2017 PSE Integrated Resource Plan

Chapters 1-8

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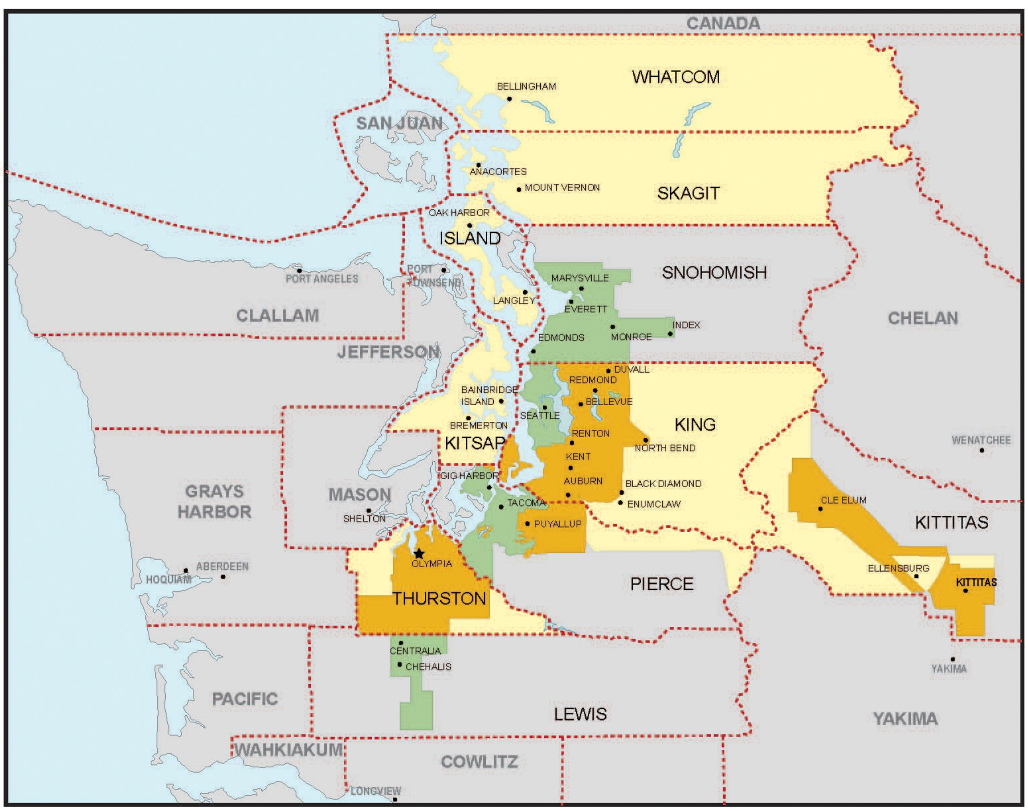
PUGET SOUND ENERGY

2017 PSE Integrated Resource Plan

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. Our service area covers more than 6,000 square miles, stretching 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 800,000 natural gas customers in 10 counties.



Combined electric and natural gas service
Electric service
Natural gas service

2017 PSE Integrated Resource Plan

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Key Definitions and Acronyms

Term/Acronym	Definition
AARG	average annual rate of growth
AB32	The California Global Warming Solutions Act of 2006, which mandates a carbon price be appied to all power generated in or sold into that state.
ACE	Area Control Error
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada.
AMI	advanced metering infrastructure
AMR	automated meter reading
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
ARMA	autoregressive moving average
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.
BAA	Balancing Authority area
BACT	Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations.
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 must be able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BART	Best available retrofit technology, an EPA requirement for certain power plant modifications.
Base Scenario	In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making.

Term/Acronym	Definition
Baseload gas plants	Baseload generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year. Generally combined-cycle combustion turbines (CCCTs).
baseload resources	Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need.
Bcf	billion cubic feet
BEM	Business Energy Management sector, for electric energy efficiency programs.
BES	Bulk Electric System
BPA	Bonneville Power Administration
BSER	Best system of emissions reduction, an EPA requirement for certain power plant construction or modification.
BTU	British thermal units
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.
CAP	Corrective action plans. A series of operational steps used to prevent system overloads or loss of customers' power.
CAR	the Washington state Clean Air Rule
CARB	California Air Resources Board
CCCT	Combined-cycle combustion turbine. These are baseload gas plants that consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator.
CCR	coal combustion residuals
CCS	carbon capture and sequestration
CDD	cooling degree day
CEC	California Energy Commission
CI	confidence interval
CNG	compressed natural gas
CO2	carbon dioxide
CO2e	carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
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 percent of it must be spinning.

Term/Acronym	Definition
CPI	consumer price index
CPP	federal Clean Power Plan
CPUC	California Public Utilities Commission
CRAG	PSE's Conservation Resource Advisory Group
CT	Natural gas-fired combustion turbine, also referred to as a "peaker."
CVR	conservation voltage reduction
Demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
demand-side resources	These resources reduce load and originate on the customer side of the meter. PSE's primary demand-side resources are energy efficiency and customer programs.
Deterministic analysis	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.
distributed generation	Small-scale electricity generators like rooftop solar panels, located close to the source of the customer's load.
DOE	U.S. Department of Energy
DSM	demand-side measure
DSO	Dispatcher Standing Order
DSR	demand-side resources
Dth	dekatherms
dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EIA	U.S. Energy Information Agency
EIM	The Energy Imbalance Market operated by CAISO.
EIS	environmental impact statement
EITEs	energy-intensive, trade-exposed industies
ELCC	Expected load carrying capacity. The peak capacity contribution of a resource relative to that of a gas-fired peaking plant.
ELCC	expected load carrying capacity
EMC	Energy Management Committee
energy need	The difference between forecasted load and existing resources.
energy storage	A variety of technologies that allow energy to be stored for future use.
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard
ERU	Emission reduction units. An ERU represents one MtCO2 per year.

Term/Acronym	Definition
ESS	energy storage systems
EUE	Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be).
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	final implementation plan
GDP	gross domestic product
GENESYS	The resource adequacy model used by the Northwest Power and Conservation Council (NPCC).
GHG	greenhouse gas
GPM	gas portfolio model
GRC	General Rate Case
GTN	Gas Transmission Northwest
GW	gigawatt
HDD	heating degree day
HVAC	heating, ventilating and air conditioning
I-937	Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act.
iDOT	Investment Optimization Tool. An analysis tool that helps 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.
intermittent resources	Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power.
IOU	investor-owned utility
IPP	independent power producer
IRP	integrated resource plan
IRPAG	PSE's Integrated Resource Plan Advisory Group
ISO	independent system operator
ITA	independent technical analysis
ITC	investment tax credit
KORP	Kingsvale-Oliver Reinforcement Project pipeline proposal
kV	kilovolt
kW	kilowatt
kWh	kilowatt hours

Term/Acronym	Definition
LAES	liquid air energy storage
LNG	liquified natural gas
load	The total of customer demand plus planning margins and operating reserve obligations.
LOLH (or LOLE)	Loss of load hours (or loss of load energy), 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-Air	vaporized propane air
LSR	Lower Snake River Wind Facility
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	maximum daily quantity
MDth	thousand dekatherms
MEIC	Montana Environmental Information Center
MESA	Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems.
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
MMtCO2e	million metric tons of CO2 equivalent
MSA	metropolitan statistical area
MW	megawatt
MWh	megawatt hour
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.
nameplate capacity	The maximum capacity that a natural gas fired unit can sustain over 60 minutes when not restricted to ambient conditions.
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.
net metering	A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE.
NGV	natural gas vehicles
NO2	nitrogen dioxide
NOS	Network Open Season, a BPA transmission planning process

Term/Acronym	Definition
NO_x	nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	net present value
NRC	Nuclear Regulatory Commission
NREL	National Renewables Energy Laboratories
NRF	Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC.
NSPS	New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction.
NUG	non-utility generator
NWE	NorthWestern Energy
NWGA	Northwest Gas Association
NWP	Northwest Pipeline
NWPP	Northwest Power Pool
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OTC	once-through cooling
PACE	PacifiCorp East
PACW	Pacificorp West
PCA	power cost adjustment (electric)
PCORC	power cost only rate case
peak need	Electric or gas sales load at peak energy use times.
peaker (or peaking plants)	Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spies in need. They are not intended to operate economically for long periods of time like baseload generators.
peaking resources	Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest.
PEFA	ColumbiaGrid’s planning and expansion functional agreement, which defines obligations under its planning and expansion program.
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
PGA	purchased gas adjustment
PGE	Portland General Electric
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)

Term/Acronym	Definition
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 metrics selected as performance targets for a system's operation.
PLEXOS	An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real-time to match changes in supply and demand on a 5-minute basis.
PM	particulate matter
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
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.
PRP	Pipeline Replacement Program
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.
PSRC	Puget Sound Regional Council
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.
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
PUD	public utility district
pumped hydro	Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station.
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.

Term/Acronym	Definition
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)
RCW 80.80	Washington state law that sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or enteringinto long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.
REC	Renewable energy credit. RECs are intangible assets which 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.
redirected transmission	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
regulatory lag	The time that elapses between establishment of the need for funds and the actual collection of those funds in rates.
REM	Residential Energy Management sector, in energy efficiency programs.
repowering	Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015.
revenue requirement	Rate Base x Rate of Return + Operating Expenses
RFP	request for proposal
RPS	Renewable portfolio standard. It requires electricity retailers to acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent 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 called a "peaker")
scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SCR	selective catalytic reduction

Term/Acronym	Definition
SENDOUT	The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will 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.
SEPA	Washington State Environmental Policy Act
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO2	sulfur dioxide
SOFA system	separated over-fire air system
Solar PV	solar photovoltaic technology
Stochastic analysis	Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios 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 CO2 prices.
supply-side resources	Resources that generate or supply electric power, or supply natural gas to gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
T&D	transmission and distribution
TAG	Technical Advisory Group
TailVar90	A metric for measuring risk defined as the average value of the worst 10 percent of outcomes.
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)
TC-Foothills	TransCanada-Foothills Pipeline
TC-GTN	TransCanada-Gas Transmission Northwest Pipeline
TC-NGTL	TransCanada-Nova Gas Transmission Pipeline
TEPPC	WECC Transmission Expansion Planning Policy Committee
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.
thermal resources	Electric resources that use carbon-based fuels to generate power.
TOP	transmission operator
transmission redirect	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.

Term/Acronym	Definition
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the gas utility for distribution service.
UPC	use per customer
VectorGas	An analysis tool that facilitates the ability to model price and load uncertainty.
VERs	Variable energy resources
WAC	Washington Administrative Code
WACC	weighted average cost of capital
WCI	Western Climate Initiative
WCPM	Wholesale Market Curtailment Model
WECC	Western Electricity Coordinating Council
WECo	Western Energy Company
WEI	Westcoast Energy, Inc.
Westcoast	Westcoast Energy, Inc
Wholesale market purchases	Generally short-term purchases of electric power made on the wholesale market.
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
ZLD	zero liquid discharge

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2017 PSE Integrated Resource Plan

Executive Summary

The IRP is 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.

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1. OVERVIEW

The resource plan forecast presented in the 2017 IRP presents exciting changes in resource outlook and preserves a strategic agility that will allow PSE to respond to rapidly changing conditions as renewable and storage technologies mature, as the impacts of carbon regulation and climate change become clearer, and as customer behavior changes. The forecast relies on additional transmission to market to meet peak capacity need, continued strong investment in conservation, utility-scale solar to meet renewable resource need, and energy storage. While many of these changes have been on the horizon for some time and discussed extensively in the media and by advocacy groups, this is the first time that some appear to truly be part of a low-cost, low-risk resource plan for PSE's customers.

Exciting Changes in Resource Outlook

- **EMERGENCE OF SOLAR POWER**. Wind has dominated new renewable resource additions in the Pacific Northwest. This IRP finds solar power in eastern Washington appears to be a cost-effective renewable resource for the first time.
- **ENERGY STORAGE AND DEMAND RESPONSE INSTEAD OF FOSSIL FUEL GENERATION**. Energy storage and demand response resources can help push PSE's need for capacity resources out eight years, to 2025. This is a low-cost and low-risk strategy that helps avoid locking PSE's customers into a long-lived fossil fuel plant while alternative technology is evolving rapidly and greenhouse gas policies are being developed.
- **REDIRECTING TRANSMISSION TO INCREASE MARKET ACCESS**. PSE can reassign some transmission from intermittent wind resources to the Mid-C market in a way that will allow PSE to expand its access to short-term bilateral markets on a firm basis, while still allowing us to deliver that wind energy to our customers. Increasing market reliance is low cost alternative for our customers. This IRP includes a comprehensive analysis of market risk in relation to Pacific Northwest's resource adequacy outlook, built on Northwest Power and Conservation Council (NPCC), Bonneville Power Administration (BPA) and Pacific Northwest Utilities Conference Committee (PNUCC) analyses. It finds the region is nearly meeting its resource adequacy target, and with continued strong conservation programs, it may become even more reliable in the future. This is not without risk, but PSE has analyzed these risks extensively and concluded the risks are reasonable. Redirecting transmission supports the strategy to push out the need for additional fossil fuel plants to 2025, while rapidly evolving technology drives down the

costs of resource alternatives and uncertainty in greenhouse gas regulation can be resolved.

- **ENERGY EFFICIENCY.** One thing remains the same in this IRP – PSE's commitment to strong investment in encouraging customers to use energy more efficiently. Devoting significant resources to help our customers use energy more wisely is a tried and true way of reducing costs, cost risks and the environmental footprint of PSE's operations as well as our customers'.
- **NATURAL GAS UTILITY RESOURCE PLAN.** Strategic agility is also the hallmark of the natural gas utility resource plan. Continued conservation investment, completion of the Tacoma LNG peaking facility and the option to upgrade PSE's propane peaking facility (Swarr) push out the need to lock our natural gas customers into lengthy contracts to expand regional pipeline infrastructure. Again, this is a low-cost and low-risk resource strategy for our gas customers.

Impact of Uncertainty in Carbon Regulation

PSE recognizes the importance of mitigating climate change. The Base Scenario in this IRP models the impacts of Washington state's Clean Air Rule (CAR) and the federal Clean Power Plan (CPP). Even though the fate of both regulatory programs is uncertain at this time, some form of carbon regulation is likely to be enacted during the next 20 years, so it is important to reflect this possibility in the analysis. We expect these rules to evolve and for new ones to be developed. The resource plan presented here gives us the flexibility and agility to adapt to changes without having to commit our customers to long-lived fossil fuel resources at this time.

The design of carbon regulation is critically important to achieving meaningful carbon reductions and avoiding unintended consequences. For instance, the IRP analysis indicates that CPP rules may distort the value of peaking plants, making them appear more economic than energy storage. And, it is likely that the CAR will shift dispatch to less carbon-efficient plants by focusing only on Washington gas-fired plants, which are some of the most carbon-efficient in the Western Energy Coordinating Council (WECC), increasing carbon emissions in the region even though emissions in Washington state decline.

PSE is committed to working with policy makers and others to help modify and create approaches to greenhouse gas regulation that are effective at reducing carbon emissions in a way that minimizes the impact of costs on our customers. See Chapter 3, Planning Environment, for further discussion of this issue.

The Future of Colstrip

The coal-fired Colstrip plant emits a significant amount of greenhouse gasses, but it has historically been a very low cost resource, and PSE is obligated to minimize costs to customers within existing legal frameworks. The multiple ownership structure of Colstrip includes an independent power producer and utilities that serve load in six states, which creates a very complex decision-making process.

Units 1 & 2 are scheduled to retire no later than July, 2022, and the analysis indicates that retiring those plants earlier would be uneconomic. After Units 1 & 2 retire, additional conservation, demand response, energy storage batteries and firm transmission to market are expected to meet resource needs until 2025.

The continued operation of Units 3 & 4 is highly dependent on future environmental regulation. Analysis in this IRP demonstrates that a carbon regulation policy that adds to the dispatch cost of Colstrip would challenge its continued economic operation. Absent such a policy, Colstrip 3 & 4 appear to be economic to operate for the foreseeable future.

In the absence of Colstrip Units 3 & 4, the analysis currently indicates that peaking plants are the most cost-effective alternative to meeting need, but this conclusion will be revisited as the entire region continues to invest heavily in energy efficiency, emerging technologies continue to evolve, and the impacts of carbon regulation become clearer.

A Forecast, Not a Prescription

The IRP process is a legal mandate that requires PSE to identify the least cost combination of energy conservation and energy supply resources to meet the needs of our customers. Specific energy efficiency and supply-side resource decisions are not made in the context of the IRP. The primary value of the IRP is what we learn from the opportunity to do three things: develop key analytical tools to aid in making prudent decision making for long-term energy efficiency and energy supply, create and manage expectations about the near future, and think broadly about the next two decades.

The portfolio analysis presented in the IRP is 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 next.

2. 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 interpret the resource plans produced in the IRP analysis as 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. The Action Plans describe the activities PSE will execute resulting from the forecasting exercise.

Electric Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs that will put us on a path to achieve an additional 374 MW of energy efficiency by 2023 through program savings combined with savings from codes and standards.

2. Demand Response

Clarify the acquisition, prudence criteria and cost recovery process for demand response programs. Issue a demand response RFP based on those findings. Re-examine the peak capacity value of demand response programs in the 2019 IRP to include day-ahead demand response programs, and use the sub-hourly flexibility modeling capability developed in this IRP to value sub-hourly demand response programs.

Pursuant to the 2015 IRP action plan, PSE issued an RFP for demand response programs in 2016. That led PSE to identify policy issues that need to be resolved with regard to demand response programs.

POLICY ISSUES. Demand response is a portfolio of programs that involves relationships with customers. Some programs are pricing structures that require revised tariffs and updates to metering and billing systems. Thus, in terms of program planning, demand response is more like conservation programs than power plants. However, demand response has been excluded from the program planning design and cost recovery process used for conservation. The current processes for establishing prudence related to acquiring power plants or contracts and recovering costs through a Power Cost Only Rate Case (PCORC) do not fit for a portfolio of demand response programs that build over time. The WUTC has begun exploring these issues. PSE will be fully engaged, as this is a critical path item for being able to execute demand response to meet resource need and an essential component for postponing the need to build fossil fuel generation.

DEMAND RESPONSE RFP. Once there is line of sight on resolving policy barriers, PSE will issue a demand response RFP. This IRP applied the PSE resource adequacy modeling framework used for other kinds of resources to demand response. These findings will be included in the demand response RFP to provide better guidance to bidders on the value of duration, frequency, and the interval between demand response events.

VALUING ADDITIONAL TYPES OF DEMAND RESPONSE PROGRAMS. Fast-acting demand response is able to respond quickly, creating additional sub-hourly flexibility value in addition to potentially offsetting or delaying the need for a peaking generator. PSE will use its sub-hourly flexibility modeling capability to value sub-hourly demand response programs in the 2019 IRP. Another category of demand-response to examine in more detail is day-ahead programs. Although day-ahead demand response programs will not deliver the same benefit, they may still be a valuable resource, so PSE will also examine the peak capacity value of day-ahead demand response programs in its 2019 IRP.

3. Energy Storage

Install a small-scale flow battery to gain experience with the operation of this energy storage system in anticipation of greater reliance on flow batteries in the future.

4. Supply-side Resources: Issue an All-source RFP

Issue an all-source RFP in the first quarter of 2018 that includes updated resource needs and avoided cost information.

PSE has a need for renewable and capacity resources as early as 2022, after cost-effective conservation and demand response are accounted for.

RENEWABLE RESOURCES. Bringing on future additional renewable resources, whether in PSE's balancing authority or in BPA's, may require transmission system upgrades that will require long lead times to study, design, permit and construct. While this IRP finds eastern Washington solar power is more cost effective than wind, the results are close. Montana wind would be a "qualifying renewable resource" if it were delivered to Washington state on a real-time basis without shaping or storage. Addressing this qualification constraint will likely require a complex set of transmission studies, coordinated with Northwestern in Montana, BPA and possibly the WECC. Issuing an RFP in 2018 for delivery beginning in 2022 will provide potential respondents time to address such transmission issues.

SUPPLY-SIDE RESOURCES FOR CAPACITY. While we believe that demand response and energy storage will be a reasonable, cost-effective resource that is sufficient to meet the capacity need that appears in 2022, this assumption will be investigated further in an RFP. Issuing an RFP in 2018 for delivery in 2022 is reasonable because the regional transmission system is becoming constrained, and potential respondents may need time to address these constraints, depending on the location of the proposed resources. Furthermore, some resources, like pumped hydro storage, may have long lead times. Finally, some kinds of renewable resources can contribute to meeting peak capacity, so considering capacity resources in this RFP will help align valuation processes.

5. Develop Options to Mitigate Risk of Market Reliance

Develop strategies to mitigate the risk of redirecting transmission and increasing market reliance.

PSE relies heavily on the short-term market to meet the energy and peak capacity needs of our customers. Risk associated with this exposure to market is managed in the short term; long term, however, regional resource adequacy cannot be addressed without adding new resources. If regional resource adequacy assessments are off or unexpected demand-side or supply-side shocks happen that render the region short of resources, the burden of the resulting deficits would fall on PSE's customers. Therefore, PSE will develop strategies mitigate this risk. These strategies may include:

- maintaining options to build capacity resources quickly;
- re-examining PSE policies with regard to how much of its market reliance should be managed via short-term purchases versus long-term contracts; and
- working with others in the region on options for PSE to join or to help develop functioning wholesale markets that incorporate, energy, capacity and flexibility services.

6. Energy Imbalance Market (EIM)

Continue to participate in the California Energy Imbalance Market for the benefit of our customers.

PSE's participation in the EIM allows 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. Participation also gives 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 reduces power costs to our customers.

7. Regional Transmission

Examine regional transmission needs in the 2019 IRP in light of efforts to reduce the region's carbon footprint.

Future progress on reducing the region's carbon footprint will necessarily involve both retirement of less carbon-efficient thermal resources and the addition of renewable resources. This will make the ability of the region's transmission resources to move power to where it is needed an increasingly important issue. This examination will include the following.

- Assess the operational risk associated with redirecting transmission from PSE's existing wind resources and address those risks if necessary.
- Coordinate with the WUTC, other utilities and stakeholders to study the alternatives for re-purposing transmission used for Colstrip 1 & 2 as these units are retired.
- Begin to coordinate with other utilities and transmission providers to understand alternatives for re-purposing transmission from Colstrip 3 & 4, so that PSE will be prepared should the plant be retired earlier than anticipated.

Natural Gas Sales Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 14 MDth per day of capacity by 2022 through program savings and savings from codes and standards.

2. LNG Peaking Plant

Complete the PSE LNG peaking project located near Tacoma.

Construction of the facility is under way and should be completed in time for the storage project to be filled for the 2019/20 heating season. This resource is essential to delaying investment in additional interstate and international year-round pipeline capacity.

3. Option to Upgrade Swarr

Maintain the ability upgrade the Swarr propane-air injection system in Renton, which the plan forecasts will be needed by the 2024/25 heating season.

Upgrading the Swarr LP-Air facility's environmental safety and reliability systems to return the facility to its maximum output of 30 MDth per year was selected as least cost in all but the low demand scenarios in the IRP analysis. This short lead time project is also within PSE's control, and the timing of the upgrade can be fine-tuned by PSE in response to load growth.

3. 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 for resource adequacy, hourly energy and sub-hourly flexibility. 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. Beyond operating reserves, sub-hourly flexibility is also required. The robust sub-hourly analytical framework implemented in this IRP determined that PSE has sufficient sub-hourly flexibility at this time, although we will continue to refine this analysis. In addition to meeting customers' physical and sub-hourly flexibility 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 1-1 presents electric peak hour capacity need.
- Figure 1-2 presents the electric energy need (the annual energy position for the 2017 Base Scenario).
- Figure 1-3 presents PSE's renewable energy credit need.

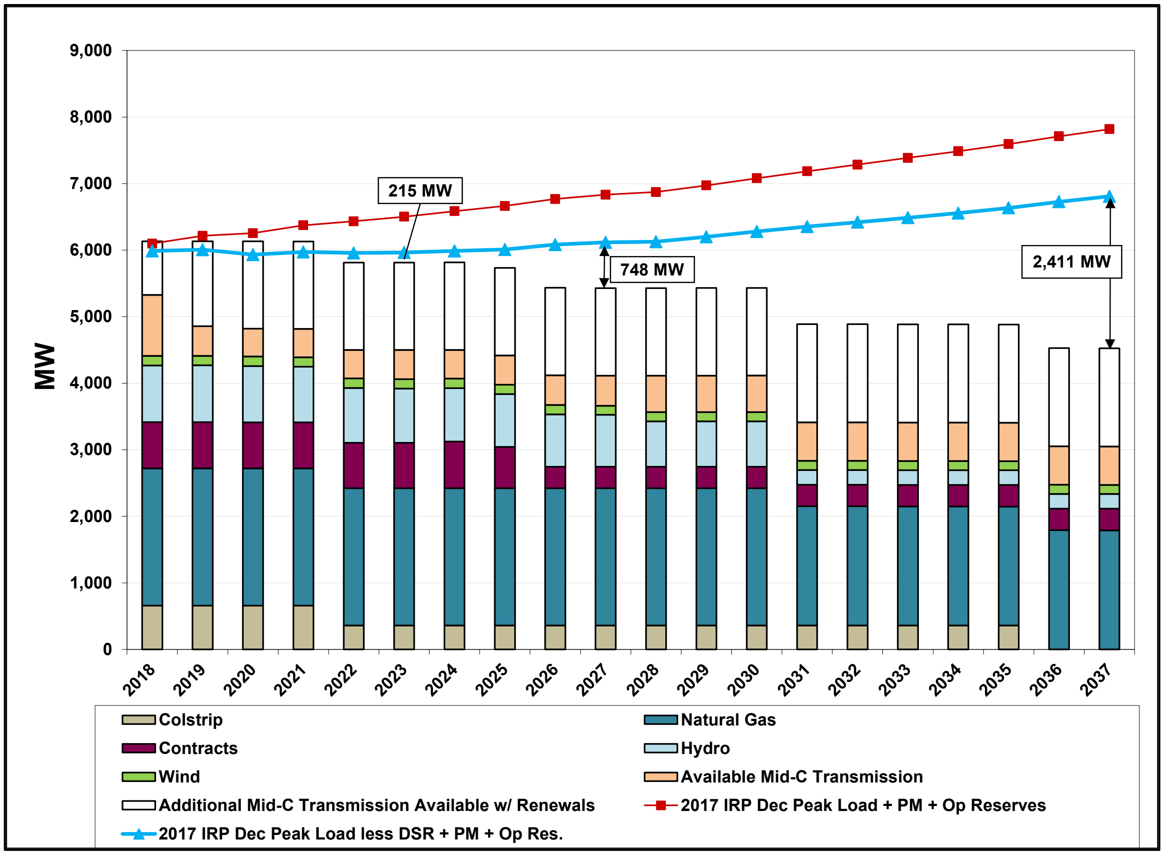
Electric Peak Hour Capacity Need

Figure 1-1 compares the existing resources available to meet peak hour capacity[1] with the projected need over the planning horizon. The electric resource outlook in the Base Scenario indicates the initial need for an additional 215 MW of peak hour capacity by 2023. This includes a 13.5 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE's 5 percent loss of load probability (LOLP) planning standard. Figure 1-1 shows four noticeable drops in PSE's resource stack. The first, in 2022, is caused by retirement of Colstrip 1 & 2, approximately 300 MW of capacity. The second is at the end of 2025, when PSE's 380 MW coal-transition contract with Transalta expires upon retirement of the Centralia coal plant.[2] The third occurs in 2031, when PSE contracts with Chelan PUD for 481 MW of hydro output expire. The final significant drop is in 2035, the year that the Base Scenario assumes retirement of Colstrip Units 3 & 4, of which PSE owns 370 MW. This could occur sooner, depending on how future

1 / Resource capacities illustrated here reflect the contribution to peak, not nameplate capacity, so PSE's approximate 130 MW update with Skookumchuck of owned and contracted wind appear very small on this chart. Refer to Chapter 6, Electric Analysis, for how peak capacity contributions were assessed.
2 /PSE entered the coal transition contract with Transalta under RCW 80.80 to facilitate the retirement of the only major coal-burning power plant in Washington state.

environmental regulations affect the economics of running the plant. 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 1-1; the lower line includes the benefit of DSR while the upper line does not.

