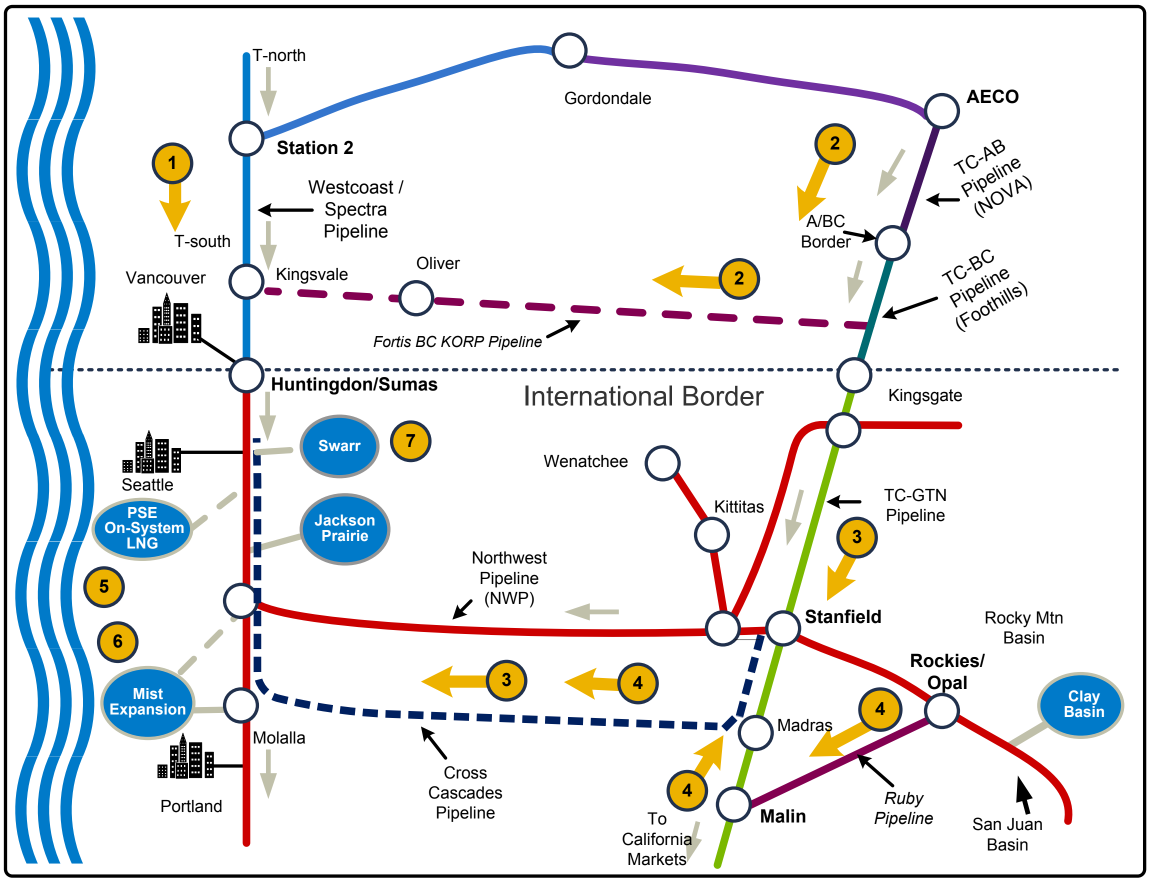
This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland.

Combination #7 – Swarr

This is an upgrade to the existing Swarr LP-air facility as discussed above. This upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network.

A schematic of the gas sales resource alternatives is depicted in Figure 7-9 below.

Figure 7-9: PSE Gas Transportation Map Showing Supply Alternatives



Baseload Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives. The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 7-10 below.

Figure 7-10: Direct-connect Pipeline Alternatives Analyzed

Direct-connect Pipeline Alternatives	Description
NWP - Sumas to PSE city gate *(from Combinations 1 & 2)*	Expansions considered either independently (from 2016 to 2018), or in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available October 2018.
Cross Cascades – Stanfield/TC-GTN to PSE city gate *(from Combinations 3 & 4)*	Representative of costs and capacity of the proposed Cross Cascades pipeline with delivery on NWP to PSE city gate. Assumed to be available by 2018.

Upstream Pipeline Capacity Alternatives. In some cases, a tradeoff exists between buying gas at one point and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast Energy's BC Pipeline (Westcoast), which allows PSE to purchase gas at Station 2 rather than Sumas and take advantage of greater supply availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase gas directly from suppliers at the very liquid AECO trading hub and transport it to interconnect with the proposed Cross Cascades pipeline on a firm basis. FortisBC and Spectra have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO supplies.

Figure 7-11: Upstream Pipeline Alternatives Analyzed

Upstream Pipeline Alternatives	Description
Increase Westcoast Capacity (Station 2 to PSE) *(from Combination 1)*	Acquisition of currently uncontracted Westcoast capacity is considered to increase access to gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Stanfield) *(from Combinations 2 & 3)*	Acquisition of currently uncontracted capacity of TransCanada pipeline capacity in Canada (TC-AB & TC-BC) and on TC-GTN in the U.S., to increase deliveries of AECO gas to Stanfield for delivery to PSE city gate via the proposed Cross Cascades pipeline.
Kingsvale-Oliver Reinforcement Project (KORP) *(from Combination 2)*	Expansion of the existing FortisBC Southern Crossing pipeline across southern B.C., enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of uncontracted capacity on the TC-AB and TC-BC pipelines.
GTN Backhaul from Malin to Stanfield (Malin to Stanfield) *(from Combination 4)*	Acquisition of GTN Backhaul capacity from Malin to Stanfield to provide access to Malin hub and connect over proposed Cross Cascades pipeline to PSE.

The KORP alternative includes PSE participation in an expansion of the existing FortisBC pipeline across southern British Columbia which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-AB and TC-BC lines, would improve access to the AECO trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.

Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie storage facility, and PSE also contracts for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run. For this IRP, the company considered the following storage alternatives.

PSE LNG Project. PSE is developing a small-scale LNG liquefaction and storage facility within its service territory to serve the peaking needs of PSE's core gas customers and the growing demand for LNG as a marine and vehicle transportation fuel. The economies of scale afforded by a combined-use facility may make this a cost-effective resource for gas customers.

The peaking component of the PSE LNG Project would utilize gas purchased by the PSE gas sales portfolio throughout the year, transported over NWP and PSE distribution system to the plant, where it would be liquefied and stored. Under peak demand conditions, up to 66,000 Dth per day of PSE's 538,039 Dth share of stored LNG would be vaporized and injected back into the PSE gas distribution system to meet customer demand. In addition, under peak demand conditions, up to 19,000 Dth per day of natural gas flowing on NWP to serve the daily liquefaction requirements of LNG transportation fuel customers could be diverted to other PSE gas distribution system interconnects to serve PSE customers. The diverted gas volumes would be replaced with PSE-owned LNG already in storage to keep the LNG transportation fuel customers whole. As configured, the PSE LNG Project would provide a peaking resource of up to 85,000 Dth per day to PSE gas sales customers for the equivalent of approximately 6 days per year. For analysis purposes, the facility is assumed to enter service for the 2018-19 heating season, with 69,000 Dth per day peaking service (providing an 8-day supply), and the full 85,000 Dth per day peaking capacity (providing a 6-day supply) is assumed available at the start of the 2020-21 winter season.

Mist Expansion. NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., is investigating a potential expansion project to be completed in 2016-2017. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2018, once Mist is built. This would also require expansion of NWP's interstate system to PSE's city gate. PSE may be able to acquire discounted winter only capacity from Mist to PSE's city gate if NWP expands from Sumas to Portland for other shippers, however, that has not been modeled due to the unknown timeline for that potential project.

Swarr. The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated as PSE is in the preliminary stages of upgrading Swarr's environmental safety and reliability systems and increasing production capacity to 30,000 Dth per day. The facility is assumed to be available for the 2016-2017 heating season.

Figure 7-12: Storage Alternatives Analyzed

Storage Alternatives	Description
PSE LNG Project *(Combination 5)*	These analyses assume an 8-day supply at full deliverability of 69 MDth/day beginning the 2018-19 heating season (50 MDth/day out of the LNG plant and 19 MDth/day of diverted gas deliverable to points across the PSE system). Beginning the 2020-21 heating season, additional upgrades to the PSE distribution system will allow the LNG plant to inject 66 Dth/day, increasing the total project capacity to 85 MDth/day, which is a net 6.3-day supply.
Expansion of Mist Storage Facility *(Combination 6)*	Based on estimated cost and operational characteristics of expanded Mist storage. Assumes a 20-day supply at full deliverability.
Swarr LP-Air Facility Upgrade *(Combination 7)*	This upgrade would increase the peak day planning capability from 10 MDth/day to 30 MDth/day.

Gas Supply Alternatives

As described earlier, gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate gas supplies will be available to support pipeline expansion from northern British Columbia or from the Rockies basin.

Additional cost and capacity data for all of the supply-side resource alternatives is presented in Appendix O, Gas Analysis.

Demand-side Resource Alternatives

To develop demand-side alternatives for use in the portfolio analysis, PSE first conducts a conservation potential assessment. This study reviews existing and projected building stock and end-use technology saturations to estimate the savings possible through installation of more efficient commercially available technologies. The broadest measure of savings from making these installations (or replacing old technology) is called the technical potential; this represents the total unconstrained savings that could be achieved without considering economic (cost-effectiveness) or market constraints.

The next level of savings is called *achievable* technical potential. This step reduces the unconstrained savings to levels considered achievable when accounting for market barriers. The achievability factors developed in previous IRPs have not changed: 75 percent are considered achievable. The measures are then organized into a conservation supply curve, from lowest to highest levelized cost.

Next, individual measures on the supply curve are grouped into cost segments called "bundles." For example, all measures that have a levelized cost of between $2.2 per Dth and $3.0 per Dth may be grouped into a bundle and labeled "Bundle A1." The Code and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that have been passed but that take effect at a future date. This bundle is always selected in the portfolio, where it effectively represents a reduction in the load forecast.

Figure 7-13 shows the two price bundles that were developed for this IRP. One uses the weighted average cost of capital (WACC) assigned to PSE and the other uses the alternate discount rate developed for the discount rate sensitivity analysis.

PSE currently seeks to acquire as much cost-effective gas demand-side resources as quickly as possible. The acquisition or "ramp rate" of gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures are assumed to be acquired in the first 10 years; this is called a 10-year ramp rate. Acquiring these measures sooner rather than later has been tested in prior IRPs and has consistently been found to reduce portfolio costs. Ten years is chosen because it aligns with the amount of savings that can practically be acquired at the program implementation level.