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



Electric Energy Need

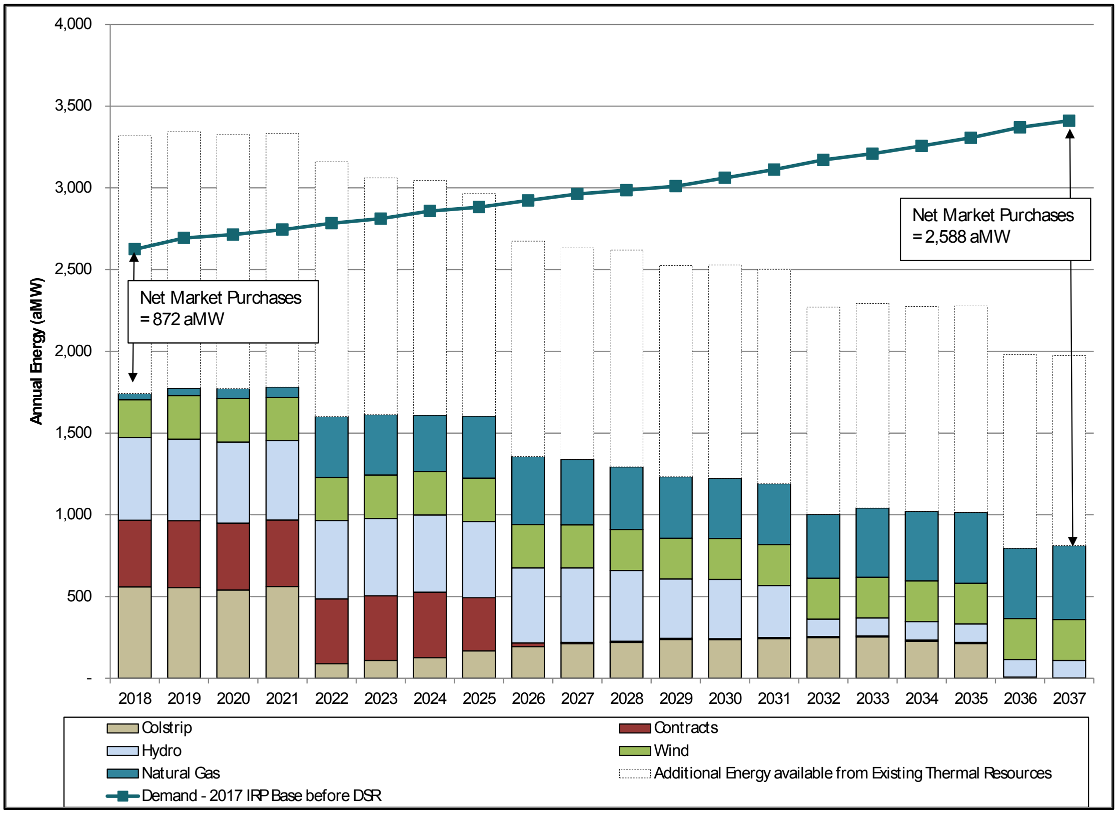
Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to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

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. This resource diversity is an important difference. In fact, on an average monthly or annual basis, PSE could generate significantly more energy than needed to meet our load, 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 economic; 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 wind to meet the energy need.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2017 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions.[3] The dashed box at the top indicates the total energy available from PSE's thermal resources if they were run without regard to economic dispatch. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2025 to make wholesale market purchases unnecessary. The challenge for PSE is shaping that energy into peak hours. Should regional resource deficits in the future result in periods where market purchases were unavailable, PSE's thermal resources would be able to ramp up to minimize the number of non-peak hours that PSE customers were affected, but we would still face peak need constraints. This is why PSE has a peak capacity constraint, not an energy constraint.

3 / Wind in this chart shows more prominently in Figure 1-5 than in the peak capacity need chart, because this reflects the expected annual generation of wind, not just what can be relied upon to meet peak capacity needs.

Figure 1-2: Annual Energy Position, Economic Resource Dispatch from Base Scenario



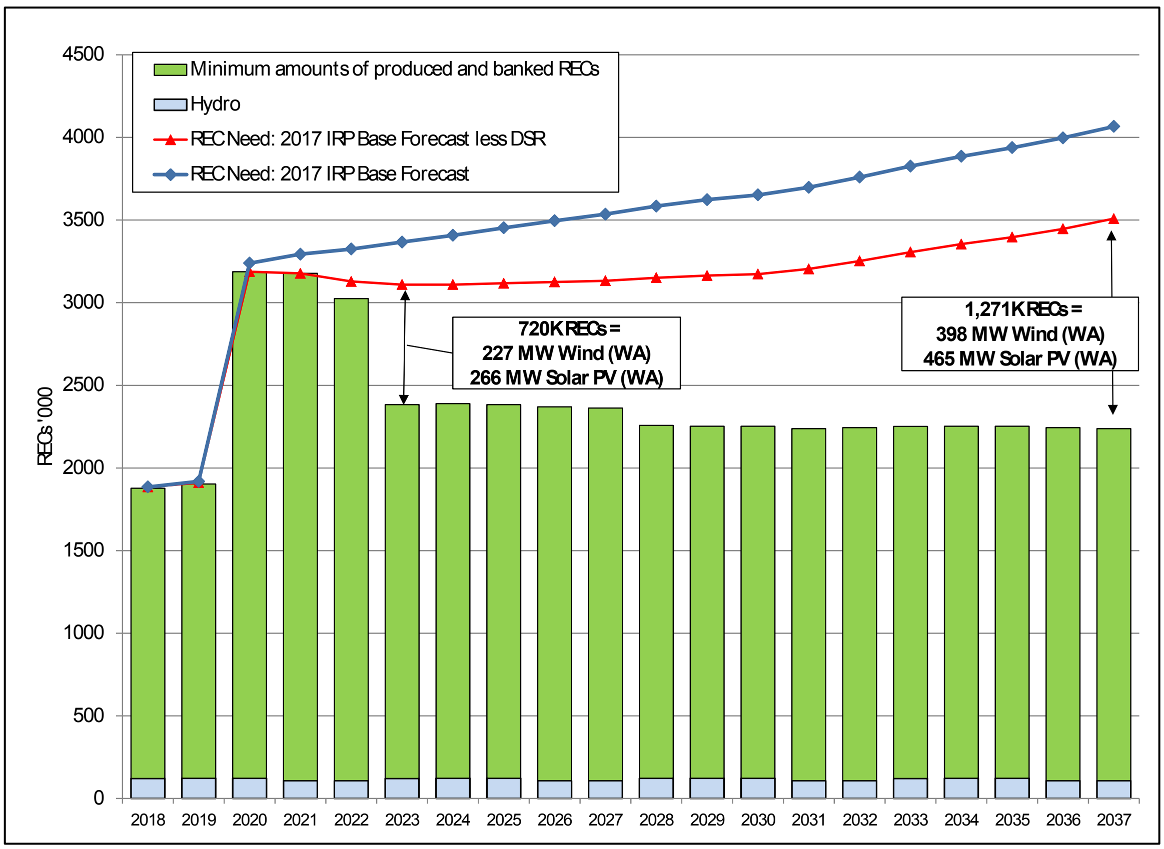
Renewable Need

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, 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 1-3 compares existing qualifying renewable resources with these targets, and shows that PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law until 2022. By 2023, PSE will need approximately 720,000 qualifying renewable energy credits. To put that need into context, it would equate to approximately 227 MW of Washington wind or 266 MW of eastern Washington solar power.[4]

4 / Slightly more MW of solar are needed because the annual output of solar in eastern Washington is slightly less than wind, so more MW of installed capacity are needed to generate the same quantity of energy in MWh.

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 its construction. Thus the project is expected to generate approximately 900,000 MWh per year of electricity, but 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 1-3: 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 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 1-4 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.”[5] It reflects the lowest reasonable cost portfolio of resources that meets the projected capacity, energy and renewable resource needs described above. Similar to prior IRPs, it accelerates acquisition of energy conservation and calls for additional demand response resources; however, it also includes significant changes. This IRP finds energy storage to be part of the lowest reasonable cost solution. It also finds that eastern Washington solar power may be more cost effective than wind. Additionally, it includes redirecting some firm transmission from existing wind resources to the Mid-C market in the resource plan forecast. Taken together, the “early” actions in this resource plan push the need to acquire additional fossil-fuel peakers out beyond 2024. This should not be interpreted to mean PSE *will* acquire new fossil fuel resources in 2025. Rather, this strategy provides a significant amount of time for technological innovations in energy efficiency, demand response, energy storage and renewable resources to develop, in the hope that additional fossil-fuel peaking generation plants will not be needed for our customers. Also, the resource plan shown here should not be interpreted as a statement of the ownership structure of resource additions; more accurately, it is a forecast of what technologies will appear cost effective in the future. For example, instead of PSE developing additional renewables or purchase power contracts, it may be lower cost and lower risk for customers to acquire unbundled RECs from independent power producers, who would then shoulder the technology and market price risk, instead of PSE’s customers.

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

Figure 1-4: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	266	378	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,912

Demand-side Resources (DSR): Energy Efficiency

This plan – like prior plans – includes aggressive, accelerated investment in helping customers use energy more efficiently. That is, significant changes in avoided cost had little impact on how much conservation 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 continue to find a ramp-up in demand response programs is part of the lowest reasonable cost portfolio. Demand response includes voluntary interruptible rate schedule programs for residential customers.

Renewable Resources

The timing of renewable resource additions is driven by requirements of RCW 19.285, as renewable resources still do not appear to be an effective or cost effective way to manage the financial risk of market exposure. This IRP found that eastern Washington solar power is expected to be more cost effective than wind from the Pacific Northwest or in Montana; however, costs between wind and solar are very close, especially in the first half of the planning horizon. As in prior IRPs, PSE's analysis shows we anticipate remaining comfortably below the four percent revenue requirement cap in RCW 19.285. PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law until 2022.

Energy Storage

This IRP finds energy storage, specifically flow batteries, to be a cost-effective part of the resource plan. While batteries are more expensive than peakers on a dollars per kW basis, batteries are more scalable, so they fit well in a portfolio with a small, flat need, as shown above in Figure 1-1 (Peak Capacity Need). Also, batteries provide more sub-hourly flexibility value than peakers, and this value is reflected in the IRP forecast.

Redirected Transmission to Market

In all future scenarios, redirecting 188 MW of BPA transmission from PSE's Hopkins Ridge and Lower Snake River wind facilities was shown to be part of the least cost solution. PSE will still be able to deliver the wind energy to our customers, but do so in a way that also helps to push the need for new generation into the future, which provides risk mitigation benefits as well. However, redirecting transmission and increasing PSE's reliance on wholesale market does entail financial and physical resource adequacy risk. Those risks were comprehensively examined in this IRP and determined to be manageable.[6]

Baseload Natural Gas Plants

The Pacific Northwest appears flush with renewable energy – hydro power, wind power and surplus solar power from California. Building additional baseload gas plants in PSE's service territory appears cost effective under only a few unlikely scenarios. Therefore, the resource plan includes no baseload gas plants.

Peakers

Beyond 2025, dual fuel peaking units appear to be the most cost-effective resource to meet larger capacity resource needs. These are units that can run off either natural gas, fuel oil or a blend of both. These peakers act as a low cost insurance policy, in case they are needed to meet loads due to extremely cold weather conditions, when another unit experiences a forced outage, or very low regional hydro conditions. A key reason why these units are so cost effective, is that backup fuel oil tanks negate the need for firm natural gas pipeline capacity. The resource adequacy implications of relying on peakers with backup fuel were examined rigorously in this IRP. The analysis shows the reliability risk of relying on backup fuel is extremely low. While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional fossil-fuel plants of any kind in the future, dual fuel peakers appear to be the least cost resource in the later part of the planning horizon, except in unlikely scenarios where baseload natural gas plants appear cost effective.

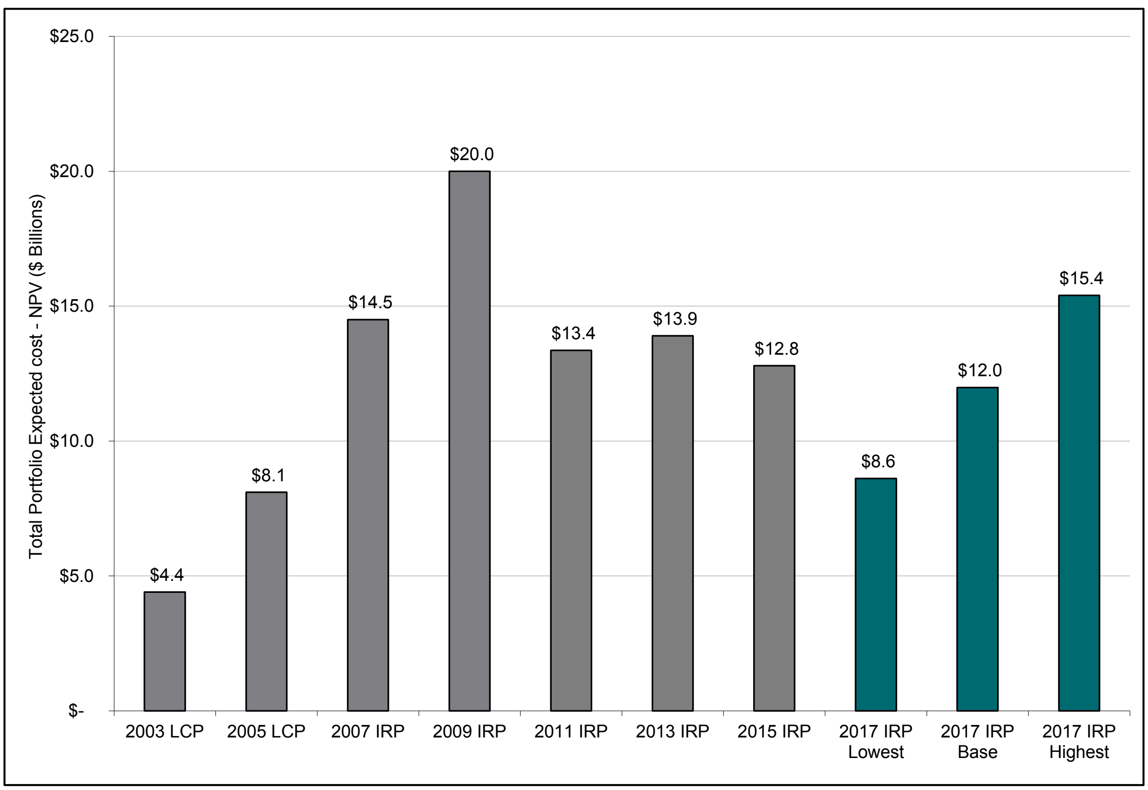
6 / See Appendix G, Wholesale Market Risk.

Portfolio Cost 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 potential carbon regulation. Figure 1-5 illustrates how incremental portfolio costs have changed over time, along with the context for the range of costs examined in this IRP. This figure shows the long-tem cost projection is down slightly from the 2015 IRP. This is primarily due to lower natural gas prices and lower capital costs for generation plants. Note that in this IRP, carbon costs on baseload natural gas and coal plants are applied across the entire WECC in the IRP Base Scenario assumptions, to simulate the effect of the Clean Power Plan if interstate carbon trading was adopted.

Figure 1-5: Incremental Portfolio Costs Over Time



Portfolio Carbon Emissions Associated with Electric Service

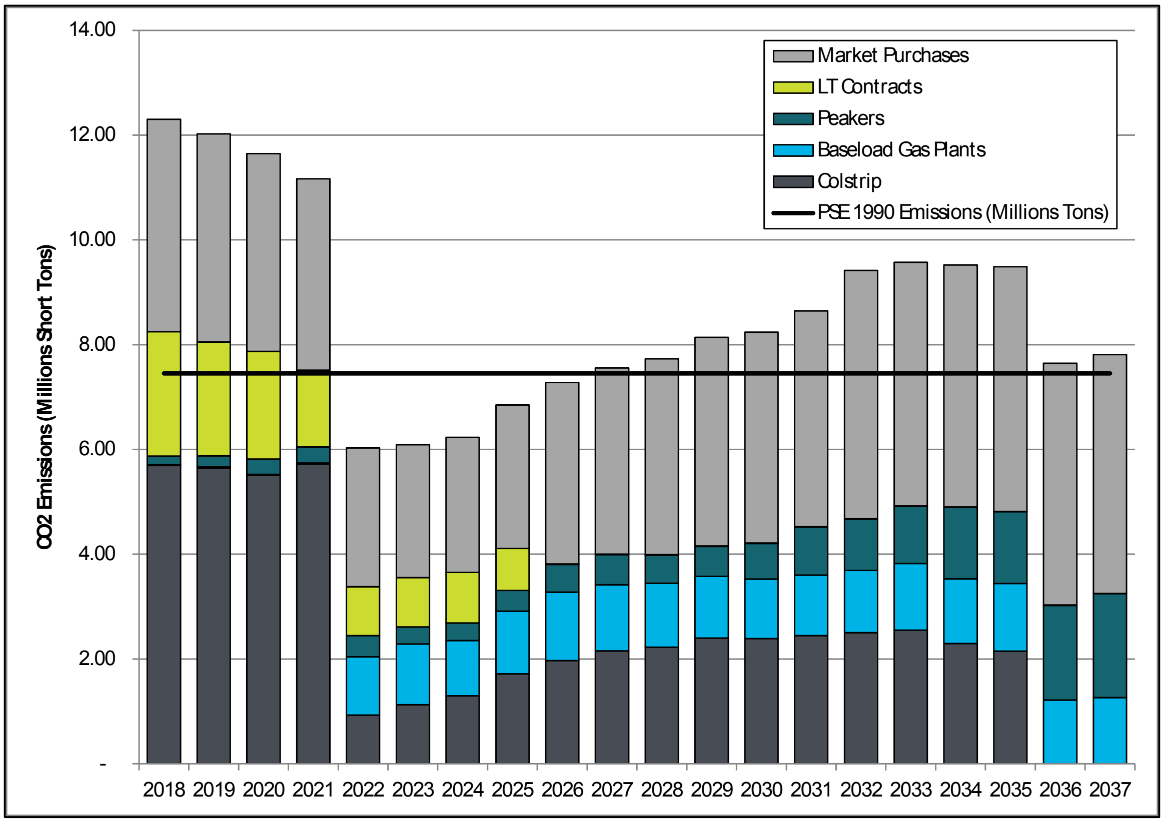
We are keenly aware of our customers' interest in reducing PSE's carbon emissions, and we share their concern and commitment to achieving meaningful carbon reduction that will mitigate climate change. Although PSE's portfolio carbon emissions can yield helpful insights, achieving the kind of results we all want will also require region-wide coordination as we continue this effort. The carbon emission profile presented in this section does not represent PSE's "preferred" outcome – we would prefer emissions to be lower. These emissions result from policies that require PSE to serve customers with the least cost combination of demand- and supply-side resources and carbon regulation policies that have been or may be enacted.

In estimating portfolio carbon emissions, PSE evaluates each of the resources in its portfolio. This is fairly straightforward when dealing with PSE-owned resources, but evaluating the wholesale market purchases that make up nearly a third of PSE's portfolio is more complicated because those purchases come from an integrated WECC-wide electric system. PSE's approach to addressing this carbon accounting issue is to calculate a WECC-wide average carbon intensity forecast in tons of CO_2 per MWh for each year in the planning horizon, and apply that average to market purchases. This is similar to the method used by the WUTC's compliance protocol, but that protocol uses the Northwest Power Pool average instead of the WECC average. Averages may satisfy reporting rules, but using an average emission rate is not appropriate for estimating how different policies or resource alternatives will affect greenhouse gas emissions. In reality, changes in emissions will be impacted by marginal resource decisions (i.e., which resources are being dispatched), not average resource dispatch. To understand how different factors will affect greenhouse gas emissions in total, one must examine impacts across the entire WECC. This kind of analysis is presented in Chapter 6 in the discussion on cost of carbon abatement.

Figure 1-6 illustrates the portfolio carbon emissions resulting from the resource plan forecast under the Base Scenario economic dispatch. The horizontal line shows PSE's estimated 1990 emissions. The stacked bars are the annual carbon emissions by resource type. The top of each stack does not represent direct PSE emissions – these are average emissions associated with market purchases. The rest of the stack relates directly to PSE resources or specific contracts. The first large drop in emissions occurs in 2022. This is caused by retirement of Colstrip 1 & 2, but also by the assumed implementation of a WECC-wide carbon price on coal and baseload gas plants, which significantly curtails the economic dispatch of Colstrip 3 & 4. From 2022 through 2034, direct emissions rise as natural gas prices increase relative to coal costs, causing the economic dispatch of Colstrip 3 & 4 to increase despite the WECC-wide carbon price. By 2037, PSE's direct emissions will be quite low, as all four units of Colstrip will have been retired – this drop would occur earlier if Colstrip 3 & 4 were retired sooner.

While this chart appears to show PSE's emissions will be in line with 1990 emissions by 2035, this is misleading. The Base Scenario assumes the most important and most difficult policy change is enacted in 2022 – the imposition of a WECC-wide carbon market. Policy makers, environmental advocates and those concerned about greenhouse gas emissions (including PSE) should not be comforted by this chart.

Figure 1-6: Projected Annual Total PSE Portfolio CO_2 Emissions and Savings from Conservation



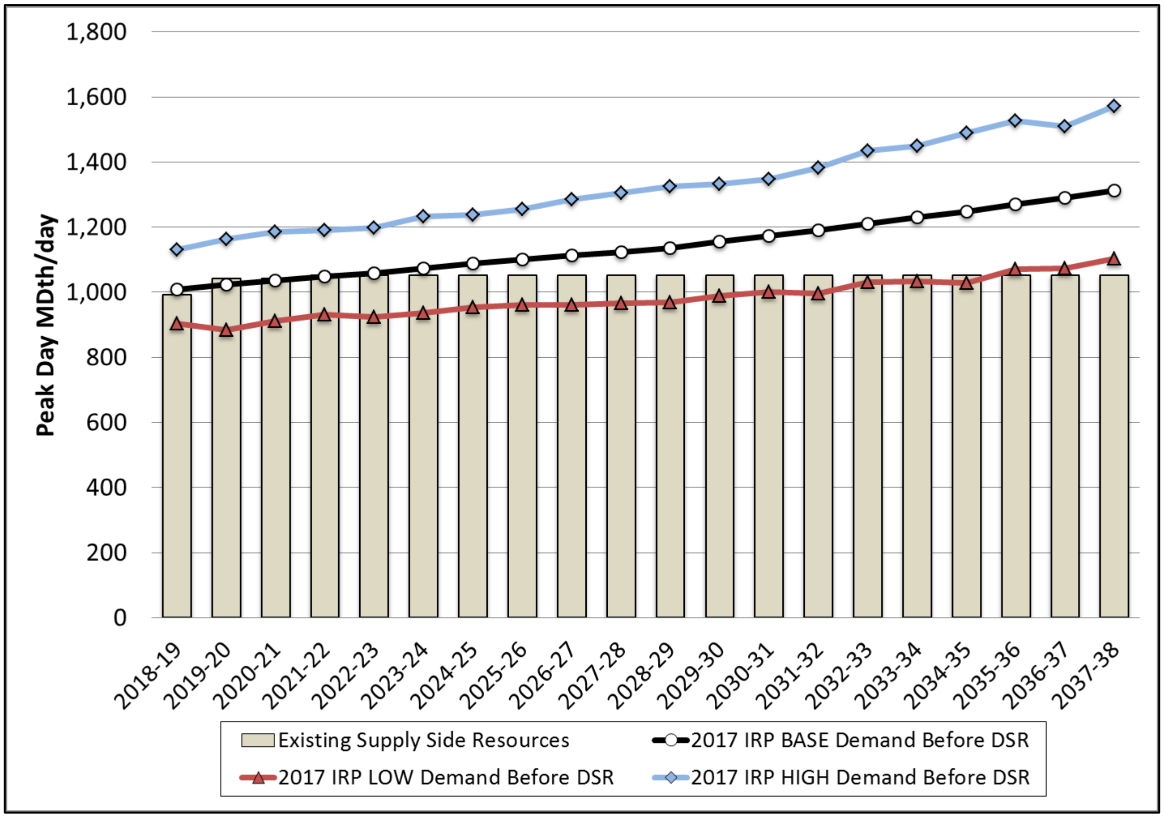
4. NATURAL GAS SALES RESOURCE PLAN FORECAST

PSE develops a separate integrated resource plan to address the needs of more than 800,000 retail natural gas sales customers. This plan is developed in accordance with WAC 480-90-238, the IRP rule for natural gas utilities. (See Chapter 7 for PSE's gas sales analysis.)

Gas Sales Resource Need – Peak Day Capacity

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 1-7 illustrates the load-resource balance for the gas sales portfolio. The chart demonstrates PSE has a small resource need in 2018, but the LNG storage facility in Tacoma is expected to come online for the 2019/20 heating season, which will meet the peak capacity needs of our customers until the winter of 2023/24. The 2018 need can be met with a one-year capacity contract on Northwest Pipeline, rather than investing in a long-lived resource to meet need for a single year.

Figure 1-7: Gas Sales Design Peak Day Resource Need



Gas Sales Resource Additions Forecast

Figure 1-8 summarizes the gas resource plan additions PSE forecasts to be cost effective in the future in terms of peak day capacity and 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 1-8: Gas Resource Plan Forecast, Cumulative Additions in MDth/Day of Capacity

	2025/26	2029/30	2037/38
Conservation (DSR)	27	49	84
Swarr	30	30	30
LNG Distr Upgrade	0	16	16
Additional NWP + Westcoast	0	53	133

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.

Swarr Upgrade

This IRP finds that upgrading the Swarr LP-Air facility's environmental safety and reliability systems and returning its production capacity to Swarr's original 30 MDth per day capability would be a cost effective resource as early as the 2024/25 heating season. 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. Upgrading Swarr is a short lead time project that is totally within PSE's control (it does not require the regional coordination needed for large, mainline pipeline expansion) so the project also adds strategic agility to the resource plan. If needed sooner, PSE could move quickly to upgrade Swarr, and if need is delayed, PSE could defer the upgrade. In either circumstance, the upgrade would put off the need for large, long-lived mainline pipeline expansions.

PSE LNG Distribution Upgrade

The PSE LNG peaking facility currently under construction in Tacoma allows the company to withdraw gas from the storage tank and deliver it directly into PSE's local distribution system. This upgrade is not an expansion of the LNG facility itself, but an expansion of the distribution network's capacity east of Tacoma that will allow more gas to flow from the LNG facility into PSE's gas supply network. The analysis forecasts that this will be needed and cost effective by the 2027/28 heating season. As with Swarr, this resource provides the portfolio with the strategic agility to determine timing based customer need as it develops.

Northwest Pipeline/Westcoast Expansion

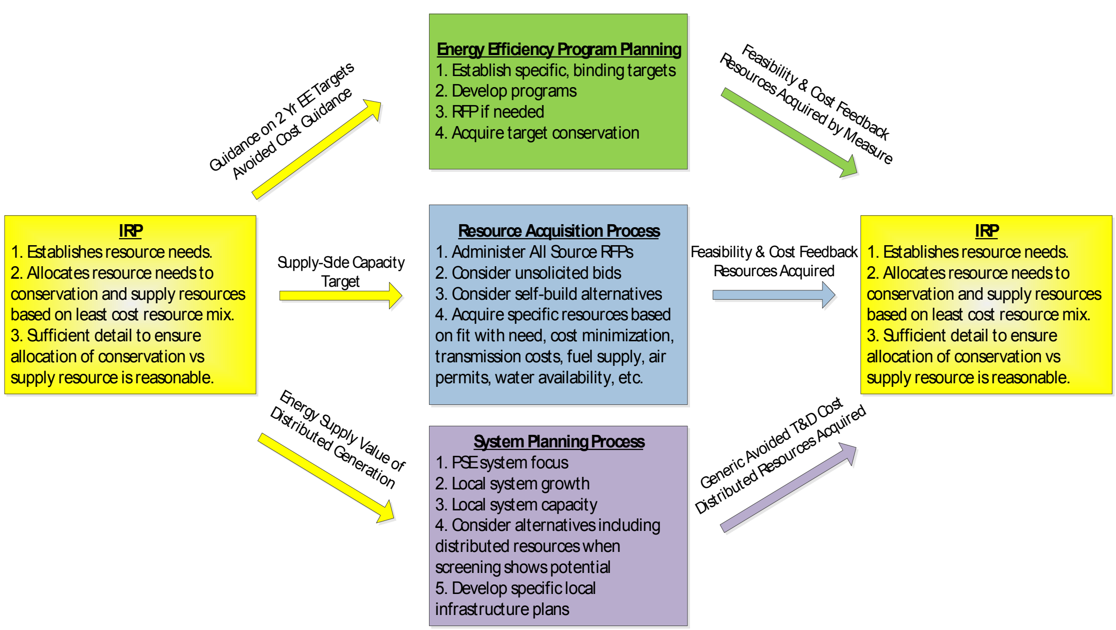
Additional transportation capacity from the gas producing regions in British Columbia at Station 2 south to PSE's system on the Westcoast pipeline is also forecast as cost effective beginning in the 2029/30 heating season.

5. 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 1-9 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 1-9 also illustrates that information from the IRP provides information to the local infrastructure planning process.

Figure 1-9: Relationship of IRP to Resource Decision Processes



2

2017 PSE Integrated Resource Plan

Resource Plan Decisions

This chapter summarizes the reasoning for the additions to the electric and gas resource plan forecasts.

Contents

1. OVERVIEW

The resource plan forecast 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]

The resource plan forecast described here is not simply the output of a deterministic portfolio optimization model. It incorporates what we learned from the deterministic analysis of how different long-term economic conditions and other factors affect risk across scenarios, from a stochastic portfolio analysis that includes consideration of how short-term variability impacts risk, and from the application of judgment given a qualitative assessment of the market in which we operate, which is more complex than can be simplified to a mathematical model. First, this chapter summarizes resource additions in the resource plan forecast. Then we present a high-level summary of the findings from the deterministic optimization analysis and stochastic portfolio risk analysis. Finally, after establishing context from the analysis, we step through each element of the resource plan to explain how judgment was applied.

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.

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

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 2-1 summarizes the forecast of resource additions to the company's electric portfolio that resulted from the 2017 IRP analysis. Most notably, this resource plan postpones the need for new thermal peaking plants out to 2025. We accomplish this by accelerating conservation investments, acquiring demand response, redirecting transmission to market, and using energy storage in the first seven years of the study period. This pushes fossil fuel peaking plant additions out into the realm of hypothetical resources. The further into the future that the need for such plants can be pushed, the better the chances are that technological innovations will reduce the relative cost of energy storage, conservation and demand response, such that development of new dual-fuel peaker plants will continually be pushed into the future. And, as the need for new resources gets pushed out, it gives the region more time to continue heavy investments in conservation, which will continue to improve the reliability of market purchases.

Figure 2-1: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	265	377	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,195

Portfolio Optimization Results across Scenarios

PSE examined 14 different market scenarios. The scenarios included different combinations of load, gas/power prices, and carbon costs/forms of regulation. Each scenario is a unique combination of factors that could affect market power prices or load. Scenario analysis is an important form of risk analysis. It helps us understand how specific assumptions that represent very different futures would affect the least-cost mix of resources. Figure 2-2, below summarizes the relationship between these scenarios and sensitivities. Additional detail is provided in Chapter 4.

Figure 2-2: 2017 IRP Scenarios

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

NOTES
1. Washington CAR (Clean Air Rule) regulations apply to both electric and gas utilities. These are applied to all scenarios.
2. Federal CPP (Clean Power Plan) regulations affect only baseload electric resources, so the gas portfolio models scenarios 1 through 11 only. CPP rules are modeled as if the entire WECC is part of an integrated carbon market, with carbon prices applied to all baseload generation, so that even if the CPP is ultimately not put into effect, the analysis still represents a form of carbon price regulation.
3. Carbon regulations are assumed to transition from CAR to CPP in 2022.

Figures 2-3 and 2-4 summarize 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. The scenario risk examined in this IRP includes a wide range of different kinds of carbon regulations, load growth assumptions and natural gas prices, which drive wholesale power prices.

That is, Figures 2-3 and 2-4 summarize the least-cost solution across all the market scenarios that were examined. 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 Figures 2-3 and 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 redirecting transmission, demand side resources, energy storage, renewables and dual-fueled peakers to meet remaining capacity needs. 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 2-3: Resource Builds by Scenario, Scenarios 1-9
Cumulative Additions by Nameplate (MW)

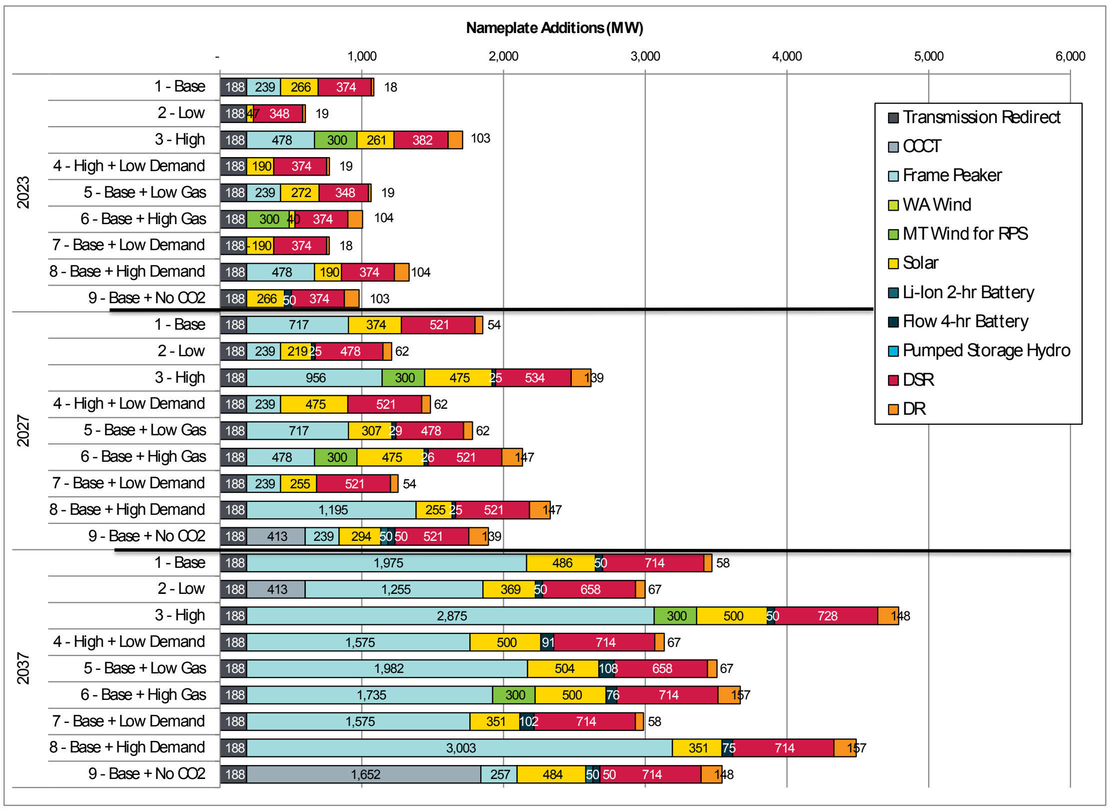
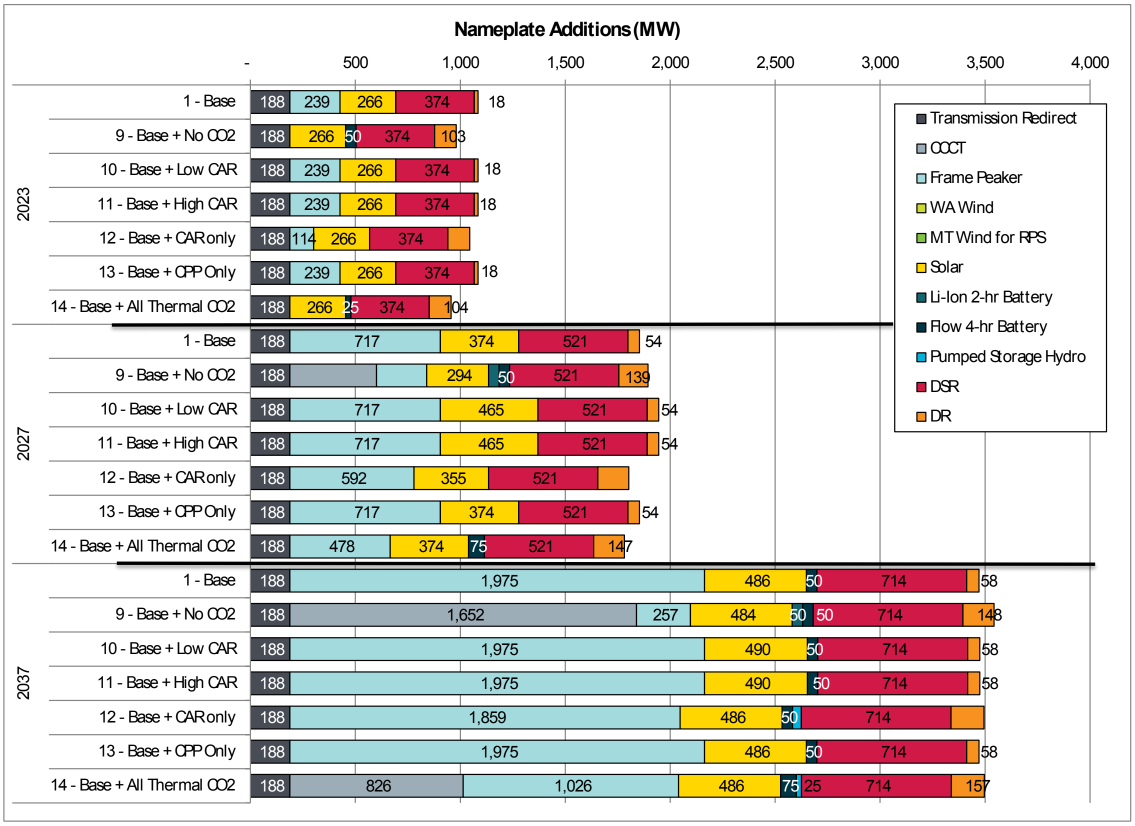


Figure 2-4: Resource Builds by Scenario, Scenarios 9-14
Cumulative Additions by Nameplate (MW)



Portfolio Optimization Results by Resource Type

Conservation

Cost-effective conservation does not vary across scenarios. This is consistent with findings in prior IRPs, where the variability in costs across scenarios has little impact on the amount found to be cost effective, which highlights it is a low-risk resource with regard to possible changes in carbon regulation, load growth and gas market conditions across the 14 scenarios and sensitivities examined.

Demand Response

All scenarios have at least 60 MW of demand response, with a few scenarios having as much as nearly 160 MW. In the context of a portfolio that needs over 3,000 MW of resources by 2037, this is a small degree of variability.

Redirected Transmission

Increasing market reliance by redirecting 188 MW of transmission from Hopkins Ridge and Lower Snake River is least cost across all scenarios and sensitivities, meaning it is a low-risk long-term decision from a deterministic risk perspective. Increasing market reliance could have risks that would be unseen in a deterministic analysis; these must be examined from a stochastic perspective.

Energy Storage

A small amount of utility-scale batteries appears cost effective at some point in the planning horizon in every scenario, given the assumed transmission and distribution benefits. By 2037, all scenarios have at least 50 MW, while a few have approximately 100 MW. It appears batteries are cost effective primarily because they can be sized to fit needs with slowly growing loads, in addition to being very flexible.

Renewable Resources – Eastern Washington Solar

Solar appears to be the most cost-effective renewable resource to comply with RCW 19.285, given the assumed transmission costs. PSE spent considerable resources refining our wind data, only to find solar appears more cost effective, so this was an unexpected shift. Solar provides no peak capacity value to PSE, because we are a winter peaking utility. The sun rises after PSE's system peaks on winter mornings and sets before our winter peaks begin in the afternoon. Despite the fact that solar had no peak capacity value, it still appears to be the least cost renewable resource for compliance with RCW 19.285. Figure 2-5 illustrates that the levelized cost of solar, even if it required transmission, is lower than Montana or Pacific Northwest wind. However, this figure shows the levelized costs including peak capacity value are close. Actual bids in an RFP process could yield a different conclusion.

Renewable Resources – Montana Wind

Wind in eastern Montana would not be a qualifying renewable resource under RCW 19.285, unless it were delivered all the way to Washington state on a real-time basis without shaping or storage. In this IRP, we examined whether being designated as a qualifying renewable resource would make Montana wind appear cost effective. It did not. However, Montana wind was reasonably close to being cost effective, as shown in Figure 2-5, below. In the acquisition process where actual projects are bid to the company and depending on the transmission costs, it is possible that PSE will find Montana wind projects could be more cost effective than Washington solar projects. However, there are three key barriers to Montana wind being designated an eligible renewable resource under RCW 19.285.

1. **TRANSMISSION STUDY PROCESS**. Montana wind would have to be scheduled into Washington state on a real-time basis without shaping or storage in order to qualify as a renewable resource under RCW 19.285. Being able schedule wind from Montana all the way to Washington state in this manner would require coordination of transmission studies across Northwestern, BPA and possibly the WECC. Recently, BPA scheduled a workshop in December 2017 in Montana to begin discussion about issues relating to transmission for Montana resources. For the region to move forward on this question is an optimistic step. A blanket policy that ensured wind from Montana could be "dynamically scheduled" to Washington without the need to do transmission studies on a project-by-project basis would avoid the issue described below about who pays for such studies. PSE supports addressing the challenges concerning transmission of Montana wind resources and will participate in BPA's workshop and other regional discussions on this issue.

2. **CHALLENGES WITH PROJECT-BY-PROJECT DETERMINATION – TIMING AND WHO PAYS.** Incentives may not be aligned to facilitate completion of studies for individual projects. Montana wind developers may be reluctant to pay for such studies without knowing that PSE would purchase the resource if it was determined to be a qualifying resource. If the study did not support dynamic scheduling capability, or if the costs to facilitate dynamic scheduling were significant, the resource would have no value to Washington state utilities as a renewable resource under RCW 19.285. PSE would also be reluctant to pay for these studies based on incentives created under current regulatory policies. For example, if PSE paid for such studies, we may not be allowed to recover the cost of the study if it did not directly lead to a resource acquisition (via PPA or ownership). Had this IRP found RPS-eligible Montana wind to clearly be a least-cost resource, the prudence risk associated with paying for such study might be reasonable – but that conclusion was not supported by the analysis. In addition, timing during the acquisition process could also be a challenge. If PSE has the choice of two resources that are very close in cost but one clearly meets eligibility requirements of RCW 19.285 while the other requires additional study to make that determination, it may not make sense to expose PSE's customers to that risk. The study could take several months, and should it determine the Montana wind resource would not being a qualifying resource, the alternative opportunity may no longer be available.

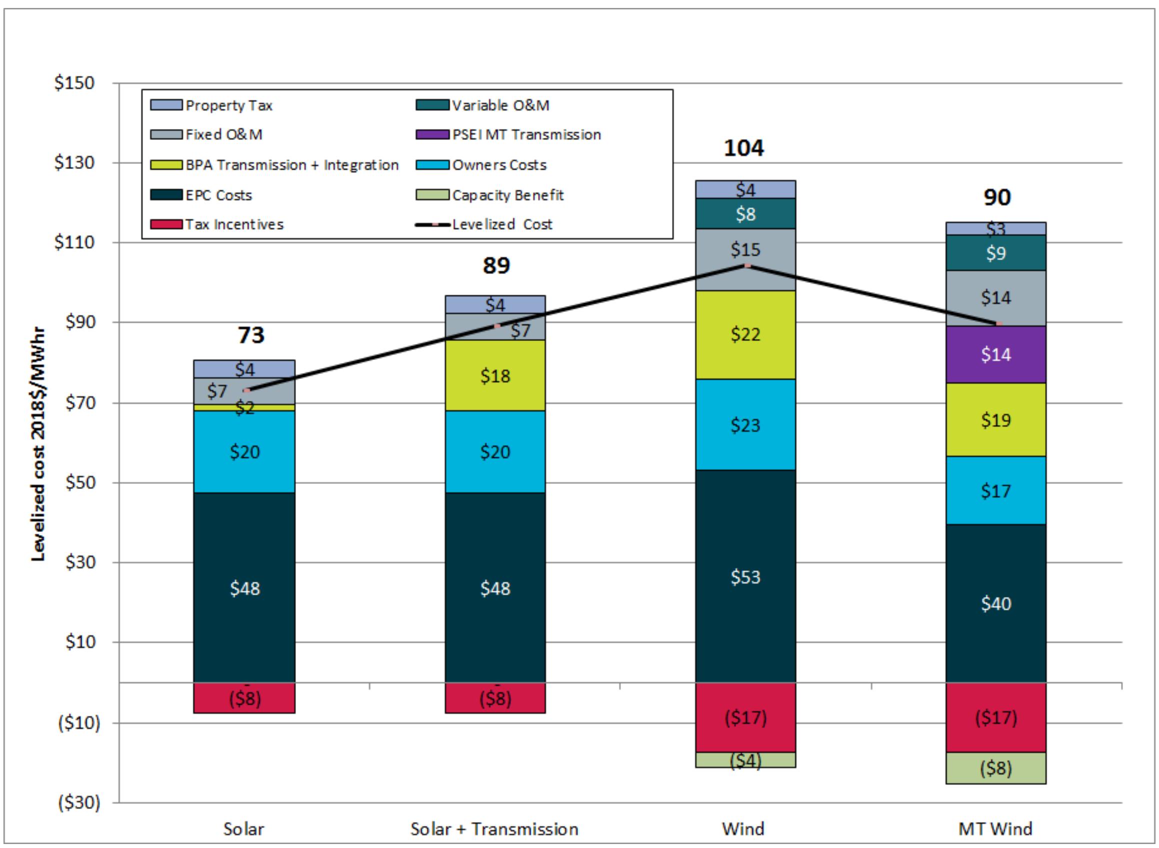
3. **DELIVERY TO PSE.** For Montana wind to have a peak capacity value, the resource must be delivered all the way to PSE. This IRP assumes additional transmission to PSE's

system is available at a price from BPA. However, that may not be the case. If the developer (or PSE) cannot obtain additional cross-Cascades transmission, the power may be delivered only to Mid-C. If PSE has to use existing transmission to Mid-C to transport that power to load, no capacity value is created at all. It simply offsets market purchases, since we have already counted on the transmission as a capacity resource. It is possible that contracts PSE uses to deliver energy from Colstrip to PSE could be used to deliver Montana wind. This topic will need to be explored more fully in future studies.

Pacific Northwest Wind

Wind in the Pacific Northwest did not appear to be a cost-effective resource in any scenario. Solar has lower costs and Montana wind has greater value because of the higher capacity factor and higher peak capacity value. As with Montana wind, this IRP assumes additional cross-Cascades transmission will be available at a price. If additional cross-Cascades transmission cannot be acquired, there will be no peak capacity value associated with Pacific Northwest wind – just like Montana wind. However, Figure 2-5, below, illustrates the levelized cost of solar, Montana wind, and Pacific Northwest wind are all fairly close – assuming Montana wind could qualify as a renewable resource.

Figure 2-5: Wind and Solar Cost Components



Baseload Gas Plants

Combined-cycle natural gas plants do not appear cost effective in most scenarios. Scenario 2 (Low) has 413 MW and Scenario 9 (Base + No CO_2) has over 1,650 MW. Both of these scenarios essentially have no long-term carbon pricing. The pricing in Scenario 14 (Base + All-thermal CO_2) on all thermal plants shows just over 800 MW of baseload gas plants being added. This highlights that the way carbon regulation will be implemented is important. In scenarios where carbon regulation primarily affects baseload gas plants but not peakers, baseload gas plants are not cost effective. The only two carbon regulation rules currently on the books that may affect PSE's operations – the CAR[2] and the CPP – generally affect baseload gas plants, but not peakers.

Peakers

Dual fuel frame peakers were found cost effective in every scenario. Most scenarios show it as the go-to capacity resource later in the planning horizon, with at least 1,000 MW by 2037. The only exception is in Scenario 9 (Base + No CO_2), which has only 257 MW of dual fuel peakers – but it seems unlikely there will be no carbon regulation of any kind. In many scenarios, carbon regulation is applied unevenly – to baseload gas but not peakers. This tends to increase the value of peakers relative to other capacity resources, such as energy storage and demand response. This can be seen by comparing energy storage and demand response in the Base Scenario and Scenario 13 (the CPP Only Scenario), which impose carbon costs on baseload gas plants but not peakers, with the results from Scenario 9 (Base + No CO_2) and Scenario 14 (Base + All Thermal CO_2), which treat peakers and baseload gas plants equally with respect to carbon pricing. The two scenarios with uneven application of carbon pricing (1 and 13) show about 60 MW of demand response would be cost effective by 2037, but scenarios with consistent application of carbon regulation (9 and 14) find about 150 MW of demand response cost effective. Application of carbon costs only on baseload gas also reduces the amount of energy storage. Scenarios 1 and 13 (carbon costs only on baseload plants) have 50 MW of energy storage as least cost, compared to 100 MW in scenarios 9 and 14 (consistent application of carbon costs to all resources).

2 / Under the CAR, peakers are not exempt, but they also do not dispatch enough to hit the limits that would trigger compliance. For this IRP, PSE capped run times for new peakers to ensure they would not hit the emission triggers under CAR, so that we would avoid inflating the economic value of dispatching peakers.

Adequate backup fuel oil makes peakers significantly less costly than baseload gas plants. Baseload gas plants require firm pipeline capacity in lieu of backup fuel. Firm pipeline capacity is expensive relative to a fuel-oil storage tank. The firm pipeline cost for a 300 MW baseload gas plant would be about $20 million per year. An oil tank for a 300 MW peaker would be a one-time cost of about $15 million. There is a reliability concern with extensive reliance on dual fuel peakers. That is, will the backup fuel inventory be adequate? In this IRP, we present a comprehensive analysis demonstrating 48 to 72 hours of backup fuel supply would be adequate, even if PSE added several hundred MW of dual fuel peakers.

Summary of Stochastic Portfolio Analysis

The deterministic scenario analysis described above is helpful in understanding how changes in key assumptions would affect the least-cost mix of resources. It is not, however a complete picture of risk. The deterministic analysis assumes perfect foresight, so we know what factors – such as natural gas prices or carbon policies – will be far in advance of having to make decisions. It also assumes all markets and weather conditions are “normal.” In reality, we do not know what natural gas prices will be, what hydro or wind conditions will be, or what kinds of carbon regulation will be imposed by 2025. To examine the implications of these risks, we develop a number of portfolios and run them through 250 simulations (or draws)[3] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 regulations/prices. From this analysis, we can observe how costs change across portfolios and identify whether differences occur when risk is analyzed.

We chose eight different portfolios to test in the stochastic analysis. The portfolios examined in this analysis were designed to test whether different resource alternatives would have a significant impact on expected cost or risk. PSE defines “risk” as the TailVar90 metric – which we adopted from the NPCC several years ago. That is the average value of all observations above the 90th percentile in the distribution of costs. TailVar90 of revenue requirement is a clear risk metric. It specifically focuses on how bad portfolio costs could be over the planning horizon. It allows us to see how different resources would affect bad outcomes. The portfolios tested included the following.