Figure 7-13: DSR Cost Bundles and Savings Volumes for 10-Year Ramp Rate

		Using WACC		Using Alternate Discount Rate	
Bundle	**Price Cut-Offs for Bundles**	**2025 MDth 10-Yr**	**2035 MDth 20-Yr**	**2025 MDth 10-Yr**	**2035 MDth 20-Yr**
Codes & Standards	**$0**	**2,016**	**2,797**	**2,016**	**2,797**
A	< $2.20/Dth	1,235	1,677	1,778	2,781
A1	$2.2 to $3.0	1,761	2,737	1,889	2,966
A2	$3.0 to $4.5	1,886	2,950	2,047	3,411
B	$4.5 to $5.5	2,011	3,337	2,267	3,800
B1	$5.5 to $7.0	2,236	3,729	2,534	4,208
C	$7.0 to $8.5	2,422	4,050	2,891	4,743
C1	$8.5 to $9.5	2,667	4,432	3,612	6,269
D	$9.5 to $12.0	3,218	5,316	5,374	8,319
E	$12.0 to $15.0	3,872	6,734	6,018	9,365
F	$15.0 to $20.0	6,022	9,390	7,972	13,186
G	>= $20	14,001	21,476	14,001	21,476

More detail on the measures, assumptions and methodology used to develop DSR potentials can be found in Appendix J, Demand-side Resources.

In the final step, the gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 7-14 illustrates the methodology described above.

Figure 7-14: General Methodology for Assessing Demand-side Resource Potential

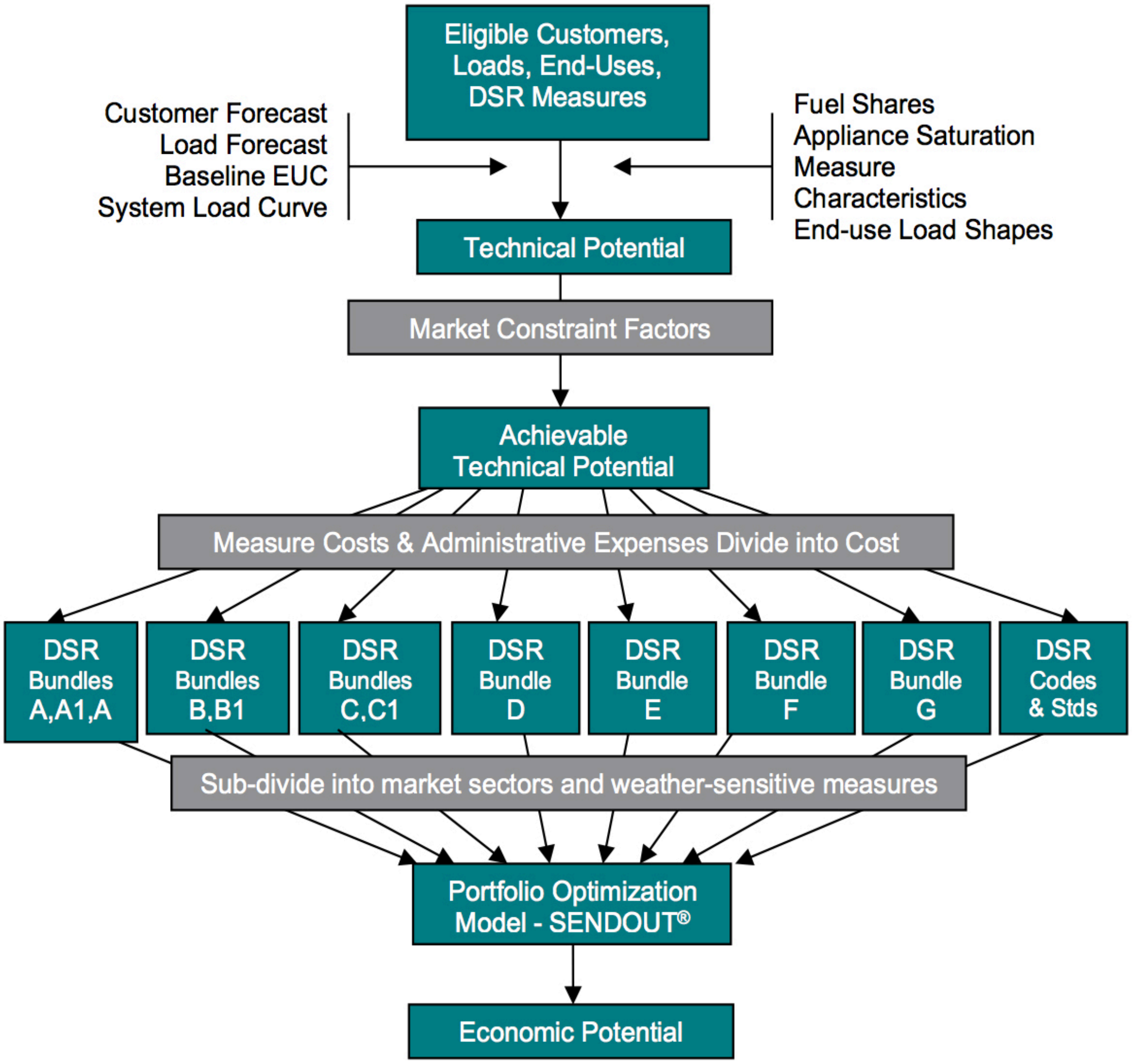


Figure 7-15 shows the range of achievable technical potential among the eleven cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side gas resource for a particular scenario.

Figure 7-15: Demand-side Resources – Achievable Technical Potential Bundles

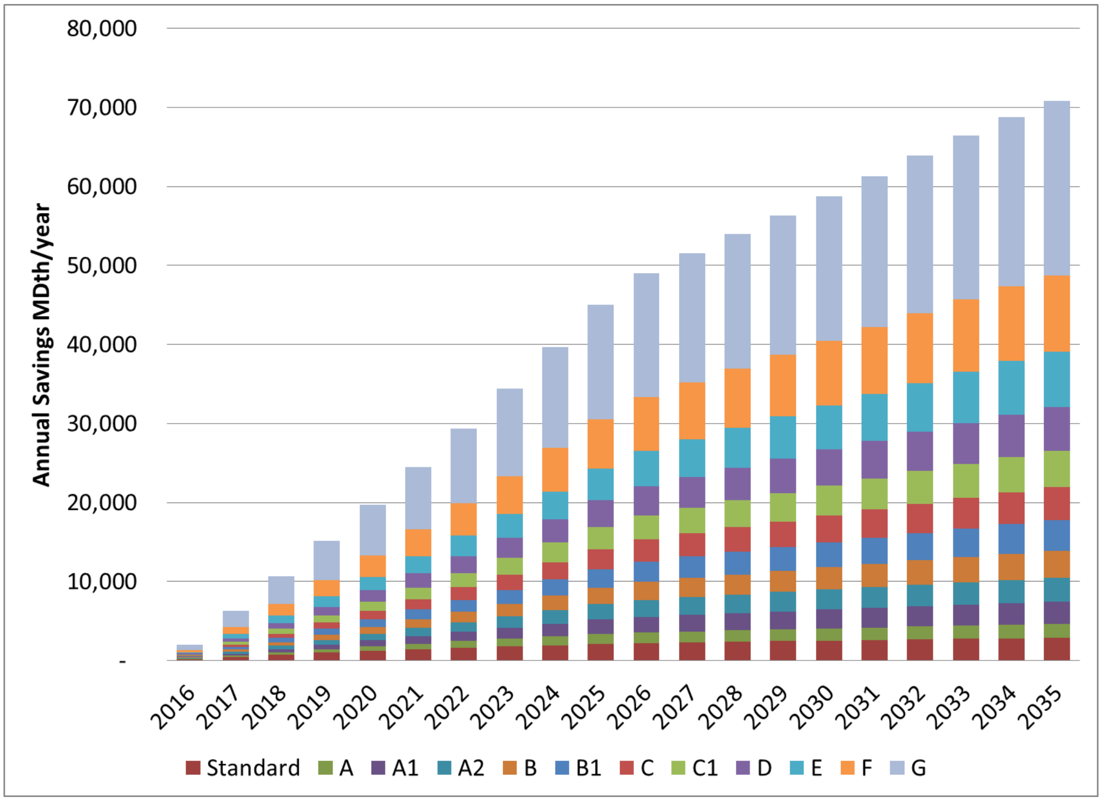
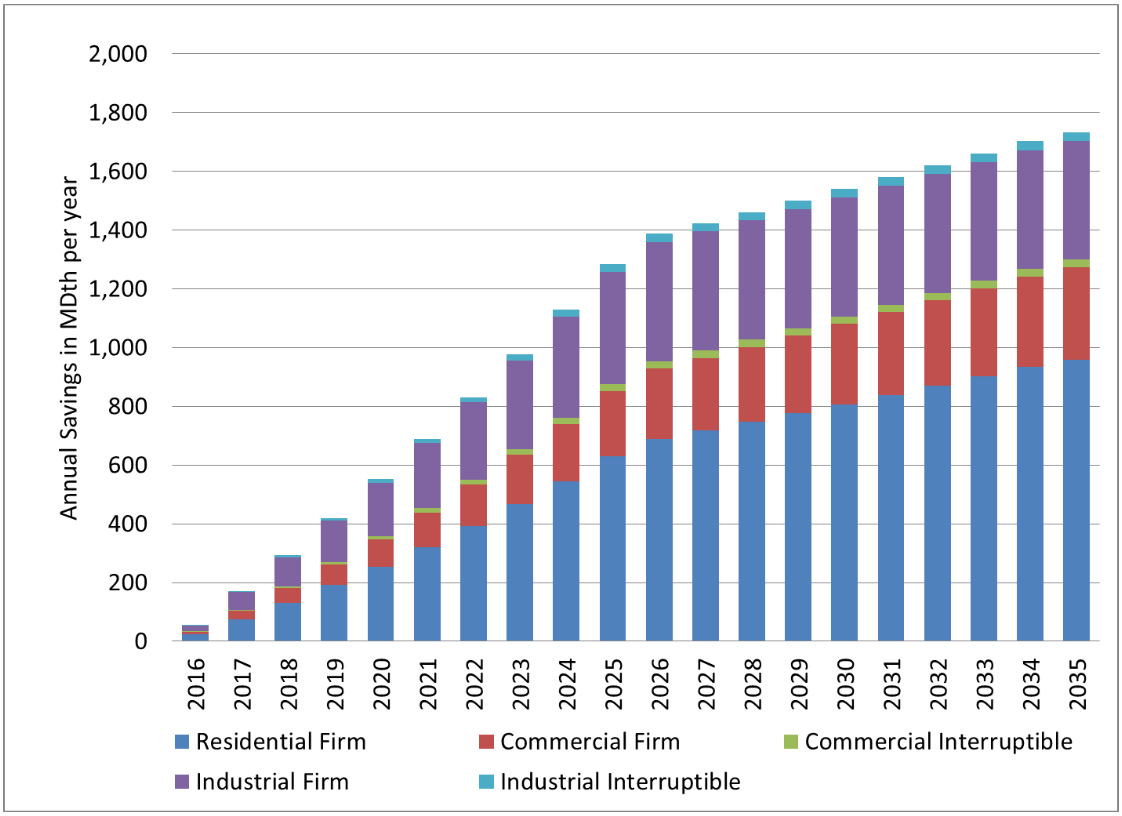


Figure 7-16 shows a sample input format subdivided by customer class for Bundle A (<$2.20 per Dth) used in the GPM for all the IRP scenarios.

Figure 7-16: Savings Formatted for Portfolio Model Input
by Customer Class – Bundle A (< $2.20/Dth)



GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical and statistical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

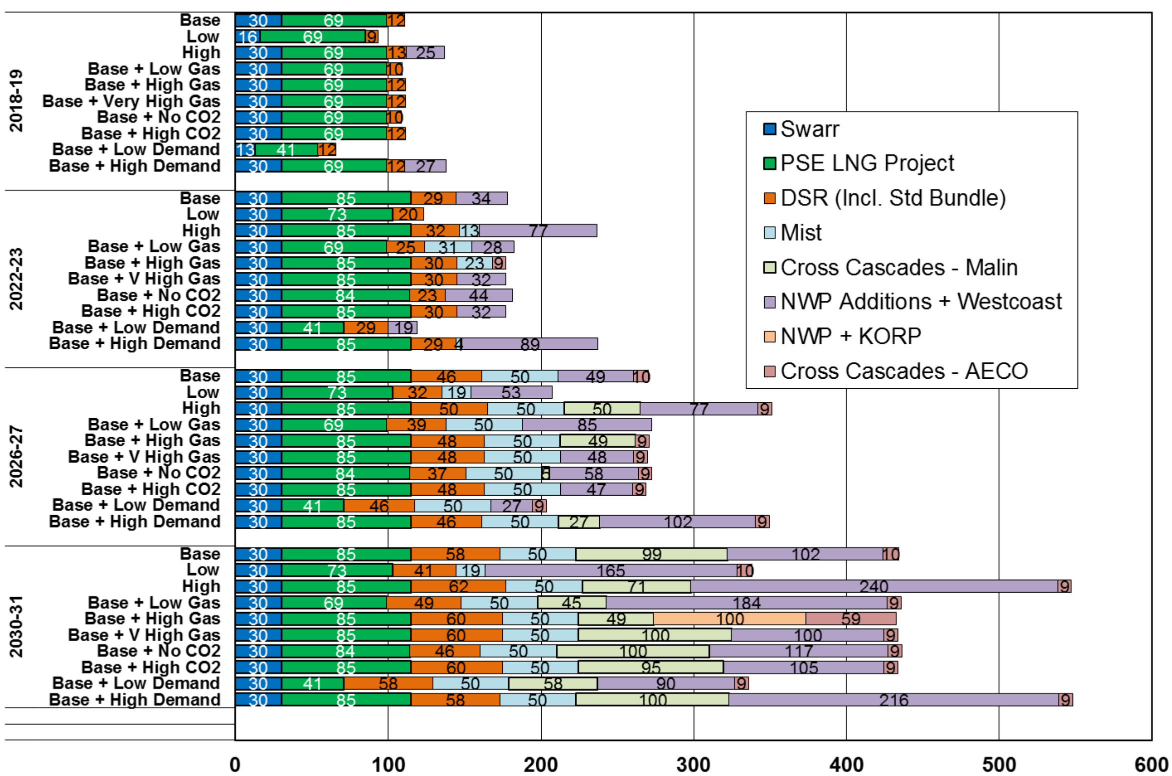
1. **In the Base Scenario, the gas sales portfolio is short resources in the winter of 2016-17.** The High Demand Scenario shows a current resource shortfall in the gas sales portfolio, while the Low Demand Scenario is short in the winter of 2017-18.
2. **Immediate short-term need will be met with combination of three resources in all scenarios:** demand-side resources, a 2016-2018 short-term contract for excess pipeline capacity from Sumas to PSE and the Swarr upgrade project.
3. **Cost-effective DSR is lower in the 2015 IRP** due to past program achievements, updated end-use energy consumption model assumptions, and new standards and codes that resulted in some DSR being shifted out of utility-program DSR bundles and into the standards and codes bundle**.**
4. **The PSE LNG Project is cost-effective in all scenarios.** As currently envisioned, this project would have a total peaking capacity of 69 MDth per day available for service for the 2018-19 heating season. After additional distribution upgrades, it would reach its full peaking capacity of 85,000 Dth per day starting the winter of 2021-22. The timing of the capacity increase can be adjusted to meet customer needs.
5. **The Swarr upgrade project is cost-effective in all scenarios** and is expected to provide 30 MDth per day of peaking capacity effective November of 2016-17.
6. **The Mist storage expansion is selected in most scenarios starting in 2026-27.** While this resource is selected in most scenarios, its feasibility is dependent on expansion of NWP from Sumas to Portland.
7. **Increased Westcoast capacity to Station 2 is the favored pipeline alternative in most scenarios.** The pipeline alternative to purchase gas at Malin and deliver it to PSE's city gate via the TC-GTN pipeline across the proposed Cross Cascades pipeline is chosen in most scenarios by winter 2030-31. While this is true, the GPM indicates acquisition of additional pipeline capacity on Westcoast to access gas from Station 2 is more cost effective as early as 2018-19 in some scenarios and by 2022-23 in most scenarios.

Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature; however, the absolute level of efficiency programs is also affected by load growth assumptions. Also, the timing of pipeline additions was limited to four-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the ten scenarios[6] are illustrated in Figure 7-17 for winter periods 2018-19, 2022-23 and 2030-31. Combination #2, FortisBC/Westcoast (KORP), was chosen in only one of the scenarios – in 2030-31 in the Base + High Gas scenario.

Figure 7-17: Gas Resource Additions in 2018-19, 2022-23, 2026-27 and 2030-31 (Peak Capacity – MDth/day)

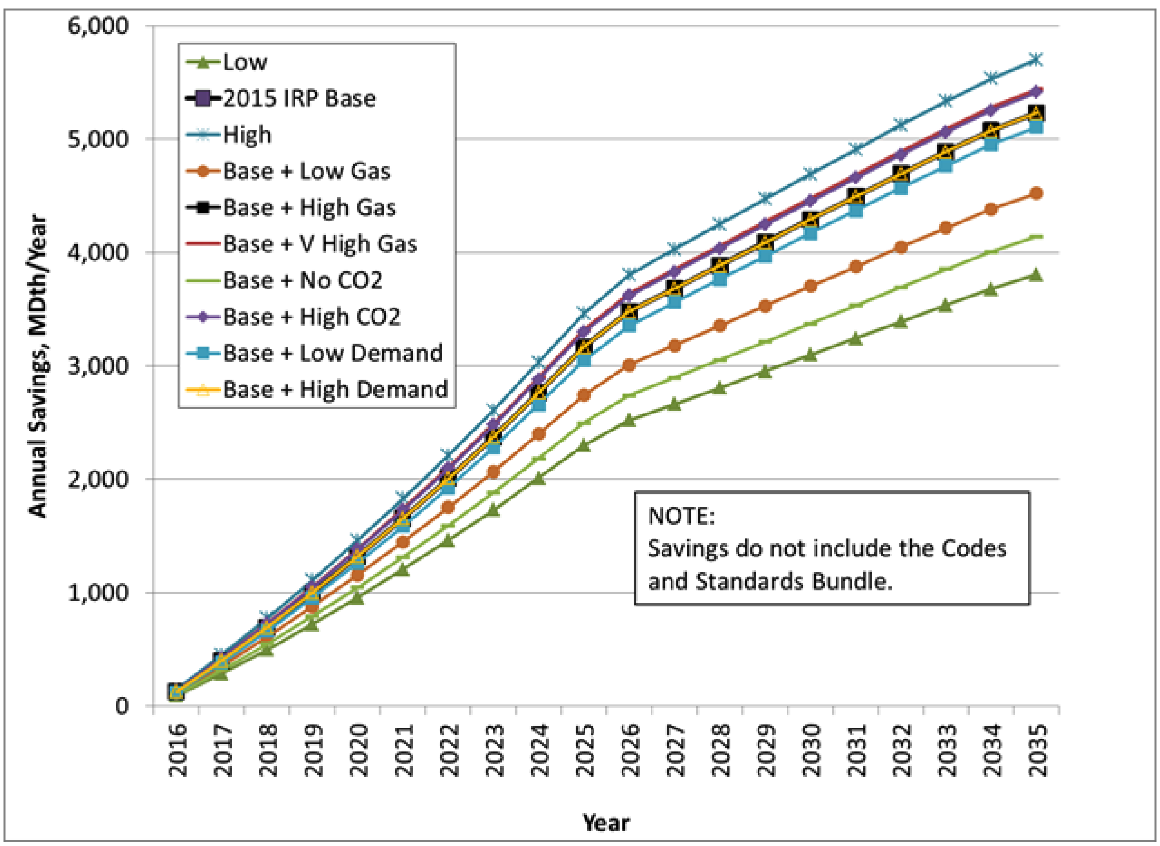


6 / *Scenarios are explained in detail Chapter 4, Key Analytical Assumptions.*

Demand-side Resource Additions. Two categories of demand-side resources are input in to the GPM: codes and standards and program measures. Codes and standards is a no-cost bundle that becomes a must-take resource; it essentially functions as a decrement to gas demand. Program measures are input as separate cost bundles along the demand-side resource supply curve. The bundles are tested from lowest to highest cost along the supply curve until the system cost is minimized. The incremental bundle that raises the portfolio cost is considered the inflexion point, and the prior cost bundle is determined to be the cost-effective level of demand-side resources.

Carbon costs do impact the amount of cost-effective DSR. For example, the above Figure 7-18 illustrates that in the Base Scenario, which includes a CO_2 price, cost-effective DSR is 12 MDth per day by 2018/19, whereas in the Base Scenario without CO_2 price, the DSR level falls to 10 MDth per day. In terms of gas supply planning, 2 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the 2015 IRP Base Scenario increases conservation by approximately 20 percent in 2018-19.