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

1. **BASE SCENARIO.** This is the least cost mix of resources that resulted from the Base Scenario. the primary capacity resources after conservation are dual fuel peaking units.
2. **RESOURCE PLAN.** The resource plan relies on additional demand response and batteries to push out the first dual fuel peaker to 2025.
3. **BASE + NO CO_2.** This was the least cost mix of resources that resulted from the Base + No CO_2 Scenario. It includes 1,652 MW of baseload gas plants by the end of the planning horizon.
4. **NO ADDITIONAL DSR.** This is the least cost portfolio in the Base Scenario, if we did not consider any additional DSR. The purpose is to illustrate the impact of conservation on both cost and portfolio risk.
5. **ADD 300 MW OF SOLAR.** This portfolio adds 300 MW of solar beyond RPS requirements in 2022 to the least cost portfolio from the Base Scenario. Solar was chosen because it was found to be the least-cost renewable resource across all scenarios. Adding solar would avoid exposure to market purchases if prices run up – though it also reduces the ability to take advantage of low prices. The purpose is to examine whether adding solar beyond requirements would reduce portfolio risk, and if so, would it reduce risk enough to justify the cost of including more in the resource plan.
6. **NO TRANSMISSION REDIRECT.** To develop this scenario, we excluded the transmission redirect as a resource choice, and re-optimized the portfolio, which added more peakers. However, increasing PSE's reliance on firm transmission backed by short-term market purchases could also increase risk. Even a dual fuel peaker could mitigate risk of very high power prices. This analysis was performed to test whether the transmission redirect that was chosen as low cost in every scenario would create unreasonable risk exposure.
7. **NO NEW THERMAL RESOURCES.** This is the least-cost portfolio from the No New Thermal Resources portfolio sensitivity, which was developed in the Base Scenario. When no new thermal resources were allowed, pumped hydro storage became the go-to capacity resource. The deterministic analysis showed it was expensive; this analysis is to determine if reducing exposure in high market cost conditions justified the high cost of pumped hydro.
8. **MORE CONSERVATION.** This portfolio adds 70 aMW of energy efficiency which provides an additional 4 MW of capacity, to explore whether an incremental increase in conservation would reduce portfolio risk, and if so, whether the reduction would justify adding conservation beyond what was found to be least cost.

Summary of Stochastic Portfolio Results

KEY FINDING. Resource additions have little impact on portfolio risk. This is primarily because the portfolio is already quite large – 6,000 MW today – and what's being added to it is small. The resource plan forecast calls for approximately 2,750 MW of resources by 2037. However, only 1,150 MW of those resources reduce exposure to wholesale natural gas or power market risk – namely, conservation and solar. While we can examine cost versus risk of individual resources, aggregated up to the portfolio level, additions are small in relation to the portfolio. The take-away is that resource additions do not appear to be a meaningful way to try and manage portfolio risk. Instead, natural gas price and wholesale power price risk needs to be financially managed in the shorter-run – which is exactly what PSE does.

Results Across Portfolios Tested

There were some differences between the mean, or expected costs, of the various portfolios and the TailVar90 risks. Some are intuitive, others are not, and will be explained in the following discussion. Figure 2-6, below, summarizes results of the stochastic analysis. The mean, or expected values, from the stochastic analysis are relationally the same as results of the deterministic analysis. That is, the deterministic analysis showed the optimal Base Scenario portfolio was slightly lower cost than resource plan. We see the same in the stochastic analysis. All the other scenarios show expected portfolio costs greater than the resource plan forecast.

Figure 2-6: NPV of Portfolio Cost Metrics – Costs are NPV $Millions

	"Average" Conditions			Worst Conditions		
NPV ($Billion)	**Mean**	**Difference from Base**	**% Change**	**TVar90**	**Difference from Base**	**% Change**
1 – Base Scenario Portfolio	10.52			11.79		
2 – Resource Plan	10.57	0.05	0.5%	11.84	0.05	0.4%
3 – Base + No CO2 Portfolio	11.13	0.61	5.8%	12.5	0.71	6.0%
4 – No DSR	10.84	0.32	3.1%	12.8	.4	3.4%
5 – Add 300 MW Solar in 2023	10.54	0.03	0.3%	11.8	.01	0.1%
6 – No Transmission redirect	10.62	0.1	0.9%	11.89	0.1	0.8%
7 – No new thermal	12.69	2.18	20.7%	14.65	2.86	24.3%
8 – More conservation (Bundle 5)	10.81	0.29	2.7%	12.06	0.27	2.3%

Key Observations from Figure 2-6

RESOURCE PLAN COMPARED TO BASE SCENARIO PORTFOLIO. The resource plan includes more demand response and early batteries in order to delay the need for peakers until 2025, otherwise it is quite similar to the Base Scenario least-cost portfolio. The Base Scenario portfolio incorporates significant amounts of peaker units. The expected cost of the resource plan is slightly higher than the Base Scenario portfolio – by about 0.5 percent, or an NPV increase of $50 million over the planning horizon. Risk is also slightly higher: The mean of the worst 10 percent of cases (TailVar90) is higher by 0.4 percent. This illustrates that including more demand response and early batteries will not have a material effect on portfolio risk.

PEAKERS COMPARED TO BASELOAD GAS. A portfolio with baseload gas plant (CCCT) additions has an expected value significantly higher than the Base Scenario portfolio, which includes peakers instead of baseload gas plants. Substituting over 1,600 MW of baseload gas plants for peakers increases expected costs – by $610 million, a 5.8 percent increase. Risk increases as well, by about the same amount – 6 percent. This illustrates baseload gas plants do not reduce risk relative to peakers. Both substitute exposure to wholesale electric prices for exposure to wholesale natural gas prices. Both plants protect against market heat rate blow-outs, in which the price of electricity increases relative to natural gas prices. Focusing just on variable costs, baseload gas plants provide a better hedge against market heat rates because they use less natural gas. However, baseload gas plants come at a significantly higher initial cost. This risk analysis shows baseload gas plants provide no additional risk protection. Additional discussion on this issue appears below.

VALUE OF DSR. Conservation reduces both cost and risk relative to the alternative, which would be to add more dual fuel peaker capacity. The stochastic analysis demonstrates that cost-effective DSR saves $320 million on an expected value basis – a 3.1 percent savings. DSR also reduces risk, but not quite as much as it reduced cost. One might expect the risk reduction to be greater than the cost reduction, but there is an important difference between conservation and peakers. Conservation for PSE reduces exposure to gas and power prices by reducing load – typically winter loads – which avoids the need to build additional generation resources. Peakers represent an option to generate that can be exercised at any time. There may be circumstances in which summer market prices and heat rates are quite high. Conservation programs that primarily target heating loads have no value during those periods. Peakers, on the other hand, can provide value in the summer during times when natural gas and power prices diverge and capture margins that pass through to customers as an offset to power costs in rates. The analysis still shows conservation provides a significant reduction in risk.

ADDING 300 MW OF SOLAR. Adding solar beyond requirements of RCW 19.285 increases expected portfolio costs somewhat – by $30 million, or 0.3 percent. The additional solar also increases risk very slightly – by $10 million, or 0.1 percent. The much smaller reduction in risk means solar is reducing power costs during bad market conditions, but still not quite enough to offset the higher fixed cost. Also, something to consider is that solar output is lower in the winter when PSE's loads are highest, but solar output is higher in the summer, when prices can be high and volatile. Thus, the risk reduction is mostly a financial benefit, not a physical one – which is not a problem as we are trying to minimize costs of complying with RCW 19.285. With such close results, should PSE add solar to mitigate risk? That conclusion is not supported by this analysis. However, if solar costs continue to fall, it is possible that PSE will find solar reduces risk in future IRPs. Because PSE is winter peaking, we would need to develop planning standards to ensure such additions do not exceed loads so that PSE does not acquire more generation resources than our customers can use just so the surplus could be sold into the market.

INCREASING MARKET RELIANCE – IMPACT OF THE TRANSMISSION REDIRECT. The transmission redirect to access more short-term market energy is low-cost capacity. This comparison shows that if PSE did not pursue the transmission redirect, expected portfolio costs would be higher – by $100 million, or 0.9 percent. Risk would also be higher, again by $74 million, or 0.8 percent. The minor increase in risk means that an additional peaker would reduce variable power costs when power prices are high, but not enough to cover the higher cost. It is also interesting to compare the percentage change in risk from adding solar with the percentage change in risk from substituting a peaker for market purchases. Relative to cost, on a percentage basis solar performs as a better hedge because it avoids electric *and* natural gas price risk, whereas a peaker does not avoid the fuel price risk.

NO NEW THERMAL RESOURCES. This analysis illustrates that peakers are quite valuable to the portfolio. This portfolio covers much of the peak capacity need with pumped hydro storage as the most cost-effective alternative. This would be costly. The expected value is more than $2 billion higher than the Base Scenario portfolio, about a 20.7 percent increase. Risk is even higher, too – by over $2.8 billion, which is a 24.3 percent increase. This illustrates that energy storage does not effectively protect against natural gas price or power price risk. At best, energy storage allows for some short-term arbitrage between hours, but it is still charged with electricity, and therefore subject to the variability of market electric prices.

ADDITIONAL CONSERVATION. In this IRP we tested an increase in conservation beyond what was found cost effective across all scenarios. The deterministic analysis showed Bundle 3 was cost effective in every scenario. We included two additional bundles (through Bundle 5), which added 4 more MW of conservation and 68 aMW more energy savings. We tested this portfolio to determine if the additional conservation would reduce risk, and if so, whether the risk reduction benefits were worth the higher cost. Expected costs for this portfolio are $290 million higher than the Base Scenario portfolio, an increase of approximately 2.7 percent. The additional conservation did not, however, lower risk. Risk increased by $270 million (2.3 percent), meaning the higher cost of conservation was not offset by power cost savings, on average, in the worst 10 percent of simulations. While conservation that addresses heating loads is helpful for reducing peak capacity needs and reducing exposure to winter power and natural gas price risk, it provides no value outside the heating season. Peakers can help mitigate power price risk in the winter and present a year-round option to generate savings in excess of fuel costs that will flow back to customers.

Resource Plan Forecast: Application of Judgment

Discussion above summarizes key findings from the deterministic and stochastic portfolio analyses. These analyses do not necessarily drive an answer, but provide information upon which decisions can be made. While the models are comprehensive, there are risks and opportunities that are not reflected in the resource modeling. This section will step through each element of the resource plan and provide an explanation of why it is reasonable.

Increased Demand Response and Energy Storage: The Resource Plan Through 2024

Increasing demand response and energy storage, relative to the least cost mix of resources in the Base Scenario is an important risk mitigation decision. Technology is driving down the cost of alternative resources. Solar and energy storage appear cost effective for the first time in this IRP. While we do reflect improving technology costs in the portfolio analysis, it is possible energy storage costs will fall even faster than expected. Additionally, as we analyze additional kinds of demand response programs in the 2019 IRP, those could prove a cost effective way to avoid new fossil fuel generation. In addition to technology reducing cost of alternative resources, carbon regulation looms as a significant source of uncertainty. Even the form of carbon regulation is uncertain. The way carbon regulation is implemented is just as important as the per-unit cost of carbon. Additional demand response and batteries, sufficient to push the need for additional fossil fuel plants to 2025 or beyond is a reasonable strategy. This will provide time for technology to work on reducing alternative resource costs as well as time for carbon regulations to become clearer.

The specific amounts of additional demand response and energy storage were taken from the least cost portfolios under Scenario 9 (Base + No CO_2) and Scenario 14 (Base All-thermal CO_2). We substituted the early builds from these scenarios for the early peaker build from the Base Scenario, as shown in Figure 2-7. Both of those scenarios had sufficient demand response and energy storage to push the need for additional fossil fuel generation resources out to 2025. These scenarios have an unbiased application of carbon regulation, whereas the CAR and CPP in the other scenarios create an unintended bias that favors peakers over other capacity resources. In the Base Scenario, substituting demand response and energy storage increased NPV of portfolio costs by about $9 million – less than 0.1 percent. This is an insignificant cost to avoid building a fossil fuel plant that will have at least a 35-year life, to make sure it will be a good long-term investment on behalf of our customers.

Cost-effective Conservation

The same level of conservation was found cost effective across all the scenarios. This provides a high degree of confidence that we have the right amount of conservation in the resource plan. As described above, we tested adding more conservation to determine if it would provide a reasonable way to mitigate financial portfolio risk. It did not. Therefore, the decision on conservation is very well supported by both the deterministic and stochastic analysis.

Transmission Redirect

Similar to conservation, redirecting transmission to increase our firm access to short-term wholesale markets was least cost across all scenarios. This resource addition does cause some concern for PSE, as we already rely on a significant amount of firm transmission to access wholesale market. This transmission redirect clearly appears cost effective, but it is not without risk. One important risk is BPA operational/policy risk—it is possible that in the future, BPA may not facilitate this redirect. There are two other important risks to consider. One is physical resource adequacy risk. PSE performed a robust wholesale market risk analysis – one that is tied to the regional resource adequacy framework developed and implemented by the NPCC and BPA. This analysis shows wholesale market is nearly as reliable as a new peaker. The other risk is financial. The stochastic portfolio risk analysis confirms that increasing reliance on wholesale markets does increase risk. However, as described above, the increase in risk is reasonable, given the significant cost savings.

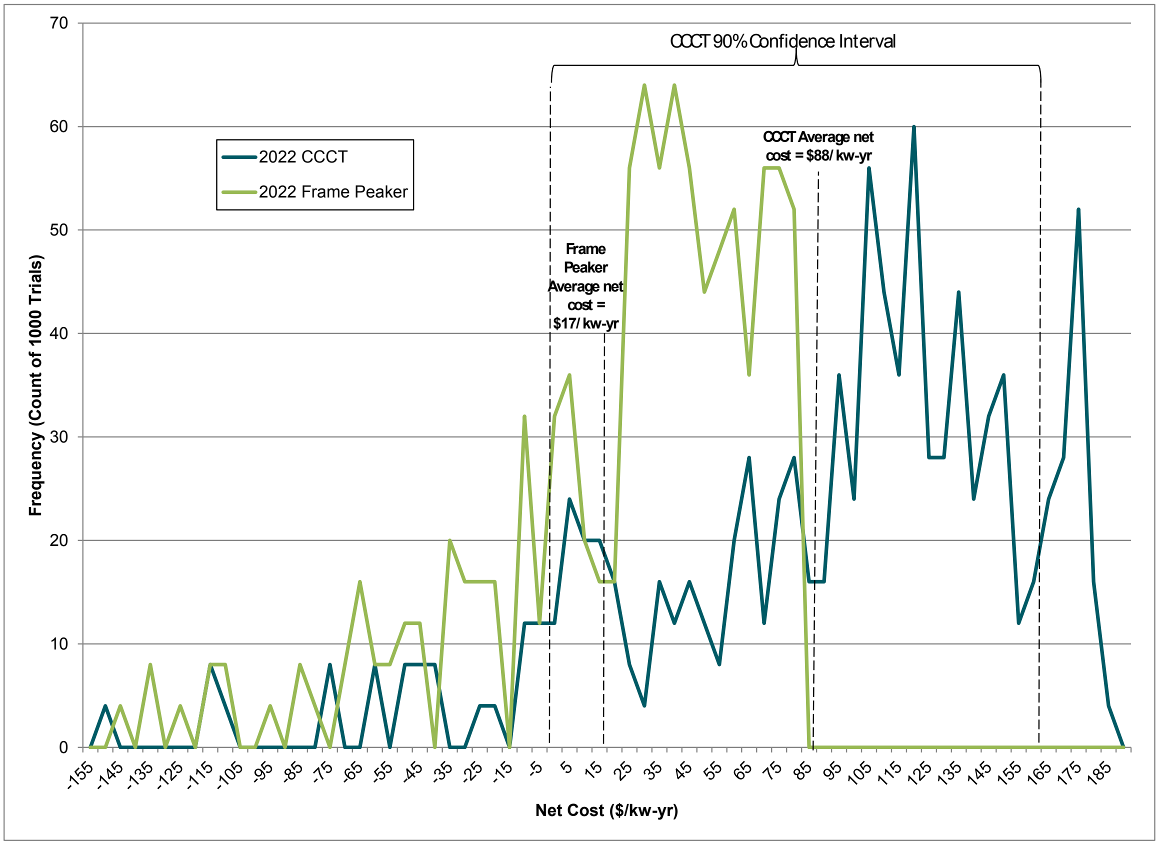
Renewables – Eastern Washington Solar

Every scenario showed eastern Washington solar was the most cost-effective qualifying renewable resource, so this is a very durable answer across all scenarios. While our base assumption had no transmission costs, it appears solar would be cost effective even if it required transmission – as shown above in Figure 2-5. The other primary qualifying renewable resource is wind in eastern Washington. While Montana wind was analyzed as if it were a qualifying resource, RCW 19.285 would have to be changed for that to be the case. Montana wind did not appear cost effective relative to eastern Washington solar, so the issue is resolved for this IRP. The stochastic risk analysis showed that solar beyond that needed for compliance with RCW 19.285 would reduce portfolio risk, but not sufficient to justify the up-front investment.

Peakers Instead of Baseload Gas Plants – Capacity Resources Later in the Planning Horizon

Dual-fuel peakers were found to be the least cost capacity resource in most scenarios. The exceptions were Scenario 9 (Base + No CO_2), which had 1,652 MW of baseload gas plants by 2035 instead of peakers, and Scenario 14 (Base + All Thermal CO_2), which had 826 MW of baseload gas plants instead of peakers. The stochastic analysis results in Figure 2-6 illustrated that baseload gas plants increased both cost and risk. While baseload gas plants use natural gas more efficiently and will be economically dispatched more often than peakers, the margin (market price – variable cost) is not sufficient to overcome the significantly higher fixed costs, both capital costs for the plant and firm pipeline capacity costs. Figure 2-7, below, shows the frequency distributions for the net cost of both peakers and baseload gas plants. “Net cost” means the revenue requirement of the plant (including recovery of both fixed and variable costs) minus the market value of the energy it generates. Each plant is economically dispatched for each hour, using the AURORA model, and this net cost is calculated for each simulation to create the distribution of net costs. This figure shows the expected value for net peakers is near the lower end of the baseload gas plant’s 90 percent confidence interval of net cost. There were some simulations where both kinds of plants created enough margin to offset the fixed costs. Notice the tail on the left for both plants is quite similar. This is because as power prices diverge from gas prices, both plants will capture increasing margins, though baseload plants will capture a bit more because they are more efficient. However, in general, the greater margins do not appear to overcome the higher fixed costs of the plants. On the other end of the distribution, baseload gas plants have net costs that go significantly higher than peakers. In fact, the *mean* net cost for baseload gas plants is $85/kW-yr, which is slightly higher than the *worst* case for a peaker, at just over $85/kW-yr.

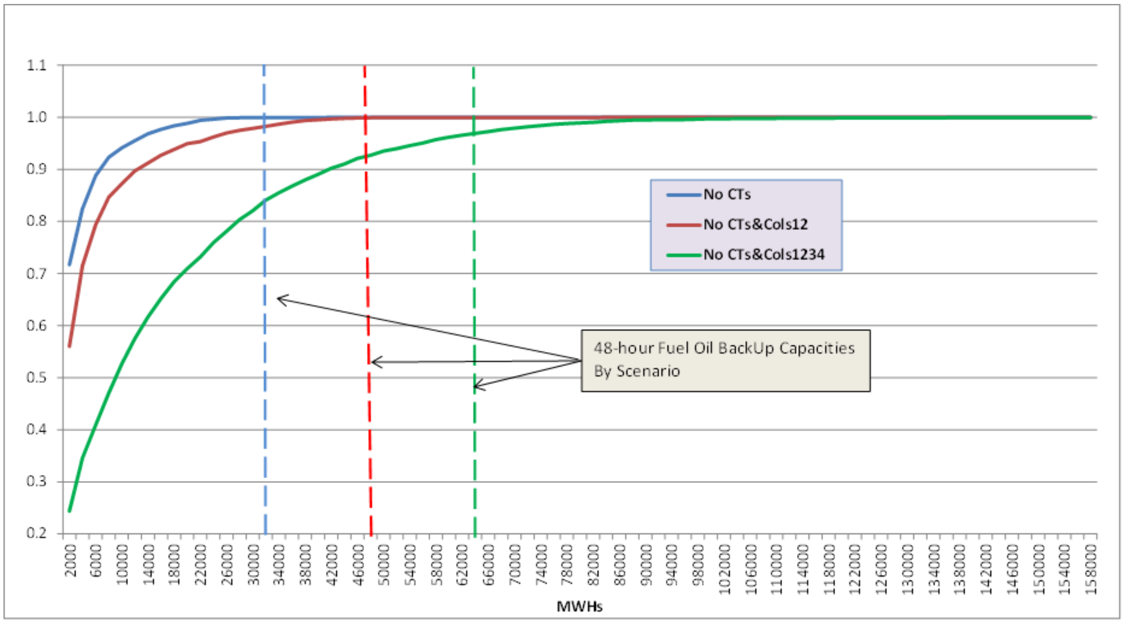
Figure 2-7: Comparison of Net Cost Distribution
Baseload Gas and Peakers with Oil Backup (in 2018 dollars per kW)



The other concern PSE has had with dual-fuel peakers is whether the backup fuel would be adequate. In this IRP, we examined whether backup fuel was sufficient for our existing dual fuel peaker generators and also examined implications of adding several hundred additional MW. We used our resource adequacy modelling framework to identify the number of hours in a year that we would physically need to rely on backup fuel. This was performed by first removing all peakers from the portfolio and calculating the number of hours the portfolio would be physically short. Then we also subtracted Colstrip 1 & 2 from the portfolio, followed by Colstrip 3 & 4. Figure 2-8 demonstrates that 48 hours of backup fuel was adequate to cover 100 percent of the needs for the existing fleet and new peakers when Colstrip 1 & 2 are retired. When we removed Colstrip 3 & 4 from the portfolio, 48 hours of backup fuel for the new and existing peakers would cover the need for approximately 95 percent of the simulations in the RAM. However, if the backup fuel tank were increased to 72 hours, that would cover 100 percent of the needs. Air permits to operate on backup fuel for 72 hours per year would probably not be a problem.

Therefore, PSE included dual fuel peakers later in the planning horizon – though we hope advances in energy storage will continue to push out the need for fossil fuel generation in all future IRPs.

Figure 2-8: Cumulative Distribution of Incremental Deficit for Bad Simulations in MWh/yr



3. 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. The years shown here reference the gas year, so 2025/26 means the gas year starting November 2025 through October 2026.

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

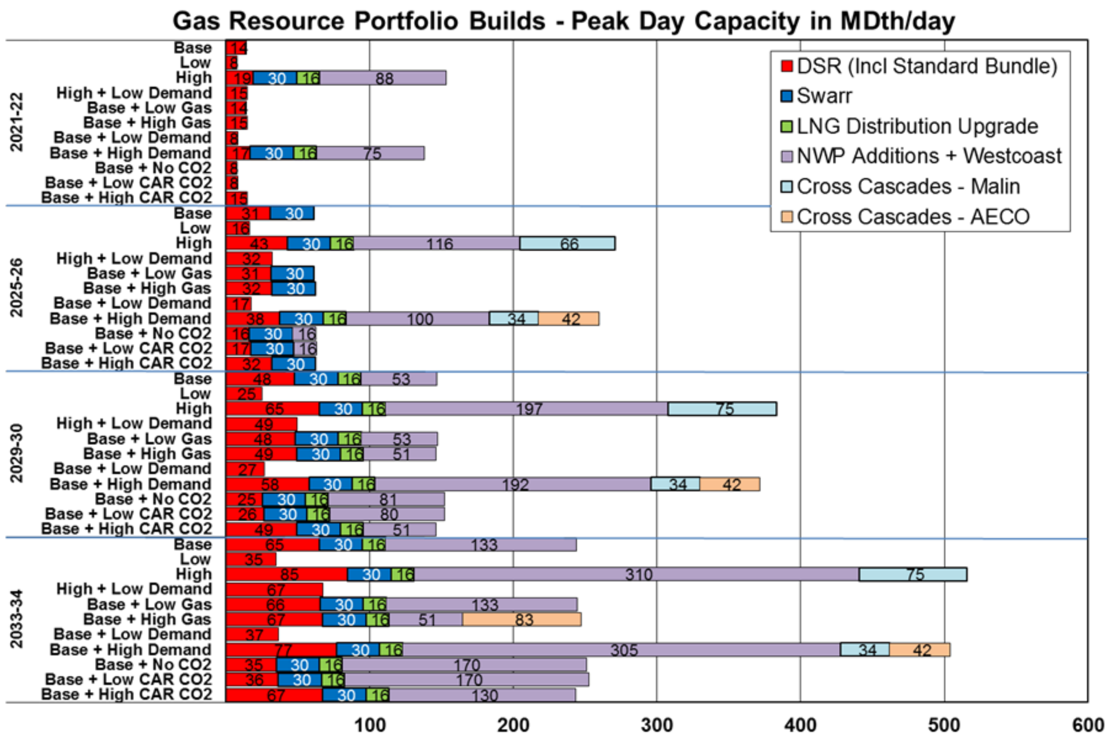
	2025/26	2029/30	2037/38
Conservation	27	49	84
Swarr Upgrade	30	30	30
LNG Distr. Upgrade	0	16	16
Additional NWP + Westcoast	0	61	140

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.

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 scenarios. Figure 2-10 illustrates the lowest reasonable cost portfolio of resources across those eleven potential future conditions.

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



Key Findings by Resource Type

Demand-side Resources

Cost effective DSR (conservation) does not vary dramatically across scenarios, especially in the early years, which is most important for program planning. Figure 2-11, below, shows the results of cost-effective DSR sorted by low, medium and high levels by 2022/23. The lowest levels of cost-effective DSR correspond to scenarios with low demand or low carbon costs. The highest levels of cost-effective DSR correspond to cases with high load growth. The mid-level cost-effective DSR includes scenarios with mid load growth and mid-to-high carbon costs.