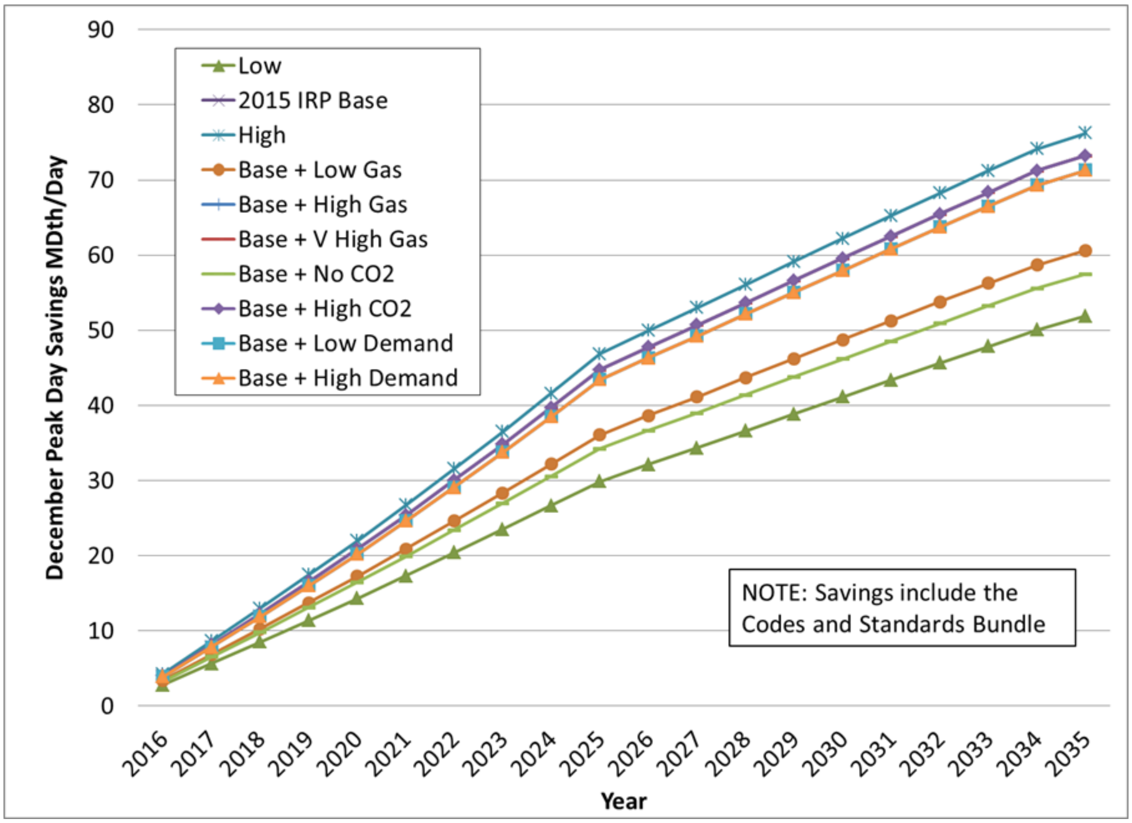
Figure 7-18: Cost-effective Gas Energy Efficiency Savings by Scenario



DSR remains relatively sensitive to avoided costs in the gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this plan ranged from roughly 3,800 MDth in 2035 for the Low Scenario to nearly 50 percent higher at 5,700 MDth in 2035 in the High Scenario.

Peak savings by scenario are shown in Figure 7-19.

Figure 7-19: Cost-Effective Gas Efficiency, Peak Day Savings by Scenario



The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 7-20 and 7-21, below. More detail on this analysis is presented in Appendix J, Demand-side Resources Analysis.

Figure 7-20: Gas Sales Cost-effective DSR Bundles by Class and Scenario

Bundles	Low	2015 IRP Base	High	Base + Low Gas	Base + High Gas	Base + V High Gas	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
Residential Firm	B1	C1	D	C1	D	D	C1	D	C1	C1
Commercial Firm	B1	D	E	C1	D	D	C	D	D	D
Commercial Interruptible	A1	A2	B1	A2	B	B1	A2	B	A2	A2
Industrial Firm	A2	A2	A2	A2	A2	A2	A2	A2	A2	A2
Industrial Interruptible	A2	A2	A2	A2	A2	A2	A2	A2	A2	A2

Figure 7-21: Gas Sales Cost-effective Annual Savings by Class and Scenario

Bundles, Savings in 20th Year (MDth/Year)	Low	2015 IRP Base	High	Base + Low Gas	Base + High Gas	Base + V High Gas	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
Residential Firm	2,119	2,363	2,538	2,363	2,538	2,538	2,363	2,538	2,363	2,363
Commercial Firm	1,183	2,348	2,608	1,641	2,348	2,348	1,383	2,348	2,348	2,348
Commercial Interruptible	45	60	96	60	68	96	60	68	60	60
Industrial Firm	427	427	427	427	427	427	427	427	427	427
Industrial Interruptible	32	32	32	32	32	32	32	32	32	32
Total Savings	3,806	5,230	5,701	4,524	5,413	5,441	4,266	5,413	5,230	5,230

Overall, the economic potential of DSR in this IRP is lower than in the 2013 gas sales Base Scenario, even though higher-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 7-22 below).

The downward shift in the overall savings is due to several factors:

- Past program accomplishments have lowered future achievable potentials.
- New, higher Department of Energy efficiency standards for some gas appliances have moved some potentials from utility program bundles to the standards and codes bundles.
- Building stock data has been updated using the Residential Building Stock Assessment.
- Models to simulate energy use and savings have been updated.

On the other hand, inclusion of CO_2 costs in the Base Scenario tended to increase conservation targets, because it made the overall levelized cost of gas in the 2015 IRP Base Scenario higher than the 2013 IRP Base Scenario. For more information on how gas sales DSR differs in the 2015 IRP vs. the 2013 IRP, see Appendix J, Demand-side Resources Analysis.

Figure 7-22: Cost-effective Gas Energy Efficiency Savings, 2013 IRP vs 2015 IRP

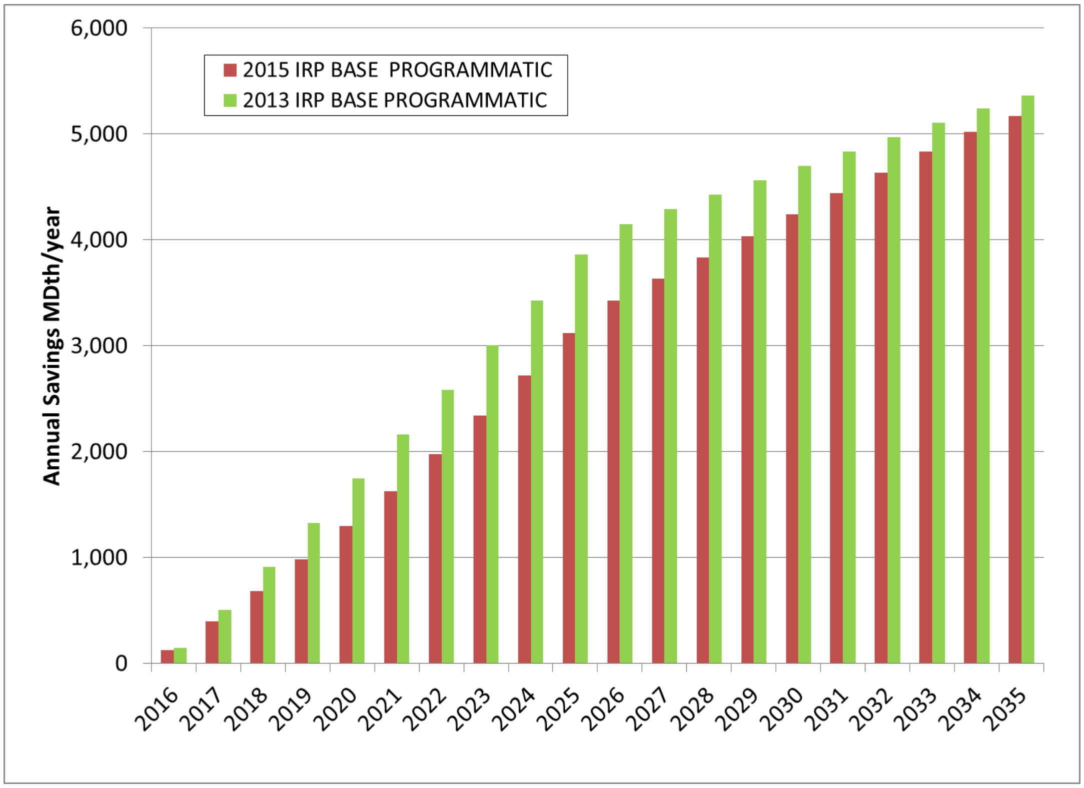


Figure 7-23 below compares PSE's energy efficiency accomplishments, current targets and the new range of gas efficiency potentials as determined by the analysis. In the short term, the 2015 IRP indicates an economic potential savings of 397 to 618 MDth for the 2016-2017 period.[7] The 694 MDth target for the current 2014-2015 period is higher than this range. These two-year program accomplishments and projections show a downward trend, for the reasons discussed above.

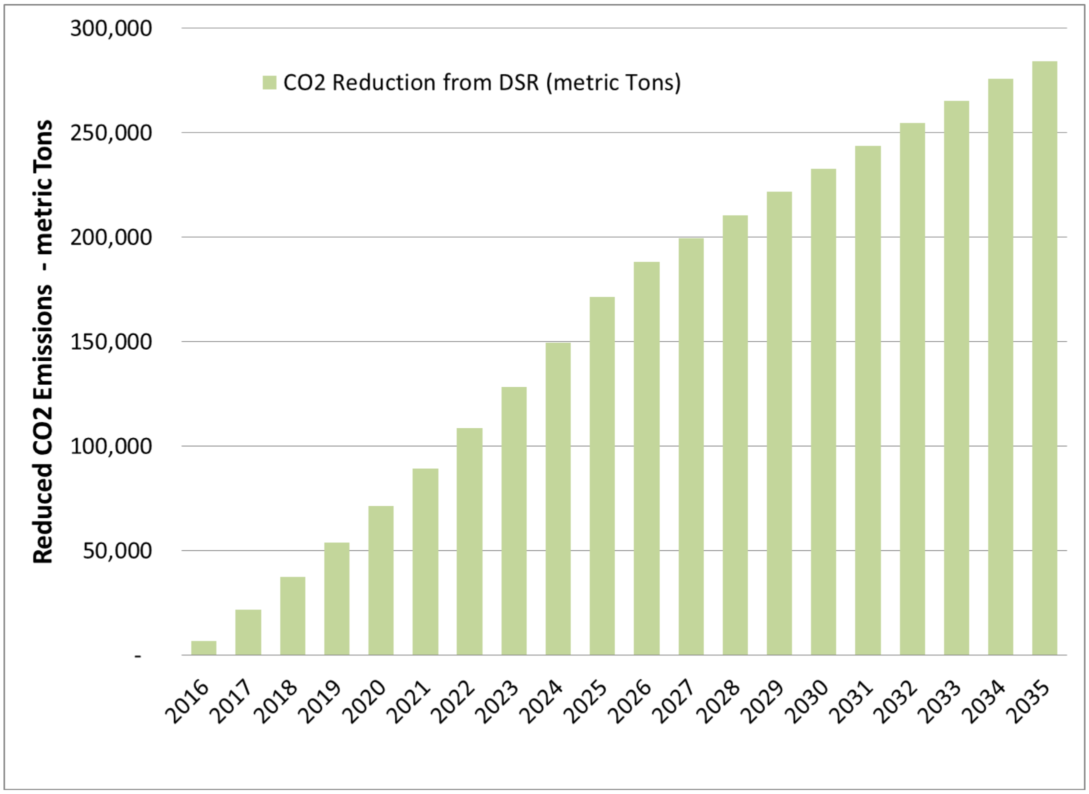
Figure 7-23: Short-term Comparison of Gas Energy Efficiency in MDth

Short-term Comparison of Gas Energy Efficiency	Dth over 2-year program
2012-2013 Actual Achievement	1,174
2014-2015 Target (Updated Jan 2015)	694
2016-2017 Range of Economic Potential	397 – 618

7 | These savings are based on a no-intra year ramping, which are used to set conservation program targets.