Figure 2-11: DSR Results Sorted by Cost Effective Levels

	Low DSR 8 MDth/Day	Mid DSR 14-15 MDth/Day	High DSR 17-19 MDth/Day
Scenarios	Low	Base	High
	Base + Low Demand	High + Low Demand	Base + High Demand
	Base + No CO2	Base + Low Gas	
	Base + Low CAR CO2	Base + High Gas	
		Base + High CAR CO2	

Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in every scenario except for the three scenarios with low demand, which do not require any resources beyond DSR. The timing of the Swarr upgrade is driven by the load forecast. In scenarios with high load forecasts, Swarr is needed by 2021/22. In the mid-growth scenarios, Swarr is needed by 2025/26. Upgrades to Swarr are essentially within PSE's ability to control, so we have the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, as expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. We focused on this flexibility in the Timing Optimization Sensitivity, and found we could push the Swarr upgrade out one year, from 2022/23 to 2023/24. A decision on the timing of the Swarr upgrade is not needed now; the upgrade has a short lead-time, and we have the flexibility to adjust as the future unfolds.

LNG Distribution Upgrade

The cost effectiveness of upgrades to the distribution system to allow more gas to be withdrawn from PSE's Tacoma LNG storage facility are driven by the load forecast. In the three low-growth scenarios, this resource is not needed. In the high-growth scenarios, the LNG Distribution Upgrade is needed by 2021/22. The Base Scenario shows a need for it by 2029/30. Similar to Swarr, PSE has significant control over when the distribution system could be upgraded to increase withdrawal volumes from our Tacoma LNG peaking facility, so we have the flexibility to adjust the timing as the future unfolds.

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines North, to Station 2, is cost effective in every scenario, except those with low load growth. In the high load growth scenarios, 75-88 MDth/day is needed by 2021/22, growing to more than 300 MDth/day by the end of the planning horizon. In the mid-load growth scenarios, there are some slight timing differences. The Base + No CO_2 and Base + Low CAR CO_2 Scenarios show 16 MDth/Day of NWP + Westcoast Pipeline additions would be cost effective by 2025/26, but the other scenarios with mid-load growth do not. This is the effect of less conservation being cost effective in these two scenarios. Notice in Figure 2-10, above, those two scenarios have about 16 MDth less DSR than the other mid-growth scenarios – 16-17 MDth/day DSR in the former scenarios versus 31-32 MDth of DSR in the other mid-load growth scenarios.

Cross Cascades to Malin or AECO

These resources appear cost effective primarily in the high load growth scenarios. 83 MDth/day of Cross Cascades to AECO appears in the Base + High Gas Scenario by the end of the planning horizon as well. This is primarily being driven by price differentials between the different supply basins.

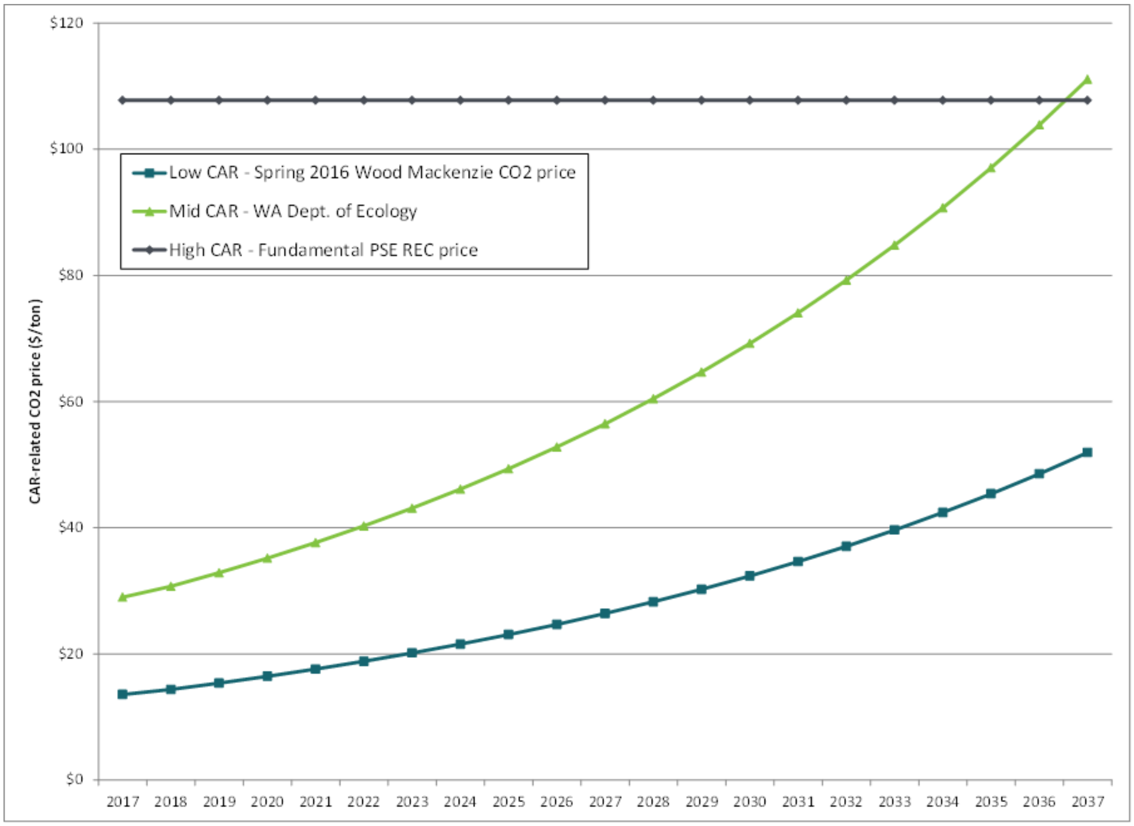
Resource Plan Forecast – Decisions

The resource plan forecast additions identified above are consistent with the optimal portfolio additions produced for the Base Scenario by the SENDOUT gas portfolio model analysis tool, including results of the Resource Timing Optimization Sensitivity. 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. The following summarizes key decisions for the resource plan.

Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Base Scenario – the same as several other scenarios, as shown in the table in Figure 2-10, above. Gas prices appear to have little impact on DSR within the mid-load growth forecast. The primary variable that affects the resource decision is the assumption for carbon prices. CAR is being challenged in court, so it may not be implemented, but even if it is, and carbon prices are in the range of the low carbon prices modeled, cost-effective DSR would be cut in half. Figure 2-12 illustrates the different carbon prices. At this time, we need to make a decision which significantly affects the result, with no confidence in our ability to forecast carbon prices. However, even if CAR is not implemented, PSE believes some kind of carbon regulation will affect our gas utility operations in the future. Low carbon prices have no effect on the cost effectiveness of conservation, but the base and high carbon cases have the same result; they include twice the amount of conservation. These results lead us to conclude that it would be more reasonable to incorporate DSR from the Base and High CO_2 scenarios. While in the future we may not see carbon prices in this range, conservation programs take years to accumulate savings. We believe this is a reasonable hedge against the risk of higher carbon prices.

Figure 2-12: Annual Range of CAR-related CO_2 Prices Used in the 2017 IRP



Supply-side Resources

The supply-side resources – Swarr, LNG Distribution Upgrade, and pipeline expansions – follow the Base Scenario resource additions, including results of the Timing Optimization Sensitivity, which moves Swarr out one year relative to the Base Scenario. All the resource plan forecasts based on mid-load growth have the same set of least-cost resource additions, once we account for the difference in DSR due to the No or Low CO_2 price scenarios. The only exception is in the Base + High Gas Scenario. In that scenario, some pipeline capacity on Cross Cascades up to AECO appears cost effective after 2030. This is driven by forecasted widening price differentials between AECO and Station 2, probably due to higher LNG exports from Northern British Columbia in that scenario. This is not an urgent issue to resolve, as PSE-controlled resources appear adequate to meet our customer's needs until 2029/30. It does highlight the importance of continuing to monitor the long-term outlook of natural gas prices at our different supply basins. We will file four more IRPs by the end of 2025, and we will be doing just that.

3

2017 PSE Integrated Resource Plan

Planning Environment

This chapter reviews the conditions that defined the planning context for the 2017 IRP.

Contents

1. GREENHOUSE GAS EMISSIONS

At present, the future of greenhouse gas (GHG) regulation at the federal, state and local levels is uncertain at best. However, PSE cannot ignore the possibility that *some* level of change to regulatory policies regarding carbon-emitting generating resources and/or the use of natural gas as a heating source is likely to occur during the 20-year planning horizon of this IRP. Summarized below are some of the current regulatory initiatives that have the potential to impact the operation of PSE's existing power supply portfolio, future resource acquisition decisions and the operation of PSE's natural gas distribution system.

Clean Air Rule

The Clean Air Rule (CAR) promulgated by the Washington State Department of Ecology (DOE) is effective beginning in 2017. This rule is intended to address GHG emissions from in-state non-mobile sources, petroleum product producers and importers, and natural gas distributors. While CAR would establish emission standards to "cap and reduce" GHG emissions, it would not be a full "cap and trade" program like California's existing program. New emission sources, like new baseload gas plants, are permitted. CAR would allow covered sources to create emission reduction units (ERUs) if a source's emissions levels are below the targets set by the state – or to purchase ERUs if the source operated above the targets. An emissions source may then bank its ERUs for future use or sell them. With CAR just beginning in 2017, the volume of ERUs is unknown at this point and likely very limited. So, instead of sources having the option to purchase large volumes of CO_2 credits to offset their physical GHG emissions (as in California's program), compliance with CAR will be achieved primarily through actual GHG reductions or through the purchase of carbon credits available from emissions programs outside of Washington state.

The CAR program has a significant impact on both PSE's existing power resource portfolio and any new PSE resource additions, because it will generally increase the costs of carbon emitting generating resources like natural gas-fired plants compared to carbon-free resources such as wind and solar. PSE's natural gas distribution customers will also be affected because PSE will need to purchase ERUs (if available) to offset a portion of its customers' natural gas usage. Quantifying the potential financial impacts of CAR on PSE and its customers is challenging, given that prices for ERUs will likely be established via a market-based negotiation process that could result in PSE's actual compliance costs being significantly higher or lower than forecast.

CAR is the subject of several lawsuits challenging the validity of the rule, but the rule is in effect nevertheless. Accordingly, PSE needs to be prepared to incorporate CAR into its long-term electric and natural gas resource planning processes. This situation necessitates that PSE maintain flexibility in evaluating the risks associated with the potential acquisition of any new power supply resources until the full impacts of CAR are known and quantified.

Clean Power Plan

The federal Clean Power Plan (CPP) applies carbon costs to all existing and new baseload generating facilities located in the U.S based upon a set of state-specific GHG reduction targets and associated compliance plans. Potential consequences for PSE include higher operating costs for its existing fleet of natural-gas and coal-fired generating plants as well as increasing the forecasted cost of adding new carbon-emitting resources. The CPP could be implemented as a cap and trade system in which trade may or may not be implemented across different states. Or, it could be implemented as a carbon intensity system that targets a tons per MWh metric in which some elements of interstate trading may or may not be implemented. Different applications of the CPP could lead to different results.

Twenty-seven states and other entities have filed lawsuits to block the Environmental Protection Agency's (EPA) implementation of CPP on the grounds that the EPA lacks the authority under the Clean Air Act to regulate GHG emissions. In 2016, the United States Supreme Court stayed the EPA's implementation of CPP pending judicial review (the case is currently pending in the D.C. Circuit Court). In addition, the current federal administration issued an Executive Order on March 28, 2017 in favor of energy independence that calls for review of specific regulations affecting the energy industry including the Clean Power Plan. On April 4, 2017, the EPA announced that it is reviewing CPP regulations, and if appropriate, will initiate proceedings to suspend, revise or rescind the CPP. While implementation in the short term is uncertain, it is still possible (and likely) that some form of the CPP could be implemented during the 20-year planning horizon of this IRP. This situation again requires that PSE maintain flexibility in the evaluation of, and potential acquisition of, new power supply resources while the future of the CPP is being debated.

Other State and Local Government Policies

In addition to the EPA's proposed CPP and Washington state's CAR, various entities within the state, including several local government bodies, have recently adopted or are currently discussing additional carbon-reduction initiatives. For example, Washington voters rejected a ballot initiative in 2016 to create a statewide carbon tax, but several state lawmakers continue to support this concept. In addition, stakeholders are currently reviewing carbon pricing policies, and have filed three such measures with the Office of the Secretary of State. Local jurisdictions have also discussed potentially restricting the development of new carbon-emitting resources, including coal and natural gas-fired combustion turbines. King County's Strategic Climate Action Plan and King County Cities Climate Collaboration (K4C) set renewable energy goals to use 100 percent carbon-neutral energy in county operations by 2025, to phase out coal-fired electricity sources by 2025 and to limit new natural gas based electricity power plants. The City Councils of Seattle and Olympia have passed resolutions calling on PSE to stop operating Colstrip by 2025. The City of Edmonds City Council recently approved amendments calling for city-owned buildings be powered completely by renewable energy by 2019 and for the city's community electricity to come from renewable sources by 2025, and a number of counties and cities have also passed similar resolutions. These are not binding regulatory requirements, but clearly demonstrate a significant number of the political leaders in our service territory are concerned about climate change and the role Colstrip plays in it.

Changing Customer Priorities

Beyond the political activities mentioned above, PSE has been partnering with customers seeking ways to meet their electricity needs with renewable resources. These include large commercial customers, small to mid-size businesses and residential customers. To serve these customers, PSE has developed a number of elective programs that are approved and monitored by the WUTC such as the Green Direct, Solar Choice and Green Power Programs, and we are committed developing further such products. These programs are important, because they provide customers with the ability to express their own preferences about the energy used to supply them, beyond the standard regulatory compact that requires PSE to minimize costs. Our first offering of Green Direct, marketed to larger commercial customers and government entities, was very successful. This program directly supported development of the Skookumchuck wind facility. PSE is working toward a second open season for the Green Direct Program and will continue to look for ways to partner with customers in meeting their energy needs.

2. REGIONAL RESOURCE ADEQUACY

Because PSE relies on more than 1,600 MW of wholesale market purchases to meet its current and forecasted energy and peak demand obligations,[1] we must monitor regional resource adequacy issues closely and be prepared to modify our purchase strategy accordingly should changing conditions warrant. To this end, PSE will continue working in conjunction with other regional planning entities such as the Northwest Power and Conservation Council (NPCC), Bonneville Power Association (BPA), and the Pacific Northwest Utilities Conference Committee (PNUCC) in order to improve existing analytical tools and to develop consensus assumptions for use in regional resource adequacy assessments.

For more than a decade, the Pacific Northwest region's large capacity surplus has kept wholesale power prices relatively low and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation. However, the long-term load/resource studies developed by the region's major energy organizations, NPCC, PNUCC and BPA,[2] while they differ in some details, generally point in the same direction: The current Pacific Northwest (PNW) energy and capacity surplus is expected to cross over to deficit at some point in the next decade unless new supply-side and/or demand-side resources are developed. This IRP analysis is aligned to the analytical results of the NPCC's 2016 Regional Resource Adequacy Assessment, but that assessment was updated in July of 2017.[3] The 2017 update forecasts the region will be short of the 5 percent LOLP target by 2022, requiring 400 MW of effective capacity to achieve the target under the NPCC base assumptions.

Fortunately, recent evidence suggests that the region is in the process of adding new resources (mainly in the form of additional investments in conservation) to fill this forecasted resource gap. In fact, NPCC staff highlighted that if the region follows the guidance from the Seventh Power Plan, it will be adding approximately 600 MW of conservation every year. In addition, regional utility load forecast growth rates are continuing to trend downwards, thereby also closing some of the projected gap. Also, the amount of power that can be reliably imported into the region during winter and summer peak load events may be higher than the figures currently being used in the NPCC's resource adequacy model. Finally, PSE's shift to a 5 percent LOLP metric in this IRP for its capacity planning standard (as opposed to the Value of Lost Load approach used in the 2015 IRP) has resulted in a higher level of reliability being assigned to wholesale market purchases. While there is still some level of risk to PSE in relying on up to 1,600 MW of wholesale market

1 / See Chapter 6, Electric Analysis, and Appendix G, Wholesale Market Risk, for more detail on wholesale market purchases and peak need.
2 / These studies are included in Appendix F, Regional Resource Adequacy Studies.
3 / https://www.nwcouncil.org/media/7491213/2017-5.pdf

purchases to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP.

The extensive analysis performed in the 2017 IRP indicates that PSE wholesale market purchases above the 1,600 MW level, when paired with additional firm transmission import rights that PSE may have during peak load events, is both a reliable and cost-effective way for PSE to meet its forecasted resource need when compared against other available new resource alternatives. These conditions allow PSE to maintain a considerable amount of flexibility regarding future resource acquisitions while also allowing it to effectively manage other uncertainties in the planning environment such as future GHG regulation, climate change, potential changes in customer behavior and the increasing effectiveness of emerging and maturing technologies.

These are all reasons for increased confidence, however, uncertainties remain. Should the region be unable to achieve forecasted conservation targets, should the specific timing of some of the region's coal-fired generating plants change, or should unexpected demand-side or supply-side shocks render the region short of resources, risk to PSE's customers would increase substantially. PSE has also expressed concern that the 5 percent LOLP metric, which measures the likelihood of deficit events, may not adequately describe the duration or magnitude of potential regional deficit events. The diversity of PSE's resource portfolio means that we would be able to mitigate some of these effects by using thermal resources to fill gaps during non-peak hours, but we would still be unable to meet peak need under such circumstances. For this reason, it may be advisable to develop a supply-side resource option that could be built in less than two years, in case wholesale market risk changes significantly.

3. CLIMATE CHANGE

Climate change is happening at a global level,[4] and these changes are affecting the Puget Sound region. Already, the region has experienced "long-term warming, a lengthening of the frost-free season, and more frequent nighttime heat waves,"[5] according to a study by the University of Washington.

Climate change could affect PSE's power system operations and the IRP planning process in a number of ways. Changes in temperature, the frequency and duration of extreme weather events, hydro conditions, customer energy use and the number of customers served, will affect how much power PSE needs for its customers' energy demand and how much power is needed at times of peak energy usage.

PSE needs detailed climate projections to forecast how climate change will affect our service territory to understand and plan for the range of probable futures so that we can adapt to the climate of the future. By detailed climate projections, we mean fundamental, scientific climate models, not just statistical analysis of recent trends.

At this time, there is not enough data to do a robust analysis of how our service territory, peak need, energy demand and conservation programs will change as a result of climate change. In the next section, we describe the data we believe is needed to do robust modelling of how climate change will affect our service territory and therefore our long-term capacity needs.

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4 / IPCC, 2014: Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp.

5 / Mauger, G.S., J.H. Casola, H.A. Morgan, R.L. Strauch, B. Jones, B. Curry, T.M. Busch Isaksen, L. Whitely Binder, M.B. Krosby, and A.K. Snover. 2015. State of Knowledge: Climate Change in Puget Sound. *Report prepared for the Puget Sound Partnership and the National Oceanic and Atmospheric Administration. Climate Impacts Group, University of Washington, Seattle. doi:10.7915/CIG93777D*

Impacts on Peak Need

Changes in weather are important for the IRP planning process because PSE forecasts are based on “normal” temperatures (last 30 years) and “normal” hydro conditions (1929 - 2008). If those normals are changing, we need to plan for that change and account for it in our modelling.

First and foremost, we need to understand how peak temperatures may change, because peak demand drives the need for additional capacity to meet the peak needs of both electric and natural gas service customers. Forecasting peak need is critically important for resource planning, and therefore understanding how extreme weather events may change is vitally important for integrated resource planning. We need data that will enable us to better understand these key questions:

- Are changes in extreme temperatures expected to change summer and winter peaks?
- Are sustained peaking events expected to increase or decrease?
- How will the severity and frequency of extreme events change?
- Will changes in the jet stream air currents mean arctic air dips into the region more frequently?[6]
- Will there be a change in humidity in the future?
- Could PSE’s service territory become a summer peaking utility, and if so, when?

A number of global climate models exist and could be downscaled to this region, but at this time it is not clear whether they can provide the needed information; simply scaling down large-scale averages is not sufficient.

Figure 3-1 shows the possible consequences to PSE of changes in extreme weather events. If extreme weather becomes more frequent and more severe than forecast, then PSE will likely need more flexible resources to respond to those events. If extreme weather events become less frequent and less severe, PSE will likely need fewer resources to respond. If there is no change in frequency or severity, we would expect no change in the planning process. However, if extreme weather events are more frequent but less severe, or more severe but less frequent, we need to understand these events better to forecast how they will affect our existing portfolio and new resource decisions. Currently, PSE is a winter peaking utility, however, the concept applies equally should climate change transition PSE to a summer peaking utility.

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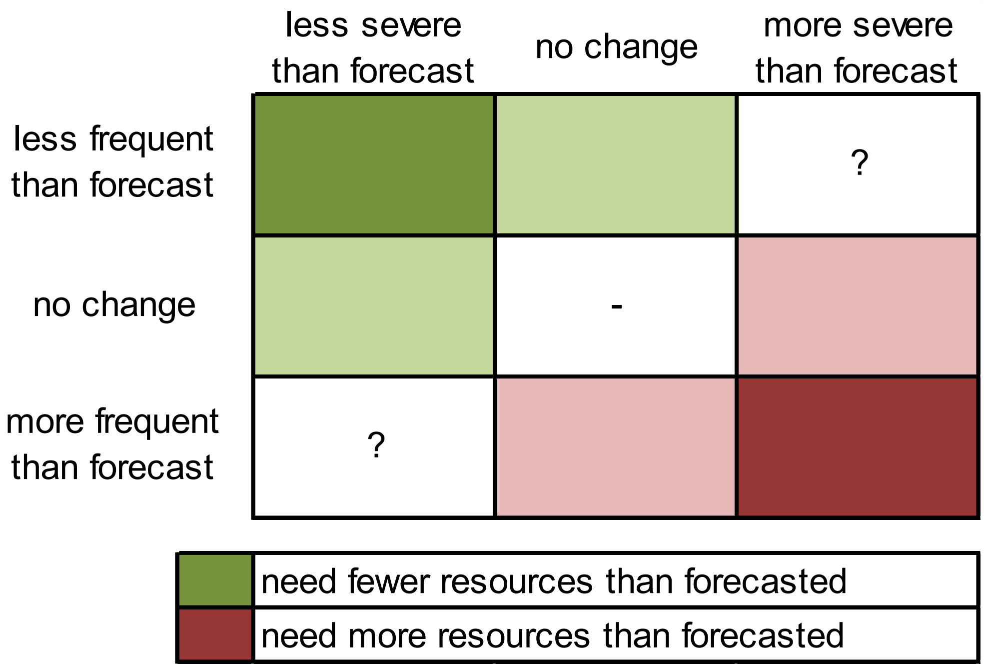
6 / Mooney, Chris “The Arctic is showing stunning winter warmth, and these scientists think they know why.” The Washington Pos,t 23 December 2016, https://www.google.com/search?q=The+Arctic+is+showing+stunning+winter+warmth&oq=The+Arctic+is+showing+stunning+winter+warmth&aqs=chrome..69i57j69i60.1774j0j7&sourceid=chrome&ie=UTF-8

Figure 3-1: Possible Effects of Climate Change on Extreme Weather



Impacts on Energy Need

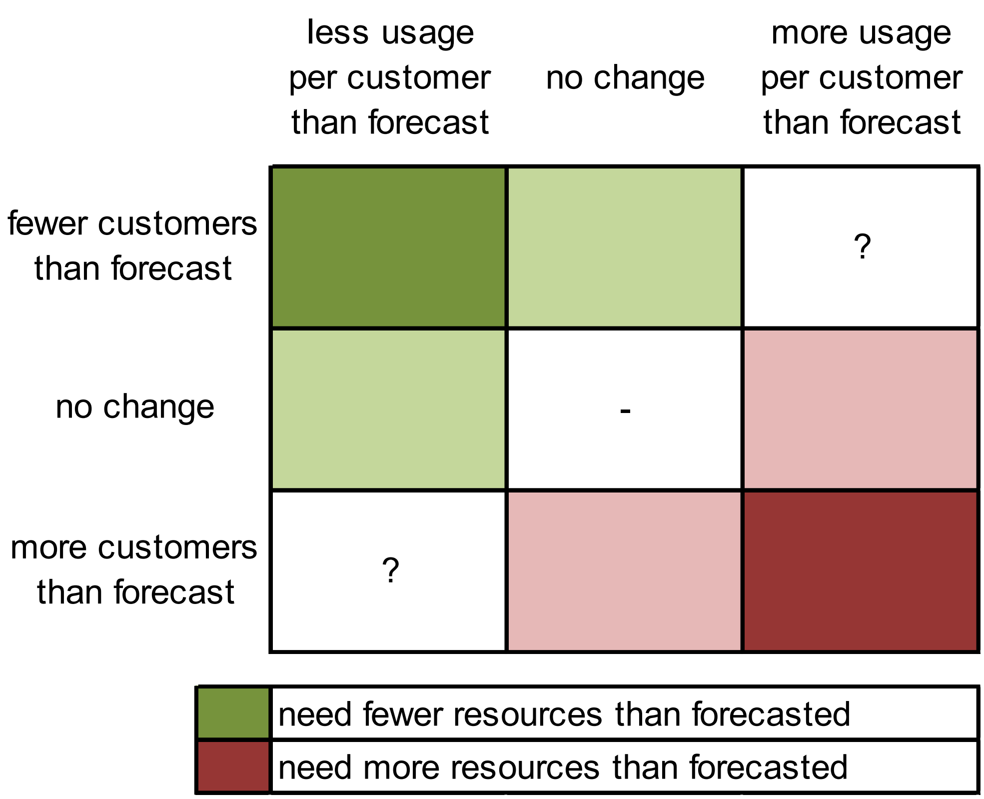
In addition to impacting peak need, climate change may also impact customer load growth in two ways: by changing customer energy usage patterns, and/or by changing the number of customers we can expect to serve.

First, we need data to better understand how climate change will affect individual energy usage. For example: How will customer energy usage change seasonally? Will there be an increase in air conditioner saturation over time, causing more energy usage at a given temperature? Will we see more solar PV installations, thus lowering customer demand in the summer? Will we see additional air conditioning load in the summer? PSE is working to develop an end-use load forecasting model that could be used to analyze energy usage at the customer level. Also, there are regional efforts to collect new end-use data that could be used in the model PSE is developing.

Second, we need data to better understand how climate change will affect the number of customers that PSE serves. How will regional, national or global changes affect migration patterns into or out of this region? Will other locations become less hospitable (due to sea level rise, desertification or increased temperatures) forcing people to move to more hospitable places, such as the Pacific Northwest as climate refugees? Will changes in the economy or the number of jobs cause people to move into or out of the service territory?

Figure 3-2 shows possible effects of climate change on energy demand. If PSE has more customers and higher use per customer than forecasted in a given season, then PSE may need more resources than forecasted. Similarly, if there are fewer customers and lower use per customer PSE will need fewer resources. However, the impact on resources is more uncertain if we see higher use per customer and lower customer counts or vice-versa.

Figure 3-2: Possible Effects of Climate Change on Loads



Impacts on the Hydroelectric System

Climate change may also bring changes to the regional hydroelectric system, changing the timing of runoff, the amount of runoff, or both. Changes to the hydroelectric system could affect PSE's hydroelectric generation as well as Mid-C wholesale prices and regional energy availability. Assuming that PSE and the Pacific Northwest region remains winter peaking, direct effects to PSE's peak capacity need should be minimal; that is, we could anticipate sufficient hydro power to shape generation to meet peaking needs in the winter. Changes in other seasons, however, could also impact operations. For example, changes in operating conditions on the Columbia River could reduce the amount of energy and capacity available in the summer. In addition, power markets could be impacted by larger minimum flows requiring longer periods of time to manage dissolved gases and water temperature for fish. This could lead to a loss of flexibility and ancillary services from the hydro sector.

To understand changes to the hydroelectric system we need to understand changes in snowpack and runoff and how these changes will affect hydro operations and the re-shaping of natural stream flows across the year. This could include changes in daily temperatures, precipitation changes, and seasonal weather trends and new environmental constraints on the hydro system. Also, it is possible that climate change could affect withdrawals of water from the region's reservoirs for non-power purposes such as irrigation or domestic water supply.

Understanding these changes will be useful for energy planning and planning for ancillary services, especially in the summer when natural stream flows into the hydroelectric system are at their lowest point. If we see an earlier peak and less water overall in the system, we would expect much less water and less energy from the hydro system in the summer.

There are regional efforts through BPA, the U.S. Army Corps of Engineers, and the Bureau of Reclamation to better understand the effects of climate change on the Columbia River hydroelectric system in terms of timing, overall annual runoff volumes, and the hydro system's ability to meet non-power constraints. PSE will be following these efforts closely to better understand how climate change will affect this regional resource.

Next Steps

This is not an exhaustive list of how climate change could affect PSE, its resources or the service territory. (For example, changes to cloud cover, winds, or wildfire could affect PV installation, wind generation or transmission lines.) We do not need a complete understanding of how climate change will unfold before starting to model some of its effects on the PSE system, however, we do need more information to perform a robust analysis, particularly fundamental, scientific climate change models that focus on the region. Developing or getting access to regional forecasts that will give us the information outlined above is a priority for PSE.

4. EMERGING RESOURCES/ENERGY STORAGE

Previous IRP's have included emerging resources and energy storage devices, however, PSE's ability to fully evaluate the potential benefits and associated costs of these resources was hampered by several factors. These include: 1) lack of historical industry operating data for grid-scale applications of these technologies, 2) a wide range of cost estimates for some devices, 3) uncertainties regarding potential future cost reductions and/or efficiency gains, 4) difficulties in valuing some of the attributes that emerging resource/energy storage devices can provide due to a lack of available pricing data, and 5) lack of an analytical tool that would allow PSE to fully incorporate the flexibility value of emerging resources/energy storage alternatives in its IRP planning process.

While some challenges remain (such as the lack of some historical pricing data), PSE has made great strides in this IRP in expanding its analysis of emerging resources/energy storage devices. In particular, PSE's acquisition of the PLEXOS model now allows PSE to model both conventional resources and energy storage devices down to a five-minute time interval as opposed to the hourly time interval previously used for PSE's evaluation of energy storage technologies. The addition of PLEXOS allows PSE to model the intra-hourly operational characteristics of both conventional resources and energy storage devices; this capability, in turn, expands PSE's ability to quantify the full value stream that energy storage devices can bring to PSE's resource portfolio.[7]

The 2017 PSE IRP modeled five different energy storage devices that incorporate three different technologies and operating characteristics: lithium-ion batteries, vanadium-flow batteries and pumped hydro storage.[8]

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7 / See Appendix H, Operational Flexibility, for a detailed summary of the PLEXOS model and PSE's operational flexibility analysis.
8 / Chapter 6, Electric Analysis, describes each of the energy storage alternatives analyzed.

While energy storage technologies other than batteries and pumped hydro storage exist – such as compressed air and flywheels – PSE did not model these technologies for several reasons. Compressed air storage facilities can be developed only at sites that have very specific geological conditions, which severely limits where these types of plants can be sited in the Pacific Northwest. And, while flywheel storage facilities can potentially be sited at a large number of different locations, this technology has yet to be proven in grid-scale operations. PSE therefore focused its evaluation of energy storage devices that: 1) are commercially available in grid-scale operations, and 2) can be reasonably sited in PSE's service territory and/or the Pacific Northwest region.

Battery storage technologies, in particular, are maturing, and manufacturing costs are being driven down by economies of scale, especially for lithium-ion batteries. In fact, the results of PSE's operational flexibility analysis for this IRP indicate that batteries are very close to being a cost-effective resource for PSE's portfolio.[9] PSE will continue to fine tune its flexibility analysis and the role that energy storage devices may have in future resource portfolios. In addition, it will be important for PSE to assemble additional data regarding the performance characteristics of energy storage technologies in actual utility grid-scale applications and to assess PSE's potential need for additional system flexibility as more intermittent resources are integrated into PSE's Balancing Authority Area.

9 / See Appendix H, Operational Flexibility for additional details.

5. GAS SUPPLY AND PIPELINE TRANSPORTATION

Natural gas supplies in the basins that serve PSE continue to exceed expectations due to the abundant supply of natural gas from shale formations and improving production techniques, despite the decreased likelihood of an LNG export terminal in the region. 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.

Though the regional gas transportation system is adequate to meet current demand, it is likely to experience increasing stress as gas customer growth continues – for example, if more of the region's electric generation requires natural gas for fuel, if liquefied natural gas (LNG) exports materialize, if large industrial uses such as methanol plants are developed, and as the transportation sector[10] continues to adopt natural gas as an attractive fuel option. However, increased demand for natural gas could be offset by new carbon policies, such as CAR. 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 is 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]

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*

6. 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 evaluating unsolicited or opportunistic offers, 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,

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

and qualitative factors. Results are re-evaluated as time passes and new information becomes available.

For example, 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.

4

2017 PSE Integrated Resource Plan

Key Analytical Assumptions

This chapter describes the forecasts, estimates and assumptions that PSE developed for this IRP analysis; the scenarios created to test how different sets of economic conditions affect portfolio costs and risks; and the sensitivities used to explore the impact of individual resources on the portfolio.

Contents

1. OVERVIEW

Economic Scenarios

Scenarios allow us to test how different combinations of three fundamental ***economic conditions*** impact the least-cost mix of resources. Given the set of static assumptions that define the scenario, deterministic optimization analysis is used to identify the least-cost portfolio of demand- and supply-side resources that will meet need under those conditions. For this IRP, PSE developed 14 scenarios for the electric portfolio and 11 scenarios for the gas portfolio.

Three Fully Integrated Economic Scenarios

Low, Base and High scenarios reflect different sets of assumptions for each of the three key economic inputs: customer demand, natural gas prices and CO_2 prices.

Eleven One-off Economic Scenarios

The one-off scenarios start with one of the fully integrated scenarios and change just one of the three fundamental economic inputs. In reality, when one economic condition changes, others usually do, too; however, one-off scenarios allow us to identify which of the three fundamentals has the most significant impact on the least-cost mix of resources.

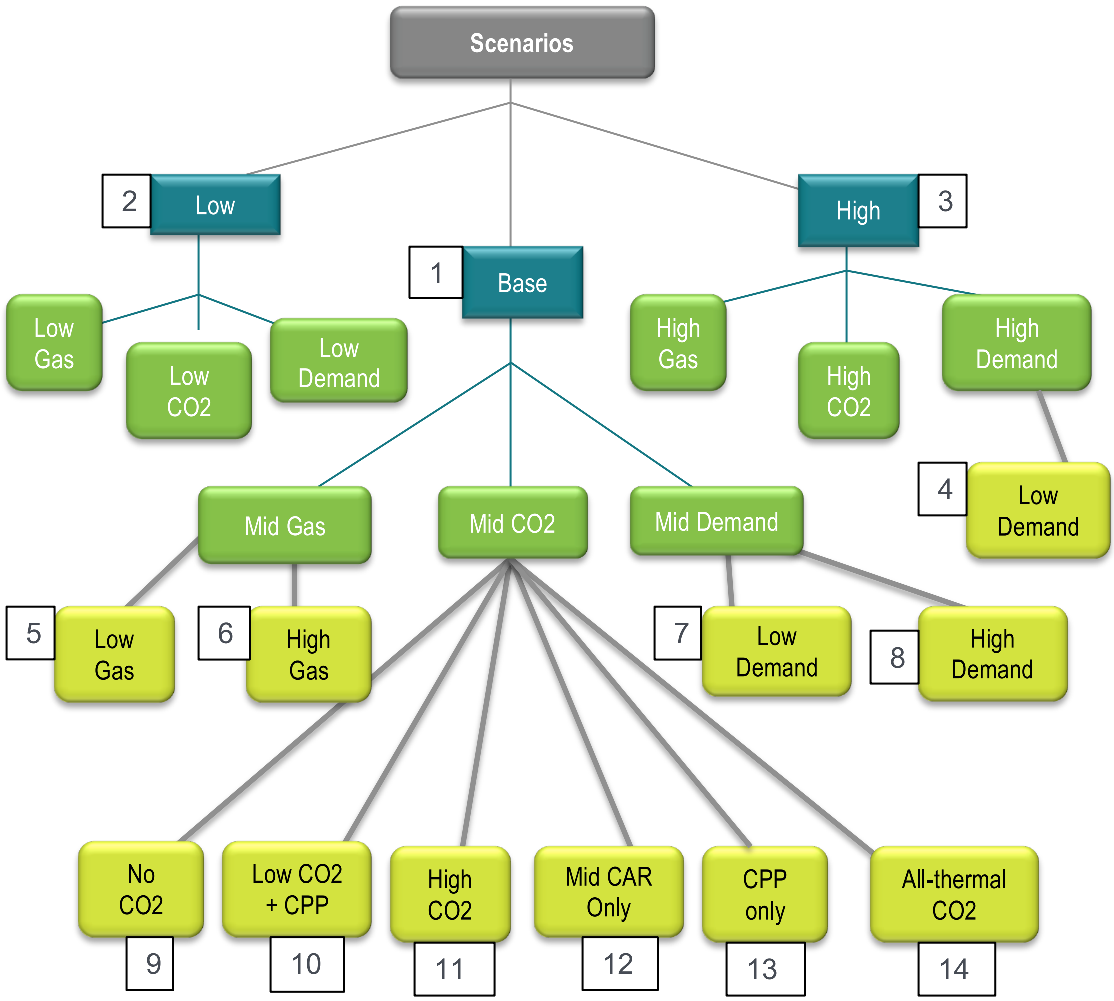
To complete the scenarios, we create wholesale power price forecasts for each one using production cost analysis described later in this chapter. Figure 4-1 illustrates the relationship between the fully integrated and one-off scenarios.

Portfolio Sensitivities

Portfolio sensitivities focus on the cost-effectiveness of a specific ***resource*** and the value it brings to the portfolio. First, PSE uses a portfolio optimization analysis to identify the least cost resource portfolio for each scenario. Then, starting with the least cost portfolio for the Base Scenario, the sensitivities change a single resource in the portfolio. Sensitivity analysis also allows us to explore how PSE might need to respond to unexpected changes in resource availability. The sensitivities are summarized in Figure 4-3.

Scenarios test how different combinations of three fundamental economic conditions impact the least cost mix of resources – demand, gas prices and CO_2 costs.

Figure 4-1: Diagram of 2017 IRP Scenarios



NOTES
CAR refers to Washington state Clean Air Rule regulations.
CPP refers to federal Clean Power Plan regulations.

The figure below presents the scenarios in tabular format.

Figure 4-2: 2017 IRP Scenarios

(A detailed description of scenarios begins on page 26.)

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

NOTES

1. Washington CAR (Clean Air Rule) regulations apply to both electric and gas utilities. These are applied to all scenarios.

2. Federal CPP (Clean Power Plan) regulations affect only baseload electric resources, so the gas portfolio models scenarios 1 through 11 only. CPP rules are modeled as if the entire WECC is part of an integrated carbon market, with carbon prices applied to all baseload generation, so that even if the CPP is ultimately not put into effect, the analysis still represents a form of carbon price regulation.

3. Carbon regulations are assumed to transition from CAR to CPP in 2022.

Portfolio sensitivities test the cost-effectiveness of a specific resource on the portfolio. Starting with the Base Case least cost portfolio, they change one resource.

Figure 4-3: 2017 IRP Portfolio Sensitivities

(A detailed description of portfolio sensitivity reasoning begins on page 38.)

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

	Sensitivities	Alternatives Analyzed
	ELECTRIC ANALYSIS	
J	**Alternate Residential Conservation Discount Rate** How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation?	*Baseline: Assume the base discount rate.* Apply a societal discount rate to residential conservation savings to examine whether changing the discount rate for conservation impacts cost effectiveness of conservation.
	WIND RESOURCES	
K	**RPS-eligible Montana Wind** [1] What is the cost difference between a portfolio with "regular" Montana wind and RPS-eligible Montana wind?	*Baseline – Montana wind included only if chosen economically by the analysis.* 1. Add RPS-eligible Montana wind in 2023 instead of solar 2. Montana wind tipping point analysis to determine how close it is to being cost effective compared to other resources.
L	**Offshore Wind Tipping Point Analysis** How much would costs of offshore wind need to decline before it appears to be a cost-effective resource?	*Baseline – Base Scenario portfolio* Offshore wind tipping point analysis to determine how much costs would have to drop to be cost effective compared to other resources.
M	**Hopkins Ridge Repowering** [2] Would repowering Hopkins Ridge for the tax incentives and bonus RECs be cost effective?	*Baseline – Hopkins Ridge repowering is not included in the portfolio.* Include Hopkins Ridge repowering in the portfolio to replace the current facility.

	Sensitivities	Alternatives Analyzed
	NATURAL GAS ANALYSIS	
A	**Demand-side Resources (DSR)** How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements.* No DSR. All future needs met with supply-side resources.
B	**Resource Addition Timing Optimization** How does the timing of PSE-controlled resource additions affect resource builds and portfolio costs?	*Baseline – PSE-controlled additions offered every 2 years.* PSE-controlled resource additions offered every year.
C	**Alternate Residential Conservation Discount Rate** Would using a societal discount rate on conservation savings from residential energy efficiency impact cost effective levels of conservation?	*Baseline – Assume the base discount rate.* Apply a societal discount rate to residential conservation savings.
D	**Additional Gas Conservation** What happens if DSR is added beyond what is cost-effective per RCW 19.285?	*Baseline – All cost-effective DSR per RCW 19.285 requirements.* Add 2 additional demand-side bundles.

NOTES
1. Montana wind is not currently an RPS-eligible resource; however, PSE has asked BPA under what conditions it could be qualified as an RPS-eligible resource.
2. Repowering refers to refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. These sensitivities capture the impact of tax credit incentives and increased operating efficiency on cost.

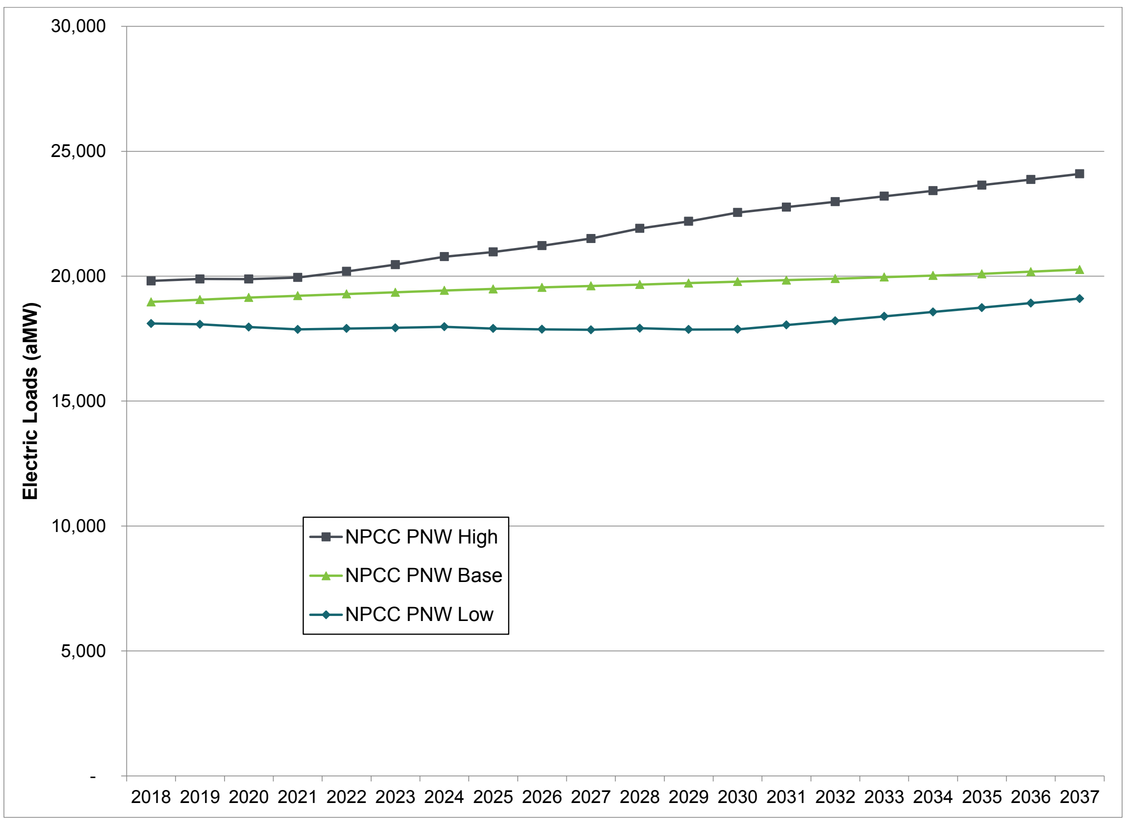
2. KEY INPUTS

Demand Forecasts

Regional Demand

Regional demand significantly affects power prices, so it must be taken into consideration. This IRP uses the regional demand developed in the Seventh Power Plan by the Northwest Power and Conservation Council (NPCC or "the Council").[1] Regional demand is used only in the WECC-wide[2] portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Figure 4-4: NPCC Regional Demand Forecast for Pacific Northwest (PNW) – Average, not Peak



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.*
2 / *WECC, the Western Electricity Coordinating Council, is the regional forum for promoting regional electric service reliability in the Western United States.*

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 E, 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 **2017 IRP BASE DEMAND FORECAST** is based on 2016 macroeconomic conditions such as population growth and employment. *The 2017 IRP Base Scenario uses this forecast.*

The **2017 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 2017 IRP Low Scenario.

The **2017 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 2017 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 without including the effects of conservation. 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. The gas sales peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport.

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

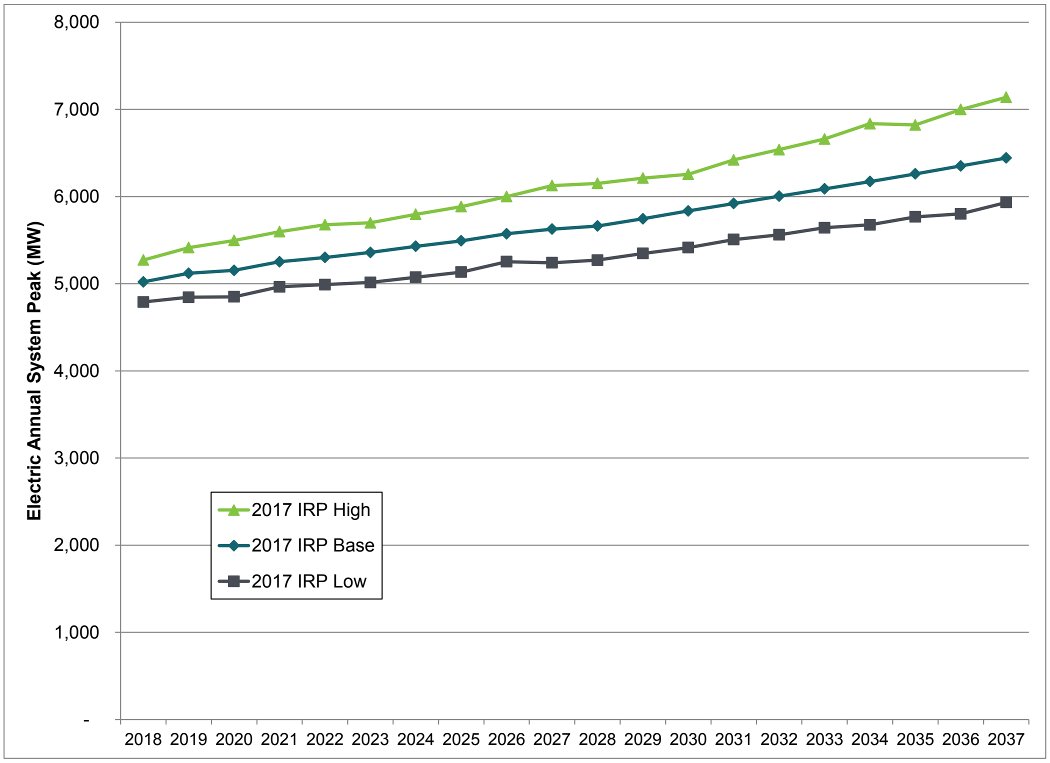


Figure 4-6: PSE Annual Electric Energy Demand Forecast (Low, Base, High)

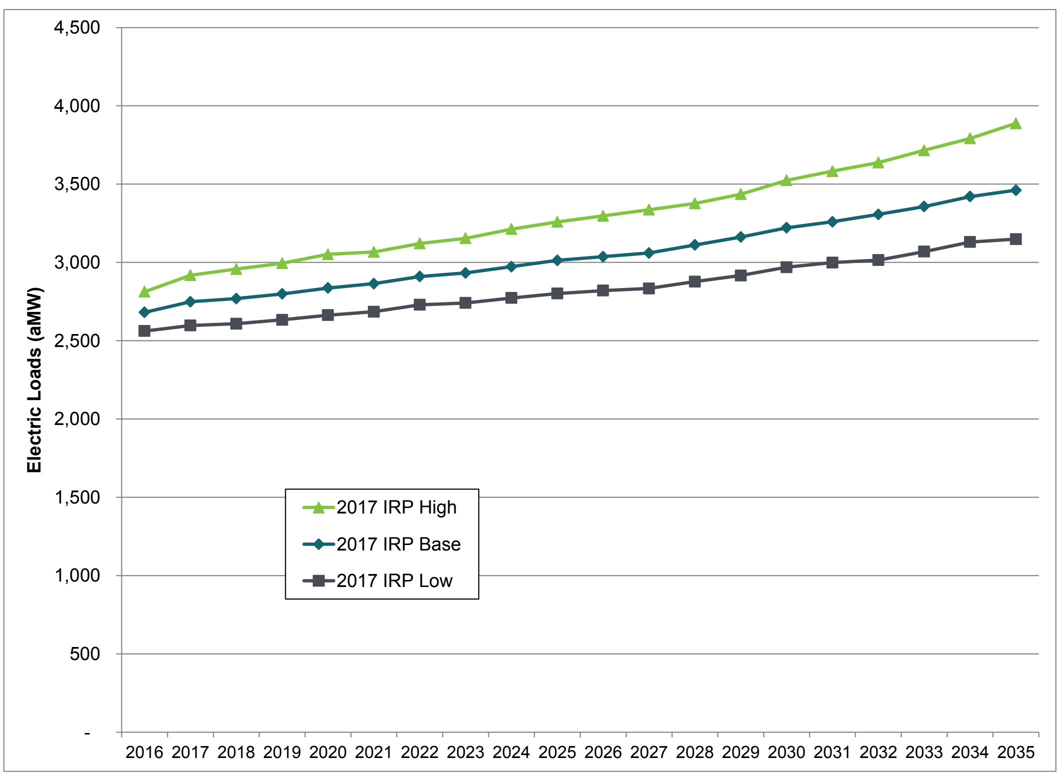


Figure 4-7: PSE Peak Day Gas Sales Demand Forecast (Low, Base, High)