Figure 7-24 below shows the impact on CO_2 emissions from energy efficiency measures selected in the Base Scenario.

Figure 7-24: CO_2 Emissions Reduction from Energy Efficiency in Base Scenario



Pipeline Additions. Pipeline expansion alternatives were made available as early as the 2018-19 winter-season, the same time that the other non-pipeline alternatives were made available. Though this timeline is too short for any realistic pipeline expansion, it allowed PSE to ensure that the other resources were selected on their own merits as a least-cost resource. A short-term, firm pipeline contract was also included as an alternative. That contract would transport gas from Sumas to PSE as a bridge contract from October 2016 through September 2018.

The Sumas to PSE 2016-2018 short-term contract was selected in most scenarios. Based on lower costs, most scenarios chose some of the NWP expansion and Westcoast pipeline to purchase gas from Station 2 as cost effective in 2022-23, increasing these capacities in subsequent years. The expansion of the Northwest and Westcoast pipelines from Station 2 increases access to northern B.C. gas supplies. Other pipeline additions were not cost effective till 2026-27 in most scenarios, but the Cross Cascades - Malin which sources gas from Malin through Stanfield across the proposed Cross Cascades pipeline was included in most scenarios by 2030-31. The NWP + KORP pipeline alternative was more expensive and chosen only in the Base + High Gas Scenario. Additional upstream pipeline capacity from AECO on the TC-AB, the TC-BC, and GTN pipelines was selected in minor amounts to deliver supplies to the proposed Cross Cascades pipeline.

Storage Additions. Based on lower costs, the PSE LNG Project and the Mist storage expansion were selected in all scenarios.

PSE LNG Project. PSE is in the early stages of developing a small-scale natural gas liquefaction and LNG storage facility within its service territory to serve the peaking needs of PSE's core gas customers and the growing demand for LNG as a marine and vehicle transportation fuel. The PSE LNG Project was found to be cost effective in every scenario, as shown in Figure 7-17, above. Figure 7-25 focuses on just the PSE LNG Project additions by scenario. It shows that in most scenarios and sensitivities, all 85 MDth per day of LNG[8] is part of the least cost plan forecast. However, it also illustrates that in four of the scenarios, less than the full 85 MDth per day would be optimal given the modeling constraints of the GPM. The optimization routine in the SENDOUT GPM doesn't optimize on all or nothing choices; it simply cannot decide whether it is best to either acquire a fixed capacity resource or not – rather, the model is designed to help answer optimal sizing questions.

8 / As noted above, the analyses assume that 69 MDth per day will be available for the 2018-19 heating season and 85 MDth per day will be available for the 2020-21 heating season.

In these types of all-or-nothing resource decisions, the GPM is a good first screen, but additional analysis is needed when considering resources with fixed capacity. PSE can, however, use the SENDOUT GPM to help analyze the all-or-nothing question by comparing two cases: one where the fixed capacity resource is not an alternative and another where 100 percent of the fixed capacity resource is included. This is the analysis PSE performed for the PSE LNG Project; Figure 7-26 compares the net present value of the portfolio in which the PSE LNG Project is not a choice with a portfolio which includes all 85 MDth per day. Figure 7-26 shows there are portfolio benefits (aka: cost savings) of including the PSE LNG Project as a resource in every scenario. This IRP confirms the PSE LNG Project to be a least-cost resource to serve customer demand.

Figure 7-25: PSE LNG Project Resource Additions by Scenario (MDth per day)

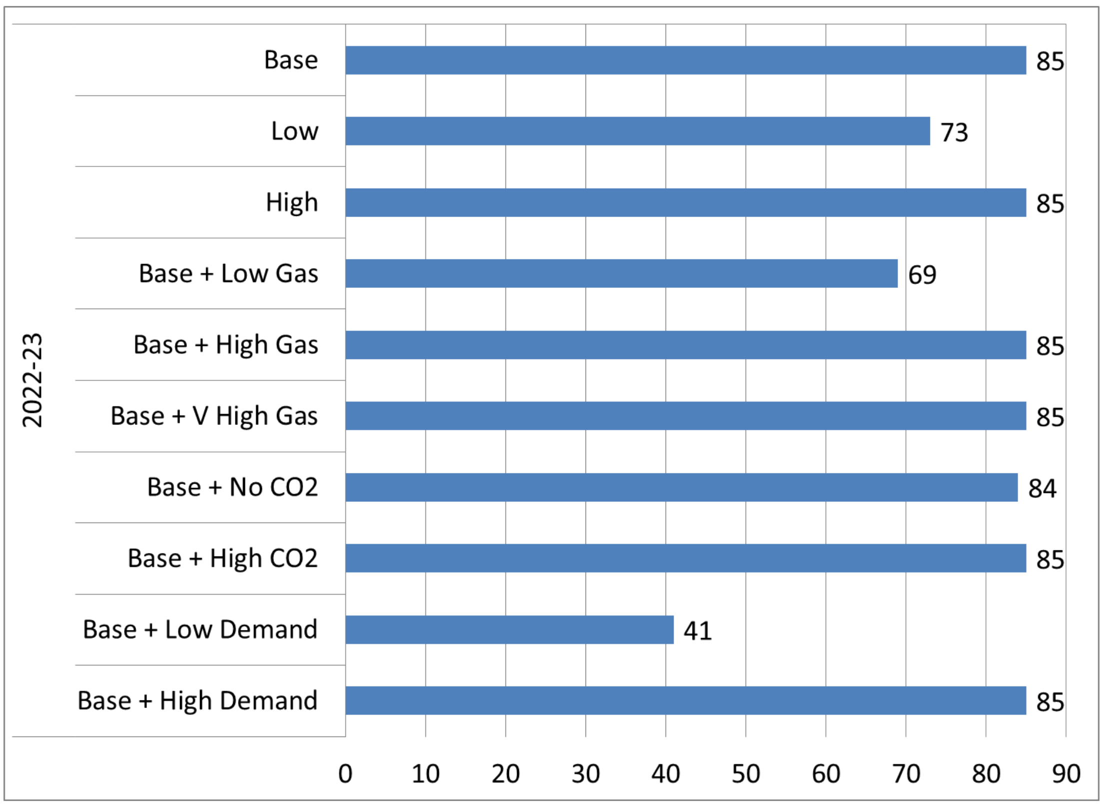


Figure 7-26: Scenario Portfolio Benefit of the PSE LNG Project

	Gas Portfolio Costs Net Present Value ($000s)		
SCENARIO	**FULL LNG**	**NO LNG**	**(Benefit) / Cost of LNG**
BASE	$ 9,366,925	$ 9,464,726	$ (97,801)
LOW	$ 6,257,998	$ 6,294,659	$ (36,661)
HIGH	$ 12,963,307	$ 13,052,452	$ (89,146)
BASE + LOW GAS	$ 8,212,622	$ 8,263,903	$ (51,281)
BASE + HIGH GAS	$ 10,719,839	$ 10,823,632	$ (103,794)
BASE+VERY HIGH GAS	$ 11,906,047	$ 11,994,805	$ (88,758)
BASE+NO CO2	$ 7,775,728	$ 7,846,172	$ (70,444)
BASE+HIGH CO2	$ 10,465,655	$ 10,565,404	$ (99,748)
BASE+LOW DEMAND	$ 9,031,721	$ 9,040,101	$ (8,379)
BASE+HIGH DEMAND	$ 10,450,532	$ 10,550,911	$ (100,379)

Mist Storage Expansion. The Mist storage expansion is selected in most scenarios starting in 2026-27. This result means that PSE will continue to consider pursuing storage capacity at Mist, keeping in mind that Mist expansion is dependent on expansion of NWP from Sumas to the Portland area.

Supply Additions. The Swarr LP-Air upgrade project was selected as least-cost in every scenario.

Complete Picture: Gas Sales Base Scenario

A complete picture of the Gas Sales Base Scenario optimal resource portfolio is presented in graphical and table format in Figures 7-27 and 7-28, respectively. Note that Combination #2, FortisBC/Westcoast (KORP), was not chosen in any of the years. Again, additional scenario results are included in Appendix O, Gas Analysis.