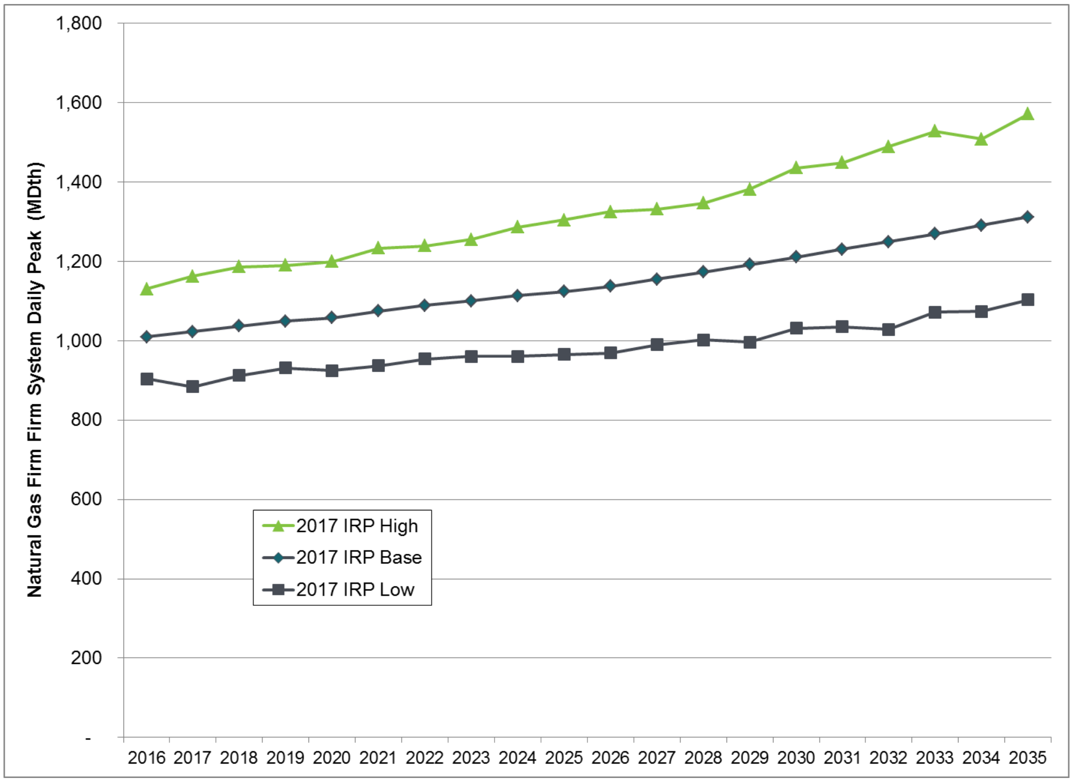
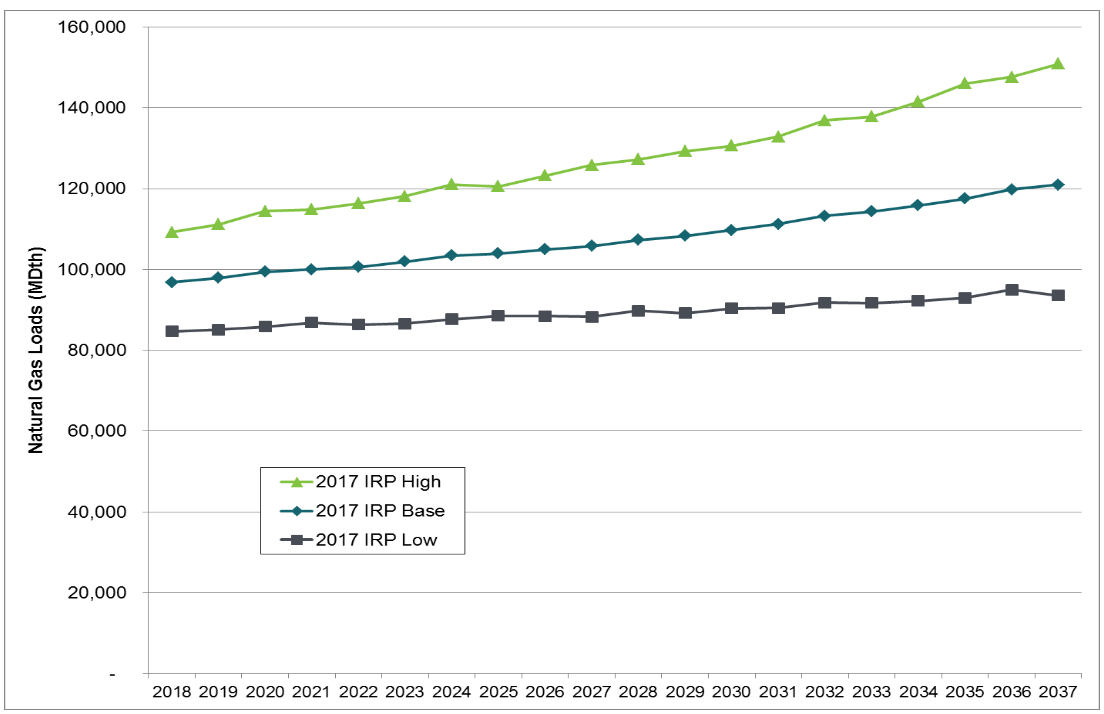


Figure 4-8: PSE Annual Gas Sales Demand Forecast (Low, Base, High)



Gas Prices

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

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

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

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

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 2018-2037, nominal $)

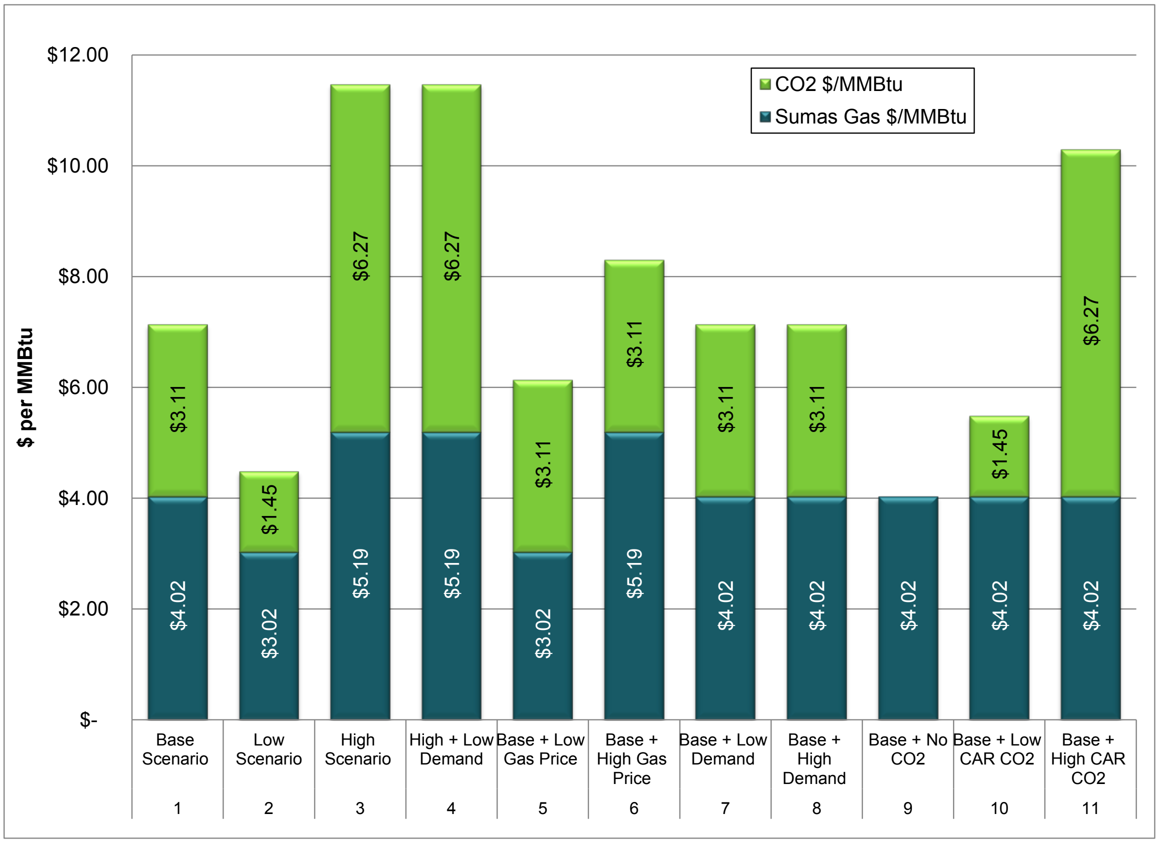
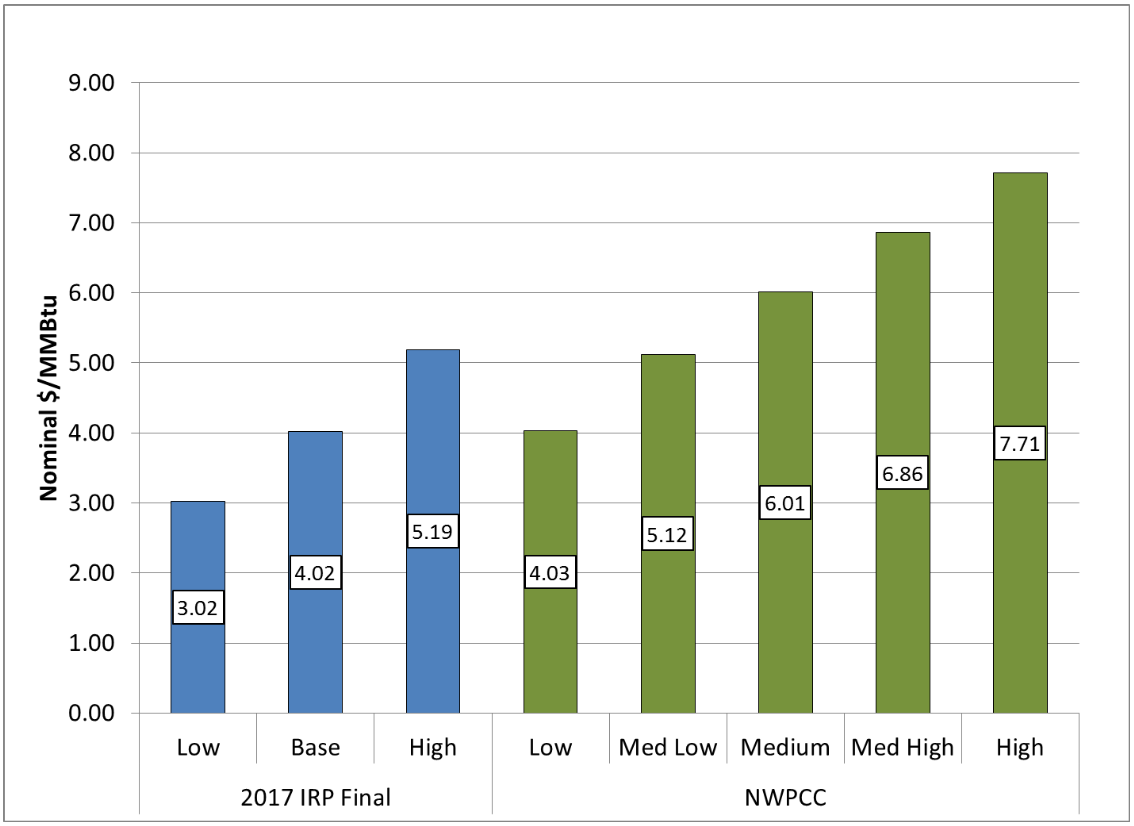


Figure 4-10 below, compares the levelized gas prices PSE used in this IRP with those used by the NPCC in its Seventh Power Plan.[3] This illustrates that the range of PSE's gas prices are consistent with the range of gas prices being used by the Council. It also shows PSE's Base Scenario gas price is slightly lower than the Council's medium gas price forecast.

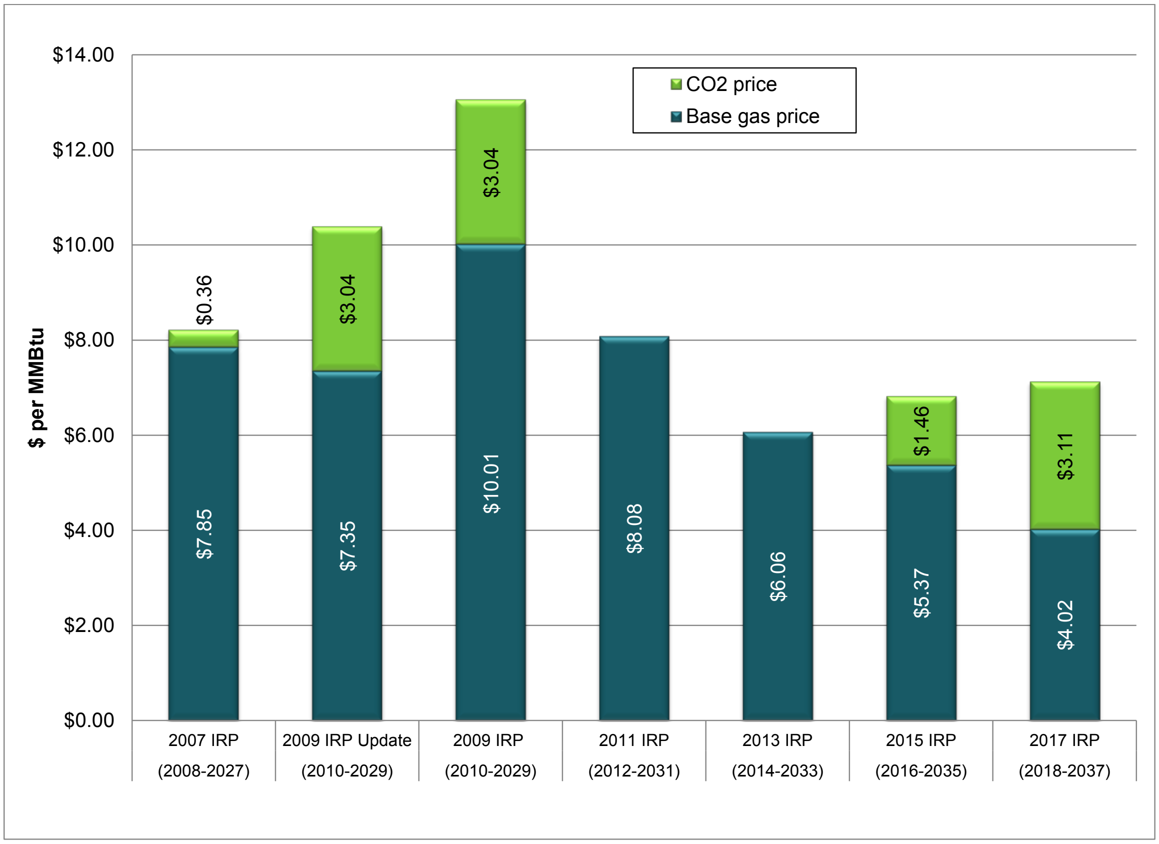
Figure 4-10: PSE 2017 IRP Gas Prices Compared to NPCC Seventh Power Plan Gas Prices (adjusted to nominal values)



3 / *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.*

Figure 4-11 below compares the levelized gas prices used in past PSE IRP analyses. The 2017 IRP gas price of $7.60 per MMBtu includes an estimated CO_2 price for the Washington Clean Air Rule (CAR).

Figure 4-11: PSE 2007 IRP – 2017 IRP Levelized Gas Prices



CO_2 Prices

The carbon prices in this IRP reflect the range of potential impacts from several key pieces of carbon regulation. The two most important are Washington state's Clean Air Rule (CAR) and the federal Environmental Protection Agency Clean Power Plan (CPP) rules. CAR regulations apply to both electric and gas utilities, and CPP regulations apply only to baseload electric resources. Even if CAR and CPP are ultimately not implemented, some form of carbon regulation is likely to be enacted during the 20-year period covered in this IRP, so it is important that the analysis reflect this possibility.

The Base Scenario in this IRP assumes the current rules – the Clean Air Rule and Clean Power Plan – will be implemented because it is impossible to model a generic carbon regulation scheme. Carbon taxes, carbon caps, or carbon cap and trade schemes could produce very different resource plans. Likewise, applying carbon regulation in one state versus the entire WECC would also produce very different results.

CAR. Washington state's CAR regulations took effect in January 2017. These regulations require state electric and gas utilities that exceed state CO_2 emissions to buy CO_2 allowances to compensate. Low, mid and high CAR prices have been developed as inputs to the analysis, because these allowances will come from a variety of sources whose costs can vary substantially. On the electric side, CAR only applies to in-state electric generating sources. CAR allows development of a carbon trading market, but it is not really a "cap and trade" system, because there is no cap. Under CAR, PSE (or any market participant) can build new natural gas plants that will essentially receive carbon allowances that diminish over time.

CPP. Federal CPP regulations are scheduled to take effect in 2022. These rules apply carbon costs to existing and new baseload electric generating facilities throughout the country. In this analysis, they are reflected as a carbon cost of $19 per ton in 2022, rising to $51 per ton in 2037. This cost is applied to all affected generating units in WECC states. CPP rules do not apply to gas utilities.

BASE CASE ASSUMPTIONS. PSE's Base Case assumes that federal CPP rules will supersede state CAR regulations in 2022. While it is possible that neither the CAR or CPP will actually be enforced, it is likely that some form of carbon regulation will be enacted during the 20-year study period. This IRP also examines a scenario in which no carbon regulation is ever implemented (the Base + No CO_2 Scenario), in the event that policy makers are unable to implement any binding regulations.

A table showing the annual CO_2 prices modeled can be found in Appendix N, Electric Analysis. All prices shown below are in short tons.

Mid CO_2 prices

The 2017 IRP Base Scenario uses this forecast.

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

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

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

Low CO_2 prices

LOW CAR CO_2 PRICE TO 2022: $14 PER TON IN 2018 TO $51 PER TON IN 2037

NO CPP

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

High CO_2 Prices

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

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

CAR estimate is based on PSE's fundamental REC price from the 2015 IRP. (The 2015 REC price was used because an input was needed before the 2017 IRP analysis output was available.) It reflects the difference between the levelized cost of power and the levelized cost of wind in the 2015 IRP. CPP estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32 and is applied WECC-wide as a CO_2 price to all existing and new baseload generating units affected under the CPP.

In addition, PSE modeled the following CO_2 prices in one-off scenarios.

Why model 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 does not fit this regulatory model. 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 world 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 explains why internalizing these externalities in typical IRP analyses is not a substitute for federal-level carbon regulation policies.

No CO_2 prices

Low CO_2 + CPP

LOW CAR CO_2 PRICE TO 2022: $14 PER TON IN 2018 TO $51 PER TON IN 2037

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

Mid CAR only (No CPP)

MID CAR TO 2037: $30 PER TON IN 2018 TO $111 PER TON IN 2037

CPP only (No CAR)

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

All-thermal CO_2

$19 PER TON IN 2022 TO $51 PER TON IN 2037, APPLIED TO ALL CO_2 EMITTING RESOURCES IN THE REGION

This estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32 and is applied WECC-wide to all CO_2 emitting resources, peaking plants and baseload generators. (CPP and CAR apply only to baseload generators).

Figure 4-12: Annual Range of CAR-related CO_2 Prices Used in the 2017 IRP

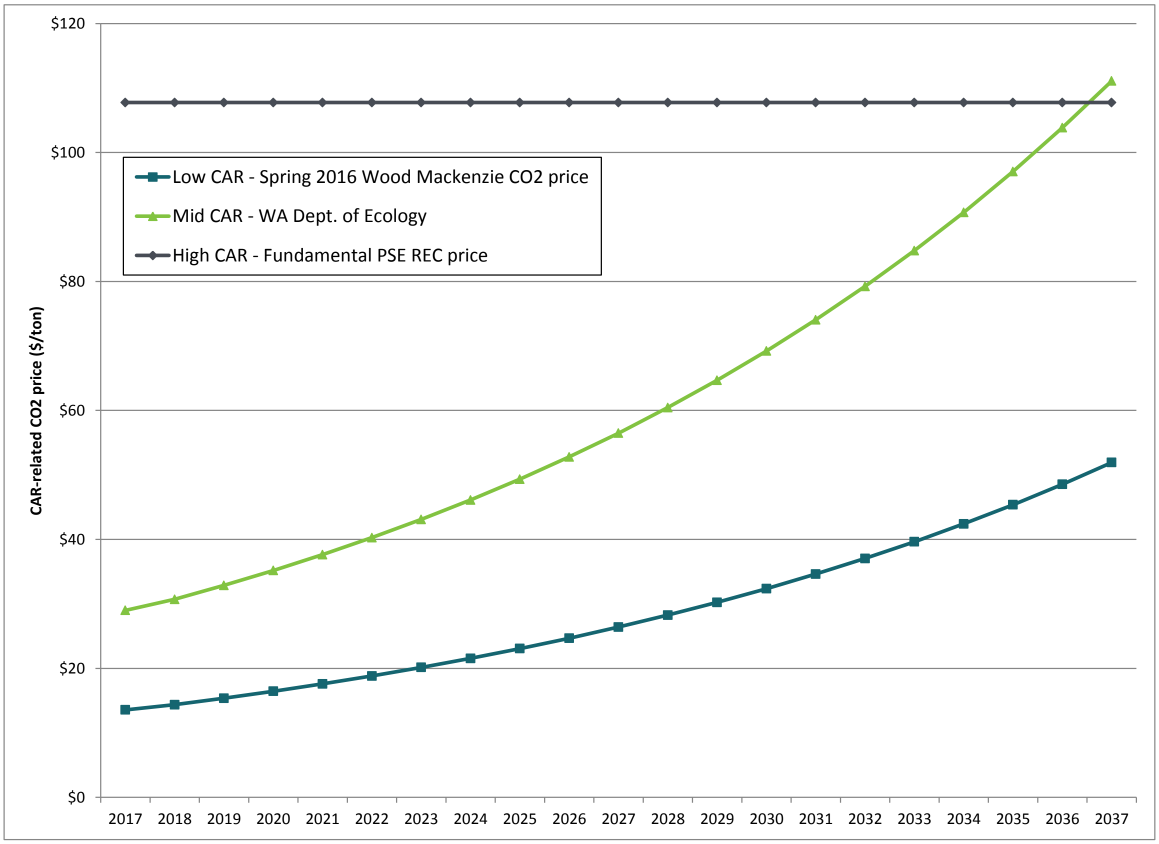
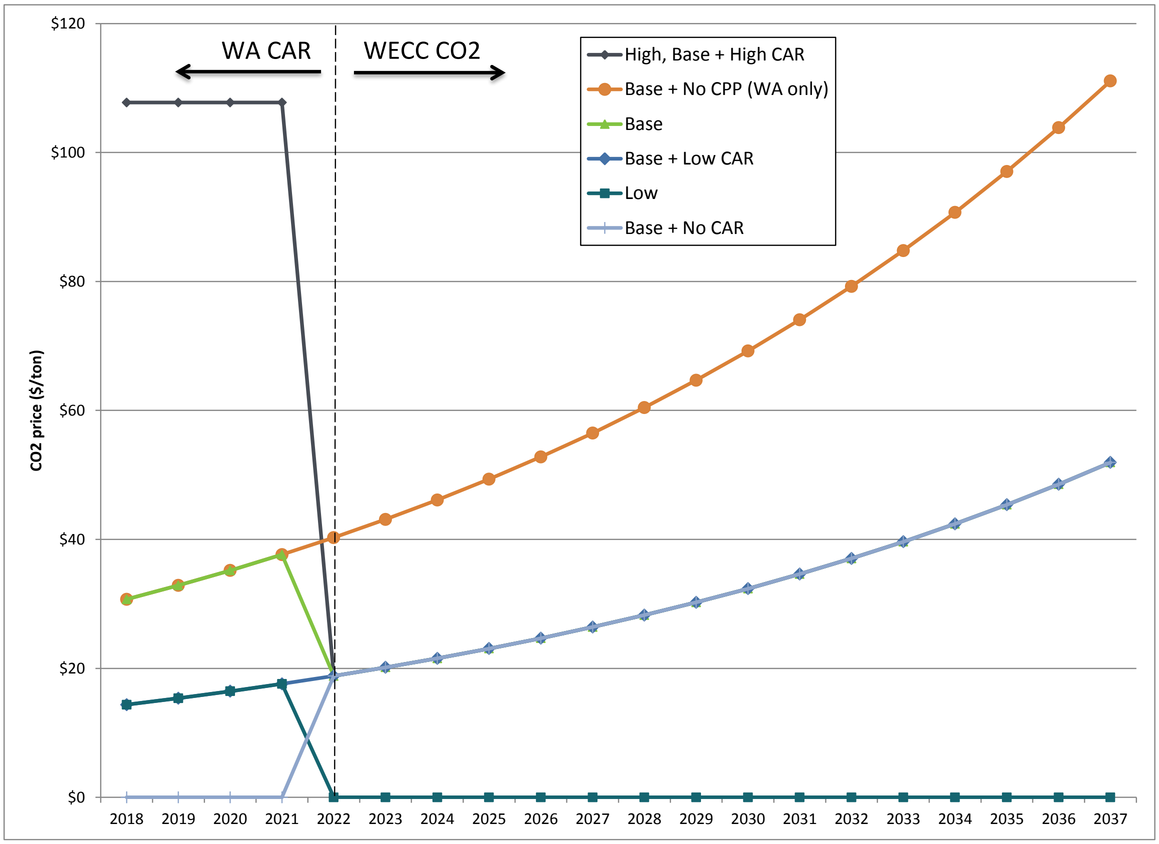


Figure 4-13: Annual CO_2 Prices for the Electric Price Modeling

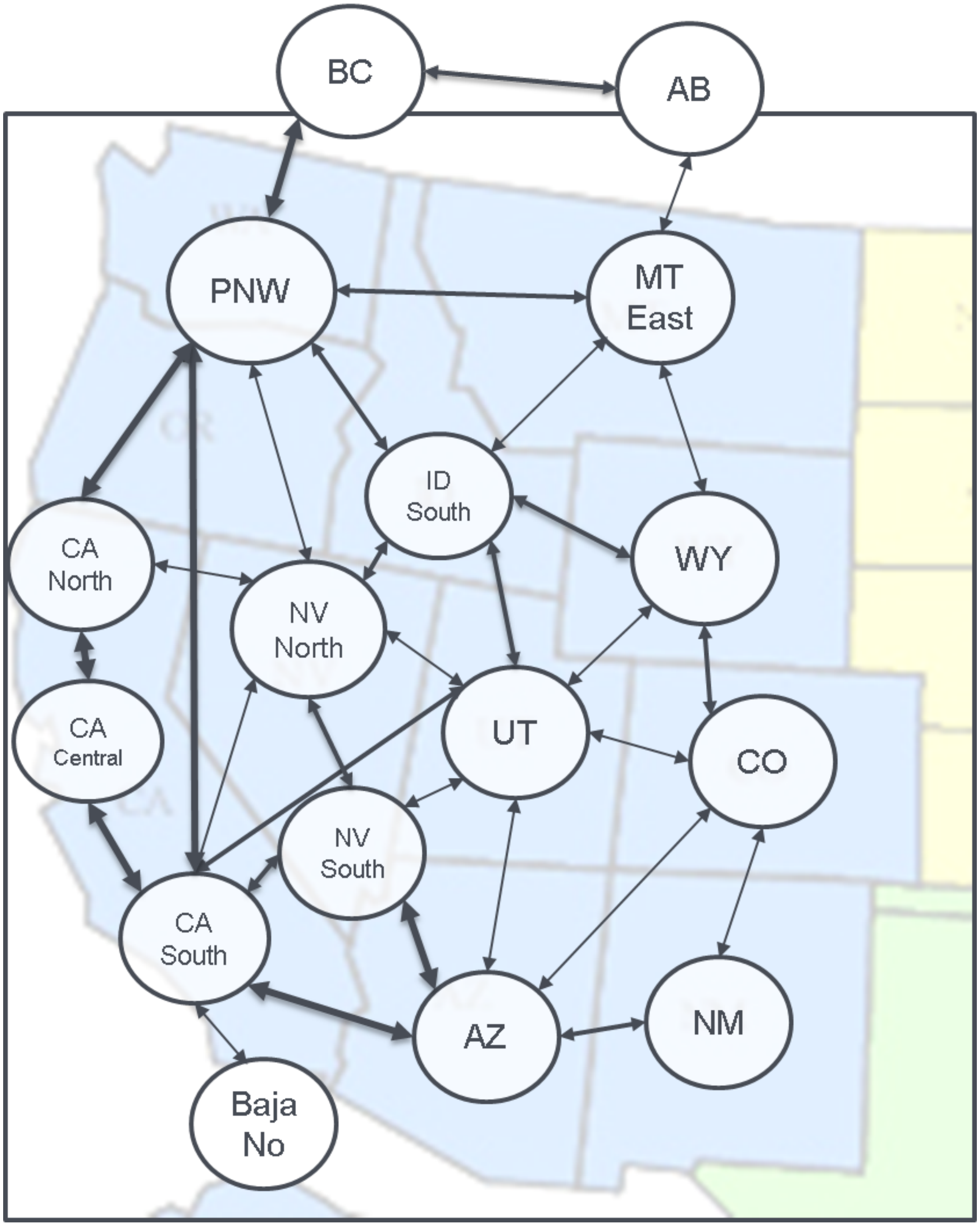


Developing Wholesale Power Prices

A wholesale power price forecast is developed for each of the 14 scenarios modeled. In this context, "wholesale power price" does not mean the rate charged to customers, it means the price to PSE of purchasing or selling 1 megawatt hour (MWh) 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. Wholesale market prices are also very important with respect to establishing the value of energy supply resources or conservation; e.g., if wholesale power prices are $45 per MWh, the value of 1 MWh of energy saved by a conservation measure or produced by a generator is $45.