Figure 7-27: Gas Sales Base Scenario Resource Portfolio

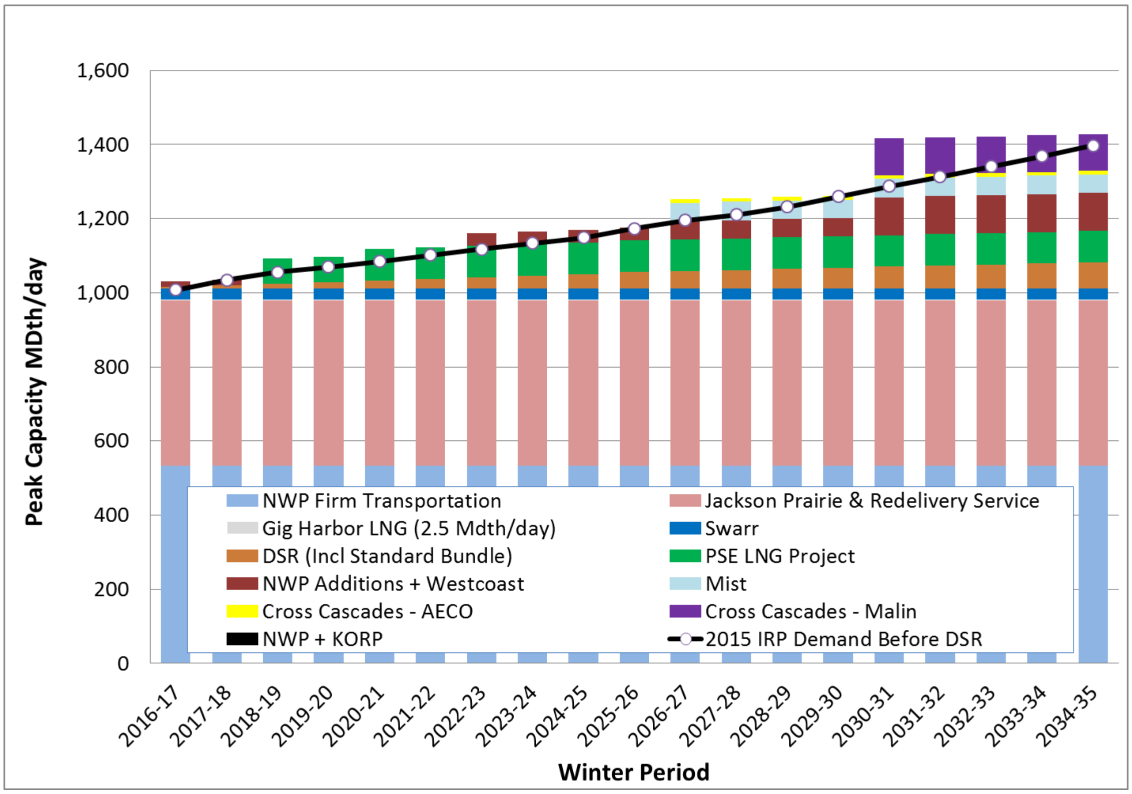


Figure 7-28: Gas Sales Base Scenario Resource Portfolio (table)

Base Scenario MDth/day	2018-19	2022-23	2026-27	2030-31	2034-35
Demand-side Resources	12	29	46	58	69
PSE LNG Project	69	85	85	85	85
Swarr Upgrade	30	30	30	30	30
NWP/Westcoast Expansion	-	34	49	102	102
Mist Storage Expansion	-	-	50	50	50
Cross Cascades to AECO Expansion	-	-	10	10	10
Cross Cascades to Malin Expansion	-	-	-	99	99
Total	111	178	270	434	445

Average Annual Portfolio Cost Comparisons

Figure 7-29 should be read with the awareness that its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include forecast rate-base costs related to Jackson Prairie storage, the PSE LNG Project and Swarr, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 7-29: Average Portfolio Cost of Gas for Gas Sales Scenarios

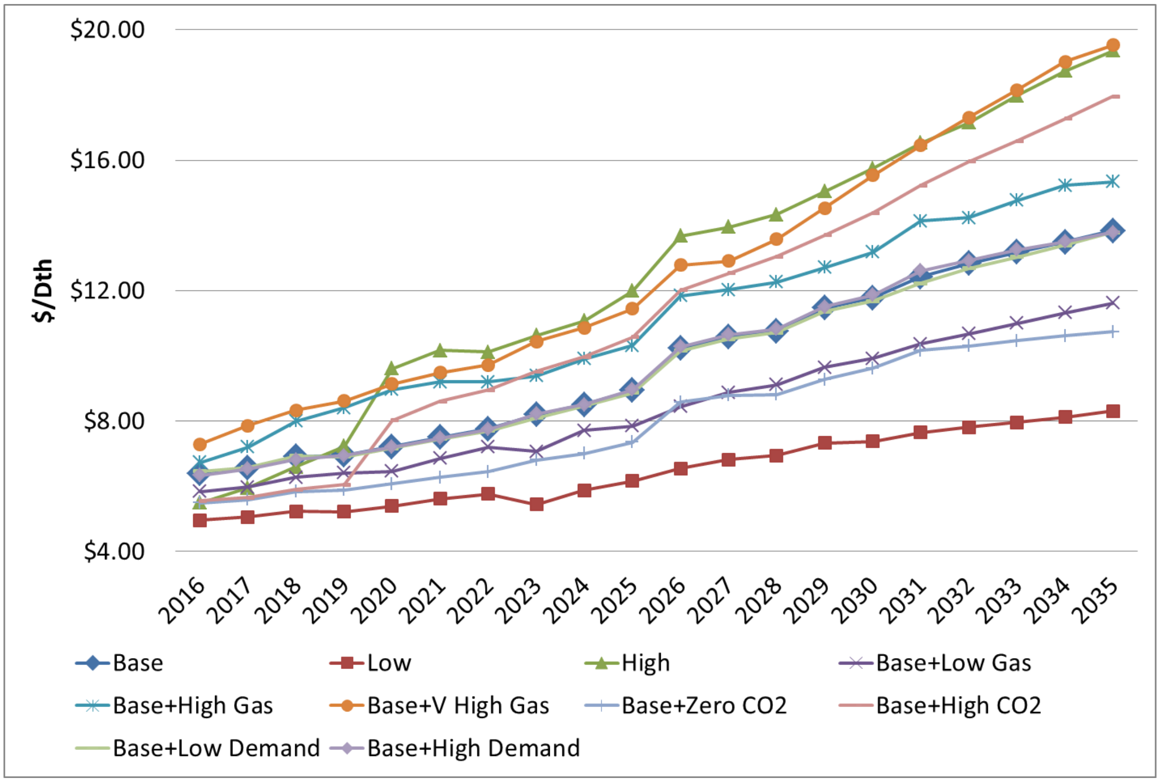


Figure 7-29 shows that average optimized portfolio costs are heavily impacted by the gas prices and CO_2 cost assumptions included in each scenario.

- Changes in customer demand cause only minimal changes in average portfolio costs as shown by the similarity of average portfolio costs in the Base, Base + Low Demand and Base + High Demand Scenarios.
- The Scenarios' costs range from $4.96 to $7.29 per Dth in 2016 to $8.30 to $19.53 per Dth in 2035.
- The Base Scenario portfolio costs are about $6.39 per Dth in 2016, increasing to about $13.83 per Dth by 2035.
- The highest average system cost was in the Base + Very High Gas Price Scenario, which ranged from $7.29 per Dth in 2016 to $19.53 per Dth in 2035. The High Scenario included high CO_2 costs; this helped it track closely to the Base + Very High Gas Price Scenario which included mid CO_2 costs.
- The lowest average portfolio cost was in the Low Scenario which ranged from $4.96 per Dth in 2016 to $8.30 per Dth in 2035. This is because this scenario had the lowest gas price assumptions, no CO_2 costs and low customer demand.

Sensitivity Analyses

Two sensitivities were modeled in the gas sales analysis for this IRP. Sensitivities start with all of the assumptions in the Base Scenario and change one variable. This allows PSE to evaluate the impact of a single resource change on the portfolio. Two sensitivities were tested in the gas analysis for this IRP:

1. ALTERNATE DISCOUNT RATE FOR DSR
Baseline: Demand-side resources are evaluated using the weighted average cost of capital (WACC) assigned to PSE.
Sensitivity: Demand-side resources are evaluated using an alternate discount rate.

2. PIPELINE EXPANSION TIMING
Baseline: Pipeline expansions are built in 2022, 2026 and 2030 because they are allowed only every four years in the model.
Sensitivity: Pipeline expansion is allowed every year starting in 2022.

Alternate Discount Rate Sensitivity. An alternate discount rate was applied 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 first discussed in the April 2014 DSR Technical Advisory Meeting, and later finalized as 1) the weighted 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 weighting was based on the proportionate share of the savings from these customer classes achieved in the most recent program cycle.

Weighted Average Alternate Discount Rate = *Res * LT* CMT_{ave} + *C&I * WACC*
Res_T = *Share of Residential Savings from 2014-15 program cycle (58 percent)*
LT CMT_{ave} = *3 month average of Long Term Constant Maturity Treasury Rate*[9]*(2.87 percent fall 2014)*
$C\&I_T$ = *Share of Commercial & Industrial Savings from 2014-15 program cycle (42 percent)*
WACC = *Weighted Average Cost of Capital for PSE (7.77 percent)*

9 / Source: http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2014

The alternate discount rate used was 4.93 percent (0.58 * 0.0287 + 0.42 * 0.0777). This alternate discount rate was used to estimate the DSR achievable potential for the new DSR bundles (see Figure 7-13). These "alternate discount rate" bundles were then input into the gas portfolio model to obtain the cost-effective level of DSR. It should be noted that this lower discount rate was applied uniformly to both demand and supply-side resources.

The bundles chosen with the alternate discount rate were at the same point on the supply curve for the residential class and one bundle lower for the commercial class of customers. The net effect was that

1. savings from residential customers increased nearly 50 percent,
2. the change in the commercial class was unnoticeable, as the lower bundle had almost the same amount of savings, and
3. the industrial class results were the same in both cases

See Figure 7-30 below for the residential customer DSR savings comparison.

There are slightly more measures – in particular in the residential bundles – since the lower discount rate shifted some of the measures on the margin to the lower cost bundles. Thus the overall cost-effective level of DSR increased on average by about 20 percent by the end of the twentieth year (see Figure 7-31). While the choice of the appropriate discount rate by customer class is still a topic of discussion, a lower discount rate increases the amount of cost-effective DSR, as expected. However, in a real program-level evaluation, such an increase in the level of savings will also impact acquisition costs. Higher administrative costs would need to be reflected in the assumptions, and then the bundles would need to be re-optimized.

Figure 7-30: Compare Cost-effective Level of Gas DSR,
Base vs. Alternate Discount Rate by Customer Class – Residential

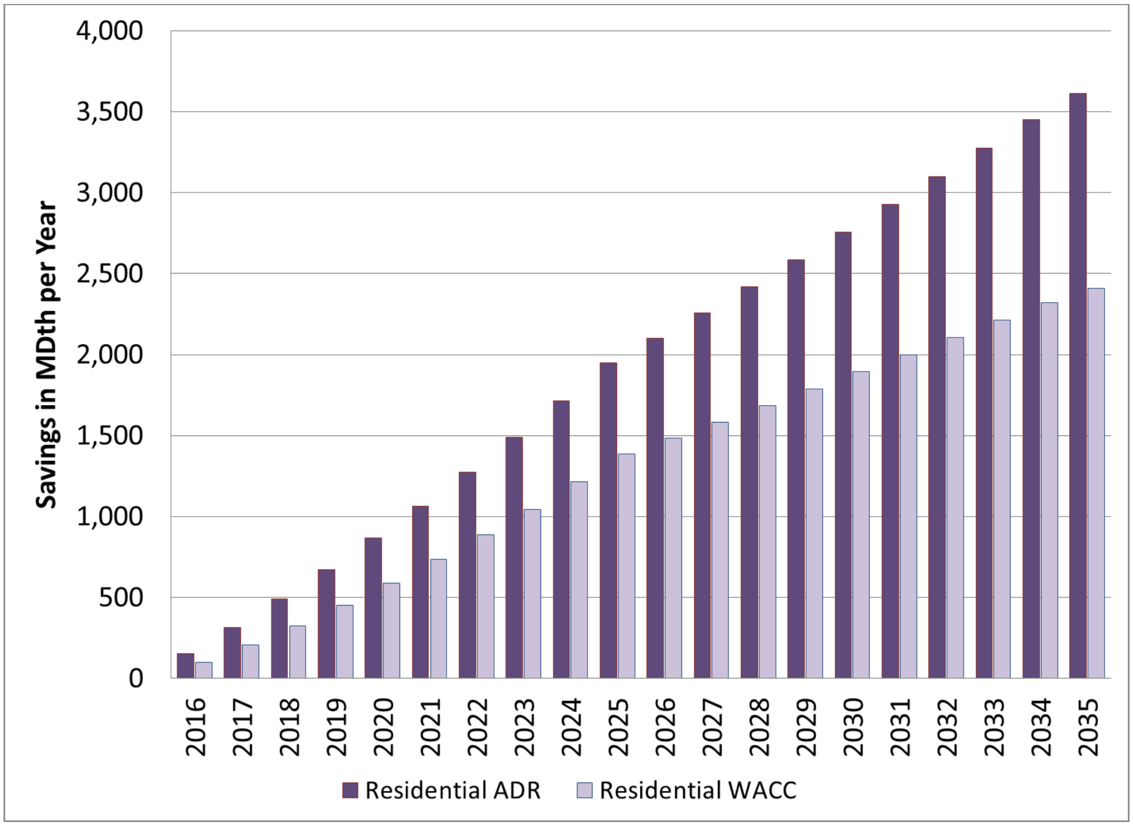
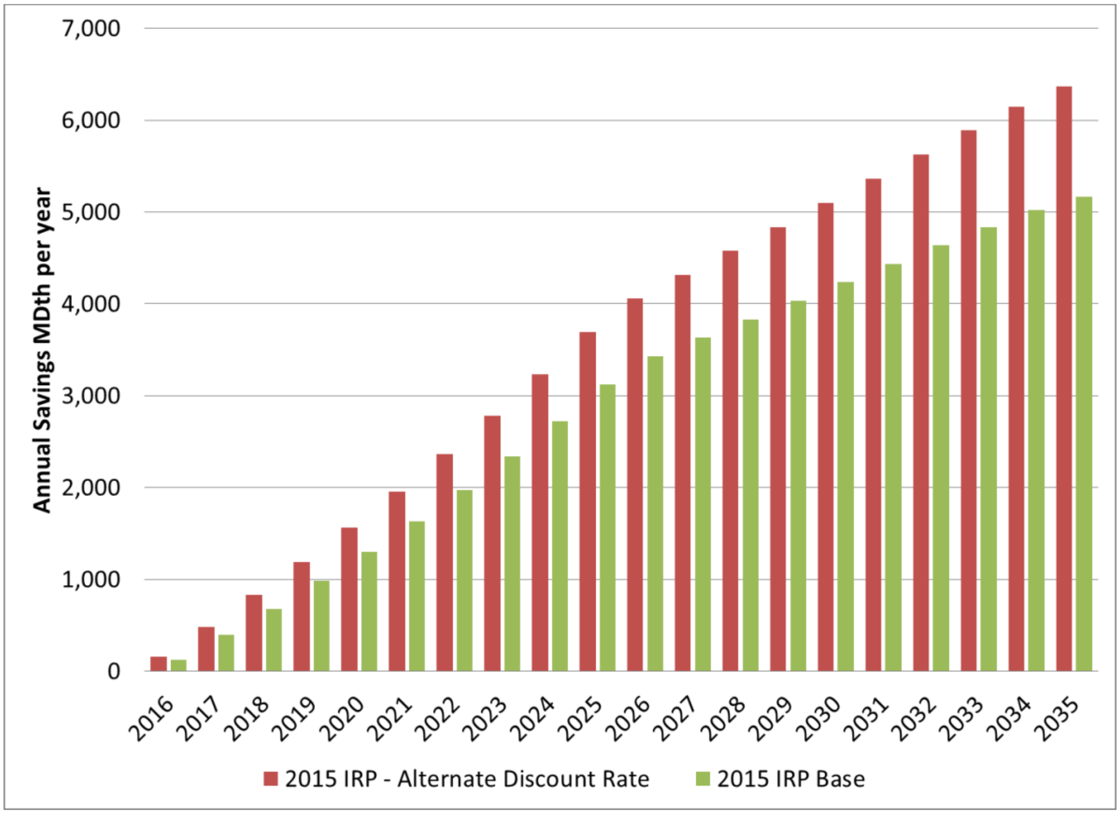


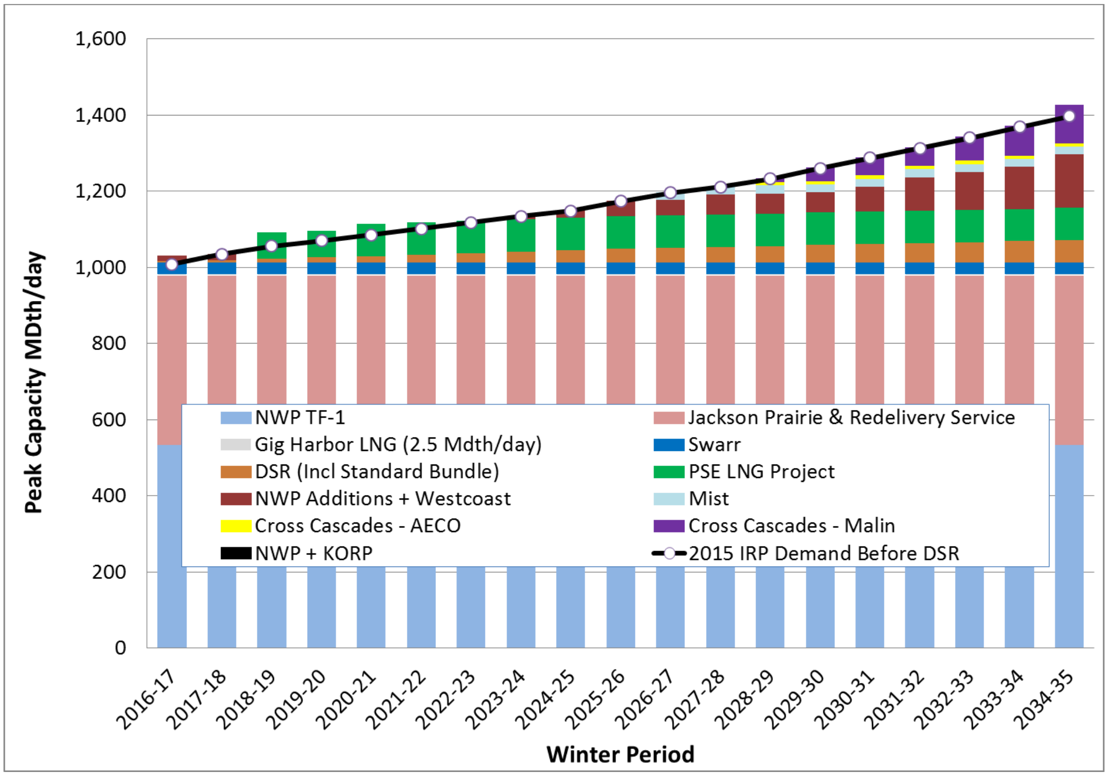
Figure 7-31: Compare Cost-effective Level of Gas DSR, Base vs. Alternate Discount Rate



Pipeline Timing Sensitivity. In response to the WUTC comments in their letter on the 2013 IRP, PSE ran a "Pipeline Timing" sensitivity to find out how allowing the portfolio model to add pipeline expansions more frequently would impact the resource choices made. The 2015 IRP baseline assumption of expansion every four years is a more realistic simulation of the acquisition process, since pipeline expansions must be constructed in larger capacities to make them financially viable, they require longer lead times to build these larger capacity projects.

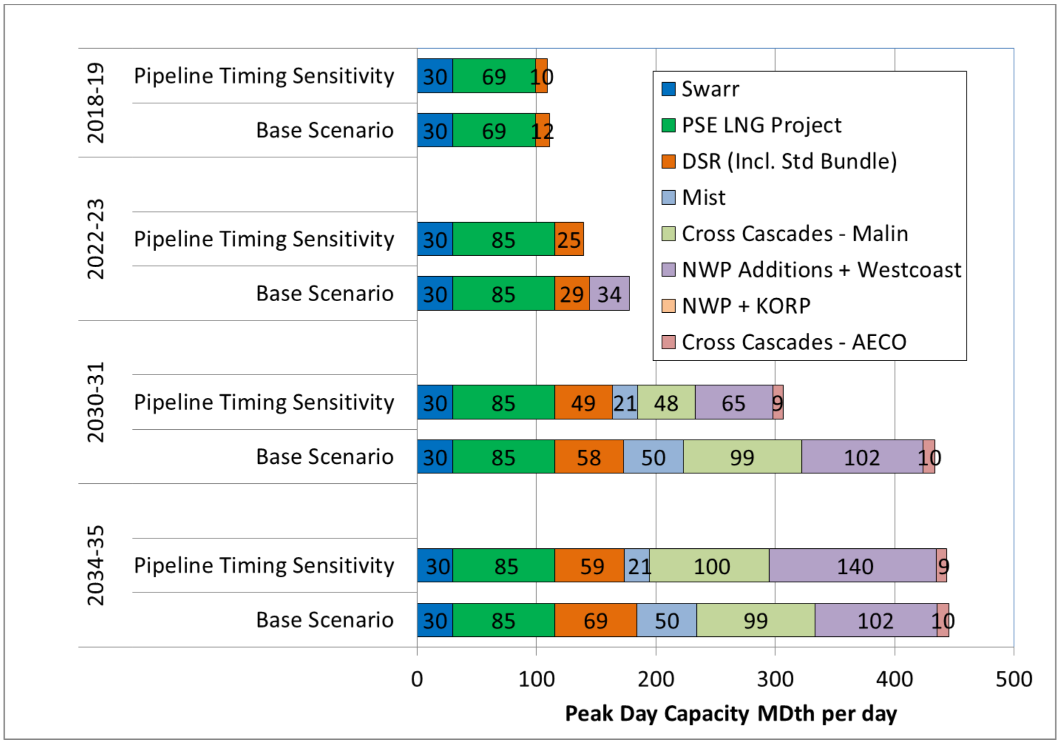
The results of most of the scenarios discussed above show that pipeline expansions were not added till 2022. So, in this sensitivity, the model was modified to allow for pipeline expansion in every year, starting in 2022. As shown in Figure 7-32, the result was a smoother load/resource balance starting in 2022 instead of the step or "lumpy" resource additions that were seen in Figure 7-27 above.

Figure 7-32. Pipeline Timing Sensitivity Gas Resource Portfolio



The portfolio builds for the Pipeline Timing sensitivity are shown in comparison with the Base Scenario portfolio in Figure 7-33 below. The chart below shows that the Swarr and PSE LNG Project non-pipeline resource additions are the same in the Base Scenario as in the Pipeline Timing sensitivity. The GPM indicates that gas pipeline capacity is more cost effective than the Mist storage expansion as it chooses less than half of the Mist storage expansion that was selected in the Base Scenario. DSR for the commercial firm customers is also less in the Pipeline Timing sensitivity. All in all, there is no impact to other resource additions prior to 2030, even when pipeline capacity is added every year versus every four years.

Figure 7-33. Impact on other Resource Builds from Pipeline Timing Sensitivity



KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
ACE	Area Control Error
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada
AFUDC	allowance for funds used during construction
AGC	automatic generation control
AIM	Area Investment Model, used to calculate financial performance indicators for projects.
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours).
AOC	Administrative Order Of Consent
AURORA	One of the models PSE uses for integrated resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions.
BA	Balancing Authority, the area operator that matches generation with load
BACT	Best available control technology, required of new power plants and those with major modifications.
BART	best available retrofit technology, an EPA standard
balancing reserves	Reserves sufficient 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 able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BcF	billion cubic feet
BOP	balance of plant, work inclusive of project substations, turbine foundations, collection system, roads and the operations and main building
BPA	Bonneville Power Administration
BSER	best system of emission reduction, an EPA standard
BTA	Best Technology Available
CAGR	compounded average growth rate

Abbreviation	Meaning
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
capacity factor	The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time.
case	A set of assumptions designed to test the economic viability of an existing resource under a variety of regulatory conditions.
CARB	California Air Resources Board
CCCT	combined cycle combustion turbine
CCR	coal combustion residuals
CCS	carbon capture and sequestration
CEC	California Energy Commission
CFL	compact fluorescent light
CI	confidence interval
CNG	compressed natural gas
CNGC	Cascade Natural Gas Corporation
CO_2	carbon dioxide
COE	U.S. Army Corps of Engineers
COL	construction and operating license
contingency reserves	Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50% of it must be spinning.
Council	Northwest Power and Conservation Council
CPUC	California Public Utility Commission
CRAG	Conservation Resource Advisory Group
CSAPR	Cross State Air Pollution Rule
CT	natural gas-fired combustion turbine
CT peaker	A natural gas-fired, simple-cycle combustion turbine used for meeting peak resource need (also simply referred to as a “peaker”)
CVR	conservation voltage reduction

demand-side resources	resources that originate on the customer or "demand" side of the meter, primarily involving different types of energy efficiency
demand-response	Demand-response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
DOE	Department of Energy
draw	simulation
DSO	dispatch standing order (BPA's protocol to manage a growing amount of wind on its system)
DSR / DSM	demand-side resources, demand-side measures
Dth	dekatherms
EIA	U.S. Energy Information Agency
EIA	RCW 19.285, Washington's state's Energy Independence Act, also commonly known as Initiative 937, sets the state's renewable portfolio standard (RPS).
EIM	Energy Imbalance Market. A voluntary, within-hour energy market operated by the California Independent System Operator (CAISO) that trades in very small increments such as 5 and 15 minutes.
EISA	Energy Independence and Security Act
ELCC	equivalent load carrying capability
EPA	Energy Policy Act (2005)
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Washington state's Emissions Performance Standard
ESP	electric service provider
ESP	electro-static precipitator
EUE	Expected unserved energy, a reliability metric measured in MWhs focused on magnitude of electric service curtailment events (how widespread outages may be).
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
firm capacity	Firm pipeline transportation capacity carries the right, but generally not the obligation, to transport up to a maximum daily quantity of gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported.

GDP	gross domestic product
GHG	greenhouse gas
GPM	Gas portfolio model. PSE currently uses the SENDOUT model from ABB Ventyx as its GPM.
GRC	General Rate Case
GTN	Gas Transmission Northwest
HDD	heating degree days
Heat rate	a measure of the thermal efficiency of a power plant or generator
HHV	high heating value
HVAC	heating, ventilation and air conditioning
I-937	Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, Energy Independence Act.
ICE	Incremental capacity equivalent, the peak capacity contribution of a resource relative to that of a gas peaker. 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.
iDOT	Investment Optimization Tool, to identify a set of projects that will create maximum value.
IGCC	Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier.
IOU	investor owned utility
Interruptible capacity	See non-firm capacity.
IPP	Independent power producers
IRP	Integrated Resource Plan
IRPAG	Integrated Resource Plan Advisory Group
ISO	independent system operator
KORP	the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal sponsored by Fortis BC and Spectra
kV	kilovolt
kW	kilowatt
kWh	kilowatt hours
LADWP	Los Angeles Department of Water and Power

LBNL	Lawrence Berkeley National Laboratory
LNG	liquefied natural gas
load	the total generated demand plus planning margins and operating reserve obligations
LOLH	Loss of load hours, a reliability metric focused on the duration of electric service curtailment events (how long outages may last).
LOLP	Loss of load probability, a reliability metric focused on the likelihood of an electric service curtailment event happening.
LP	linear program
LP-Air	vaporized propane air
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	maximum daily quantity
MDth	thousand dekatherms
Mid-Columbia (Mid-C) market hub	The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC, located on the Mid-Columbia River.
MMBtu	million British thermal units
MSTI	Northwestern Energy's Mountain States Transmission Intertie
MW	megawatt
MWe	megawatts electric
MWh	megawatt hours
NAAQS	National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead.
NARUC	National Association of Regulatory Utility Commissions
NEEA	Northwest Energy Efficiency Alliance
NEEDS	National Electric Energy Data System
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
net maximum capacity	The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.
NGV	natural gas vehicles

Non-firm capacity	Non-firm service is subordinate to the rights of shippers who hold and use firm transportation capacity, hence it is “interruptible.” The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.
NOS	Network Open Season, a BPA transmission planning process
NO_x	nitrogen oxides
NPV	net present value
NRC	Nuclear Regulatory Commission
NREL	National Renewables Energy Laboratories
NSPS	New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction.
NUG	nonutility generator
NWGA	Northwest Gas Association
NWP	Northwest Pipeline (only pipeline directly to west WA)
NPCC	Northwest Power & Conservation Council
NWPP	Northwest Power Pool
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OFM	Washington state Office of Financial Management
OTC	once-through cooling
PCA	power cost adjustment (electric)
PCORC	power cost only rate case
peak capacity value	A measure of a resource’s ability to contribute to meeting peak need.
peaker	Natural gas-fired combustion turbine used for meeting peak resource need (also sometimes referred to as a simple-cycle combustion turbine, SCCT or CT peaker, or reciprocating engine).
PEFA	ColumbiaGrid’s planning and expansion functional agreement, which defines obligations under its planning and expansion program
PGA	purchased gas adjustment
PG&E	Pacific Gas & Electric
PGE	Portland Gas Electric
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
planning margin or PM	These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events.

planning standards	The performance targets for a system's operation.
PM	particulate matter
PNUCC	Pacific Northwest Utilities Coordinating Committee
portfolio	A specific mix of resources to meet gas sales or electric load.
PPA	Purchased power agreement, a bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point.
PTP	Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD).
PTSA	Precedent Transmission Service Agreement
PSE	Puget Sound Energy
PSIA	Pipeline Safety Improvement Act (2002)
PSM	Portfolio screening model, a model PSE uses for integrated resource planning, which tests electric portfolios to evaluate PSE's long-term revenue requirements for those portfolios.
PSO	power supply operations
PTC	Production Tax Credit, a federal subsidy for production of renewable energy that applied to projects that began construction in 2013 or earlier. When it expired at the end of 2014, it amounted to $23 per MWh for a wind project's first 10 years of production.
PUD	public utility district
PV	photovoltaic
R&D	research and development
RAM	Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to asses physical resource adequacy.
RAS	remedial action scheme
rate base	The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes.
RCRA	Resource Conservation Recovery Act
RCW	Revised Code of Washington
RCW 19.285	Washington's state's Energy Independence Act, commonly referred to as the state's renewable portfolio standard ("RPS")

REC	Renewable energy credit, RECs are intangible assets that represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources.
REC banking	Washington's renewable portfolio standard allows for RECs unused in the current year to be "banked" and used in the following year.
recip	Short for reciprocating engine, a small four-stroke gas engine that uses a lean burn method to generate power. Used as a peaker.
regulatory lag	The time that elapses between establishment of the need for funds and the actual collection of those funds in rates.
revenue requirement	Rate Base * Rate of Return + Operating Expenses
RFP	request for proposal
RPG	Renewable Portfolio Goal
RPS	Renewable portfolio standard. It requires electricity retailers to acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3% by 2012, 9% by 2016 and 15% by 2020.
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SCCT	Simple-cycle combustion turbine, natural gas-fired unit used for meeting peak resource need (also sometimes referred to as a "peaker")
SCR	selective catalytic reduction
scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SENDOUT	PSE's model used to help identify the long-term least cost combination of gas resources to meet stated loads.
sensitivity	A set of data assumptions based on the Base Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SNL	A company that collects and disseminates corporate, financial and market data on several industries including the energy sector (www.snl.com). The letters SNL stand for savings and loan.
SO_2	sulfur dioxide
SOFA system	separated over-fire air system

supply-side resources	Resources that originate on the utility side of the meter. Electric supply-side resources include primarily coal and gas-fired generation, hyro power and transmission. Gas supply-side resources include pipeline capacity and gas supplies.
TAG	Technical Advisory Group
TailVar90	A metric for measuring risk defined as the average value of the worst 10 percent of outcomes.
TEPPC	WECC Transmission Expansion Planning Policy Committee
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TF-1	Firm gas transportation contracts, available 365 days each year.
TF-2	Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only.
T&D	transmission and distribution
TOP	transmission operator
transport loads	In the gas utility, this refers to customers who buy gas supplies from PSE but transport those supplies using their own resources
transportation loads	The natural gas or electricity that is used to fuel vehicles like cars, trucks, boats and ships.
Treasury Grant	The Treasury Grant ("Grant) is a federal subsidy in the form of a cash payment that amounts to 30% of the eligible capital cost for renewable resources; it expires at the end of 2013. For projects placed in service in 2013, construction must have started in 2009, 2010 or 2011 and the project must meet eligibility criteria.
UPC	use per customer
VERs	Variable energy resources
VectorGas	facilitates the ability to model price and load uncertainty
WAC	Washington Administrative Code
WACC	weighted average cost of capital
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WECo	Western Energy Company
WEI	Westcoast Energy, Inc.
WIEB	Western Interstate Energy Board
WUTC	Washington Utilities and Transportation Commission