AURORAxmp is an hourly chronological price forecasting model based on market fundamentals. The model reflects the dispatch and operating costs of about 3,700 individual generators, representing approximately 250 GW of installed generation capacity that are interconnected throughout the Western Electric Coordinating Council region (WECC). AURORA also reflects transmission constraints between sub-regions. Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the 14 scenarios (AURORA is discussed in more detail in Appendix N, Electric Analysis). The first run identifies needed capacity expansion to meet regional loads. AURORA considers loads and peak demand plus a planning margin, and then identifies the most economic resource(s) to add to make sure that the entire system maintains adequate resources. 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 16 zones shown in Figure 4-14 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.

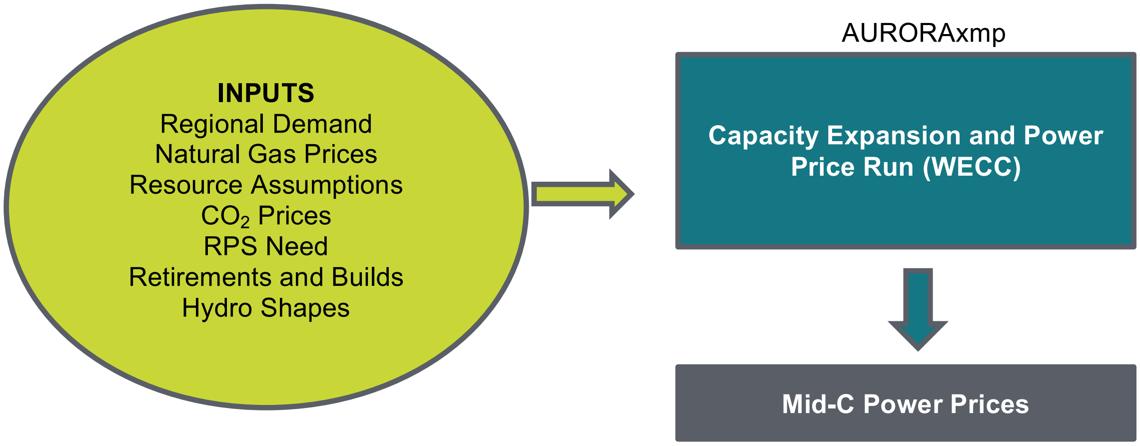
Figure 4-14: AURORA *System Diagram*



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

Figure 4-15 illustrates PSE's process for creating wholesale market power prices.

Figure 4-15: PSE IRP Modeling Process for AURORA Wholesale Power Prices



The database of inputs for AURORA starts with inputs and assumptions from the EPIS 2016 v3 database. PSE then includes updates such as regional demand, natural gas prices, resource assumptions, CO_2 prices, RPS need, and resource retirements and builds. Details of the inputs and assumptions for the AURORA database are included in Appendix N, Electric Analysis.

Figure 4-16 shows the 14 power prices produced by the 14 scenario conditions.

Figure 4-16: Power Price Inputs by Scenario,
Annual Average Flat Mid-C Power Price (nominal $/MWh)

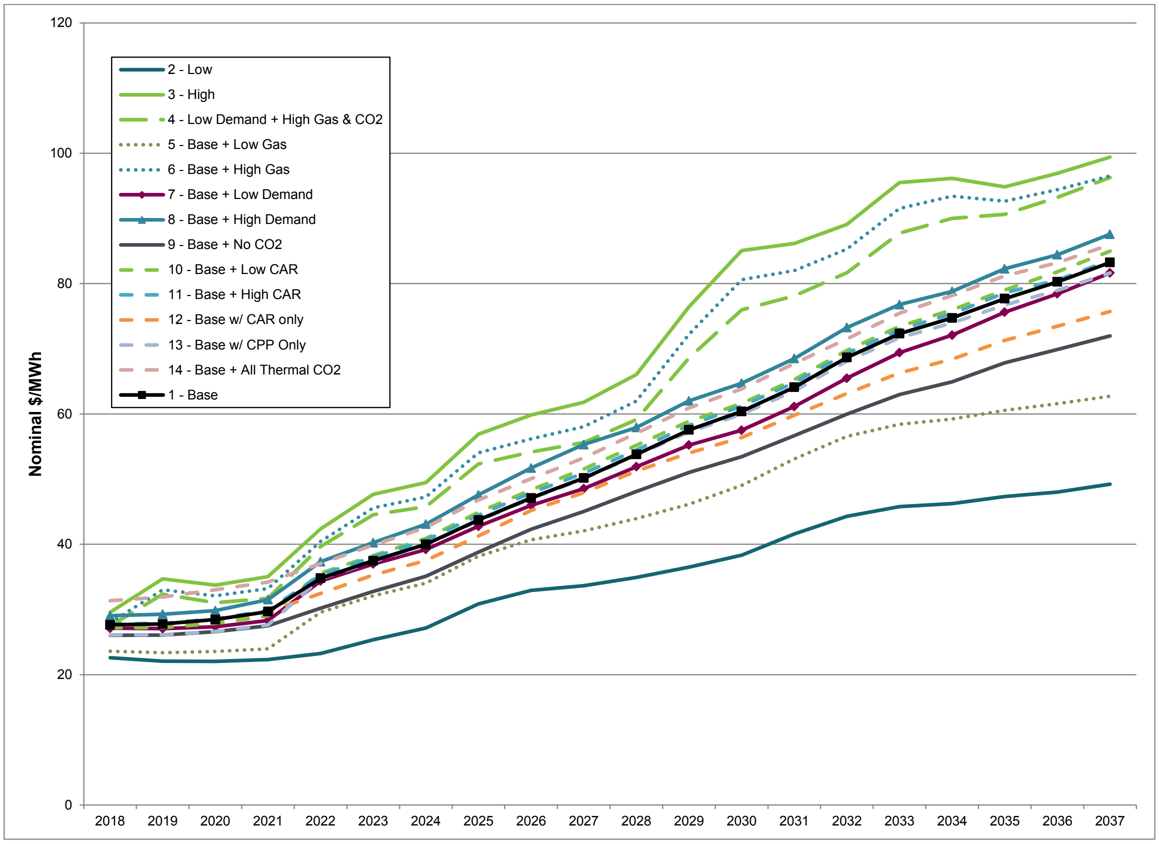
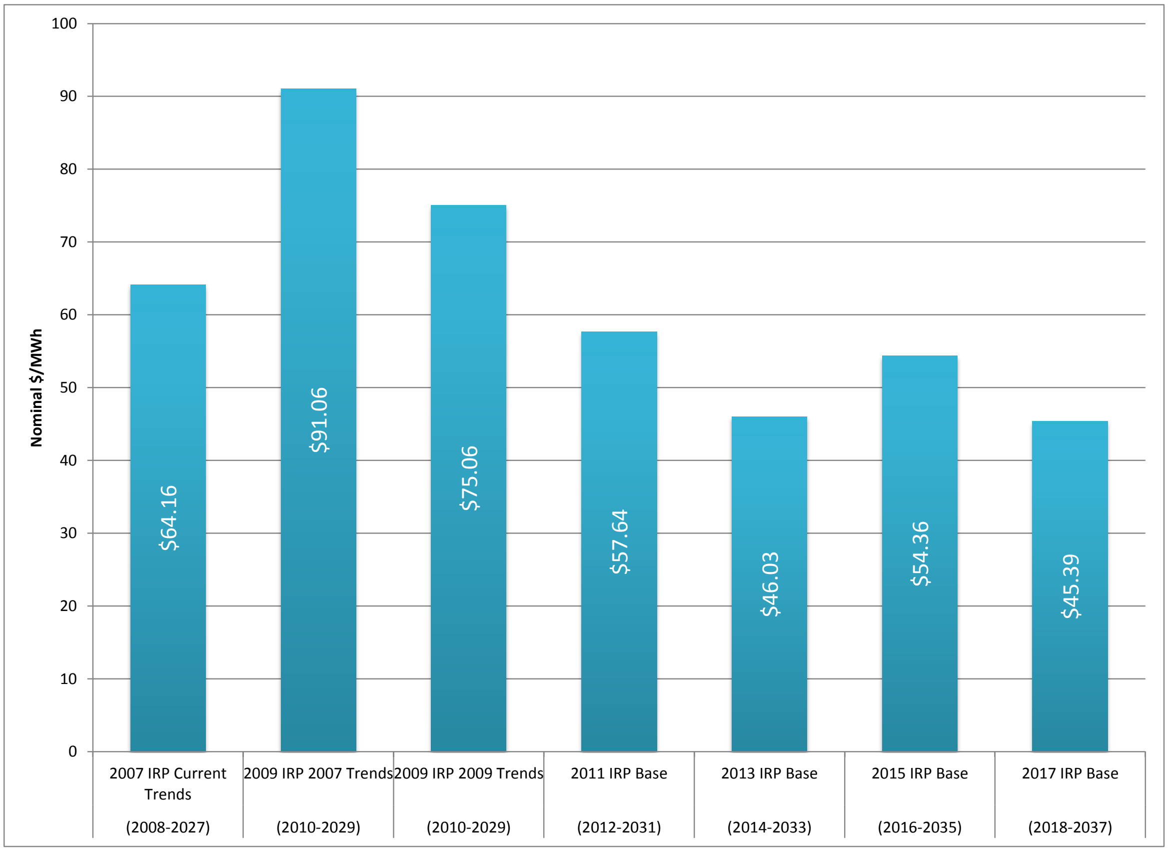


Figure 4-17 below compares the 2017 Base Scenario power prices to past IRP power prices. The downward revisions in forecast power prices correspond to the downward revisions in natural gas prices, as shown in Figure 4-11.

Figure 4-17: Levelized Power Price Compared to Past IRPs ($/MWh)



3. SCENARIOS AND SENSITIVITIES

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

Fully Integrated Scenarios

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

1. Base Scenario

- The Base Scenario applies the NPCC Seventh Power Plan regional demand forecast to the WECC region and the 2017 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.
- The Washington Clean Air Rule (CAR) is modeled on affected power plants in Washington state using mid CAR CO_2 prices from 2018-2021 for the electric portfolio and from 2018-2037 for the gas portfolio: $30 per ton in 2018 to $111 per ton in 2037. In 2022, when the EPA Clean Power Plan takes effect, electric utilities will move to the CPP price: $19 per ton in 2022 to $51 per ton in 2037. From 2022 – 2037, the CPP price is applied to all WECC states.

2. 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 Seventh Power Plan low demand forecast is applied for the WECC region, and the 2017 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.
- Low CAR CO_2 prices are modeled from 2018-2021 for the electric portfolio and from 2018-2037 on the gas portfolio: $14 per ton in 2018 to $51 per ton in 2037. No CO_2 price is applied to the WECC for compliance with the CPP.

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

3. High Scenario

- This scenario models more robust long-term economic growth, which produces higher customer demand. The NPCC Seventh Power Plan high demand is applied for the WECC, and the 2017 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 2018-2037).
- High CAR CO_2 prices are modeled from 2018-2021 for the electric portfolio and from 2018-2037 for the gas portfolio: $108 per ton in 2018 to $108 per ton in 2037. In 2022 the CPP price is then applied to all WECC states: $19 per ton in 2022 to $51 per ton in 2037.

One-off Scenarios

Eleven one-off scenarios start with one of the fully integrated scenarios and change just one of the three key economic conditions.

4. High Scenario + Low Demand

This stakeholder requested scenario models low customer demand in the context of High Scenario assumptions (high gas prices and high CO_2 prices); it applies the 2017 IRP Low Demand Forecast.

5. Base + Low Gas Price

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

6. 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 2018-2037 to Base Scenario assumptions.

7. Base + Low Demand

This scenario models low customer demand in the context of Base Scenario assumptions; it applies the 2017 IRP Low Demand Forecast.

8. Base + High Demand

This scenario models high customer demand in the context of Base Scenario assumptions; it applies the 2017 IRP High Demand Forecast.

9. Base + No CO_2

This scenario removes a CO_2 price for CAR and CPP from Base Scenario assumptions.

10. Base + Low CO_2 w/ CPP

This scenario models a low CO_2 price for CAR compliance from 2017-2021 and the CPP carbon price from 2022-2037 in the context of the Base Scenario assumptions.

11. Base + High CO_2

This scenario models a high CO_2 price for CAR compliance from 2018-2021 and the CCP carbon price from 2022-2037 in the context of the Base Scenario assumptions.

12. Base + Mid CAR only (electric only)

This scenario removes CPP compliance for the electric portfolio in the context of the Base Scenario assumptions. CAR is modeled from 2018-2037.

13. Base + CPP only (electric only)

This scenario removes CAR compliance for the electric portfolio in the context of the Base Scenario assumptions. CPP is modeled from 2022-2037.

14. Base + All-thermal CO_2 (electric only)

Both CAR and CPP target baseload resources only, which excludes peaking plants. This scenario models a CO_2 price applied to all thermal resources in the WECC in the context of Base Scenario assumptions for demand and gas prices.

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.)

Demand-side resources included 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 to accomplish a given amount of work. These include three categories: retrofit programs that have shorter lives, such as efficient light bulbs; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that will drive down energy consumption through government regulation. (Codes and standards have no direct cost to utilities).

DEMAND RESPONSE. Demand response resources are like energy efficiency in that they reduce customer load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely, and are discussed in more detail in Appendix J, Conservation Potential Assessment.

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators (like rooftop solar panels) located close to the source of the customer's load. This also includes combined heat and power systems.

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.

Renewable supply-side resources included the following.

WIND. Wind was modeled in southeast Washington and central Montana. Washington wind is assumed to have a capacity factor of 30.4 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 46 percent.

OFFSHORE WIND. Although wind off the coast of Washington is not a commercially available resource at this time, it was modeled in the portfolio analysis in response to stakeholder interest. Wind off the coast would have to be located in deep water more than 22 miles offshore since established shipping lanes run the entire length of the Washington coast. The only technology suitable for such depths would be floating platforms, and so far there has been only a one-turbine demonstration project. Offshore wind is described in more detail in Appendix D.

ENERGY STORAGE: BATTERIES. Two battery storage technology systems are analyzed: lithium-ion and flow technology. These systems are modular, and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour, 4-hour and 6-hour battery systems for both technologies.

ENERGY STORAGE: PUMPED HYDRO. 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. Pumped hydro resources can provide sub-hourly flexibility values similar to batteries, and they are utility scale. Because they are located remote from substations, they cannot contribute the transmission and distribution benefits that smaller battery systems can provide at the local system level. Pumped hydro can provide some benefits to the bulk transmission system, however, such as frequency response and black start capability.

SOLAR. Utility-scale solar PV was modeled in central Washington in PSE's service territory and southern Idaho. This solar is assumed to use a tracking system and have a capacity factor of 27 percent in Washington and 30 percent in Idaho.

Other supply-side resources included the following.

BASELOAD GAS PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTS). F-type, 1x1 engines with wet cooling towers are assumed to generate 359 MW plus 54 MW of duct firing, and to be located in PSE's service territory. These resources are designed and intended to operate at base load, defined as running more than 60 percent of the hours in a year.

FRAME PEAKERS. (SIMPLE-CYCLE COMBUSTION TURBINES). F-type, wet-cooled turbines are assumed to generate 239 MW and to be located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

AERO PEAKERS. (AERODERIVATIVE COMBUSTION TURBINES). The 2-turbine design with wet cooling is assumed to generate a total of 227 MW and to be located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

Baseload and peakers

"Baseload" generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year.

"Peaker" is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload resources.

RECIP PEAKERS. (RECIPROCATING ENGINES). This 12-engine design with wet cooling (18.7 MW each for gas-only and 17.1 MW for duel fuel), is assumed to generate a total of 222 MW (202 MW duel fuel) and to be located in PSE's service territory.

REDIRECTED TRANSMISSION. "Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.

Resource Cost Assumptions

The estimated cost of generic thermal resources are based on a September 2016 study by Black and Veatch done on behalf of PSE (see Appendix N for the full report). Renewable resource costs are based on information from a different consultant, DNV-GL.

Resource costs are generally expected to fall in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). A sensitivity that examines more aggressive cost reductions for utility-scale solar was also examined. Appendix D, Electric Resources and Alternatives, contains a more detailed description of resource cost assumptions, including transmission and gas transport assumptions.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes plant, siting, sales tax, system upgrades 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 4-18 summarizes generic resource assumptions.
- Figure 4-19 displays the monthly capacity factor for Washington wind, Montana wind, Washington solar.
- Figure 4-20 summarizes annual capital cost by vintage year for supply-side resources and energy storage.

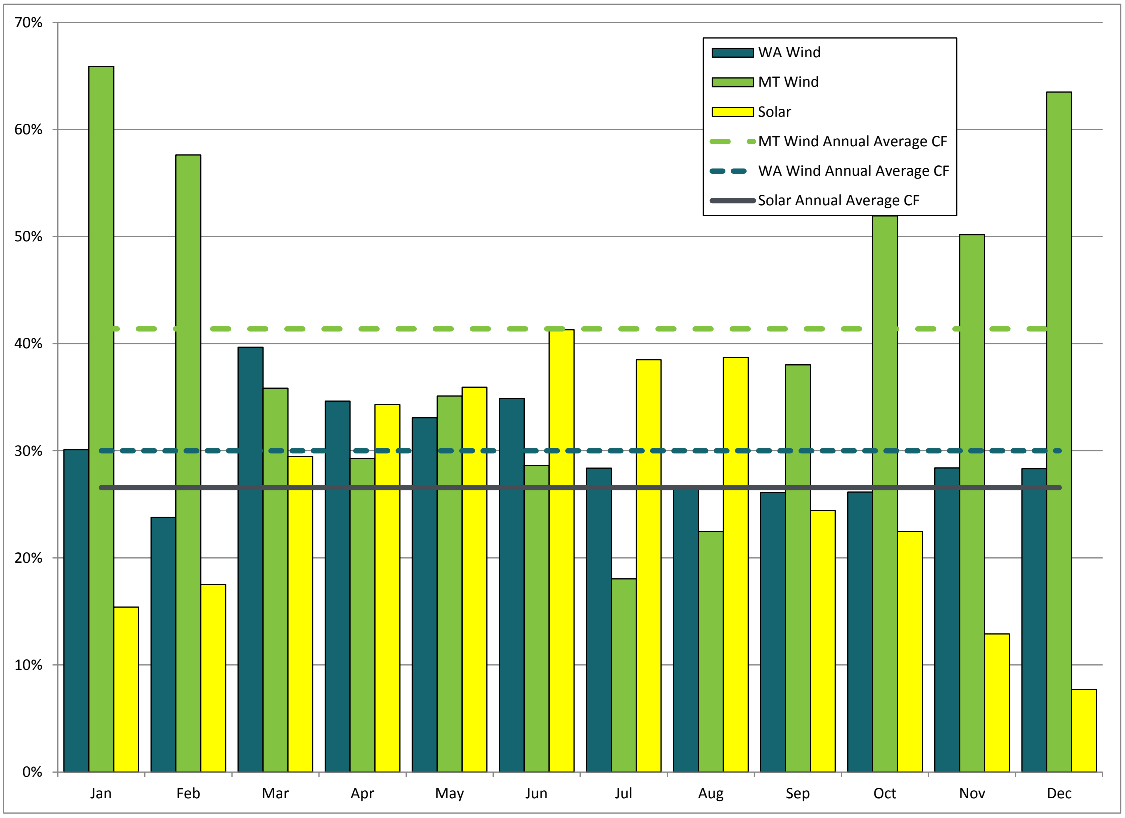
Figure 4-18: New Resource Cost Assumptions

IRP Modeling Assumptions (2016 $)	Name -plate (MW)	First year available	Capacity Factor[1] (%)	Overnight Capital Cost ($/kw)	Fixed O&M [2] ($/kw-yr)	Variable O&M ($/MWh)	Baseload Heatrate[3] (Btu/kWh)
F-Class CCCT 1x1 with DF	413	2022	N/A	$1,267	$8.10	$2.50	6,650
Frame Peaker Duel-Fueled 1x0 with Oil Back-up	239	2021	N/A	$639	$11.23	$0.95	9.823
Frame Peaker NG only 1x0	239	2021	N/A	$571	$6.40	$0.95	9.823
Aero Peaker Duel-Fueled 2x0 with Oil Back-up	227	2021	N/A	$1,070	$10.92	$10.20	8,986
Aero Peaker NG only 2x0	227	2021	N/A	$1,004	$6.50	$10.20	8,986
Recip Peaker Duel-Fueled 12x0 with Oil Back-up	202	2021	N/A	$1,477	$10.70	$7.80	8,527
Recip Peaker NG only 12x0	222	2021	N/A	$1,277	$6.50	$7.80	8,425
Wind Plant - Washington	100	2020	30%	$1,939	$27.12	$3.15	N/A
Wind Plant - Montana	300	2022	46%	$2,065	$33.79	$3.50	N/A
Offshore Wind	100	2022	35%	$7,150	$77.30	$3.15	N/A
Central Station Solar Tracking PV	25	2020	26%	$2,041	$10.00	$0.00	N/A
Biomass	15	2021	85%	$3,950	$113.70	$5.66	N/A
2-hour Lithium Ion Battery	25	2019	N/A	$1,514	$23.68	$0.00	N/A
4-hour Lithium Ion Battery	25	2019	N/A	$2,439	$36.49	$0.00	N/A
4-hour Flow Battery	25	2019	N/A	$2,324	$26.82	$0.00	N/A
6-hour Flow Battery	25	2019	N/A	$3,042	$23.40	$0.00	N/A
Pumped Storage Hydro	25	2030	N/A	$2,400	$15.00 ,	$0.00	N/A

NOTES
1. Expected factor for wind, solar and Biomass; for thermal resources, the capacity factor is dependent on dispatch cost for the scenario.
2. Fixed O&M with oil backup includes the cost for 48 hours worth of oil.
3. Heat rate for CCCT is for the primary unit, the heat rate for the secondary duct firing is expected to be 8,500 Btu/kWh.

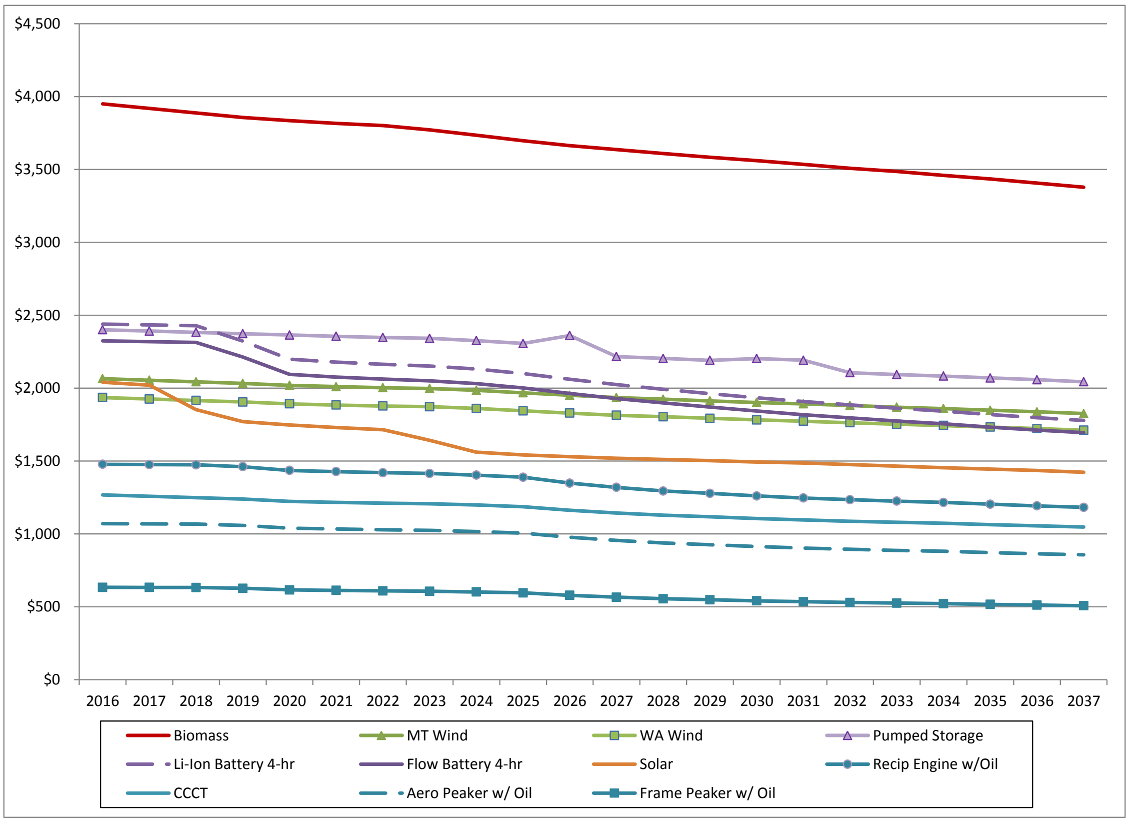
Figure 4-19 displays the monthly capacity factor for Washington wind, Montana wind, and Washington solar.

Figure 4-19: 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 2015 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 4-20 shows the annual capital cost of a resource by year built in 2016 real dollars.

Figure 4-20: Annual Capital Costs by Vintage Year (real 2016 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

Two federal subsidies are currently available to reduce renewable resource costs in the U.S; the production tax credit (PTC) and the investment tax credit (ITC). Both wind and solar projects are given the option to choose between the PTC or ITC.

PTC. The PTC is phased down over time for wind facilities (starting at 100 percent) and expires for other technologies commencing construction after December 31, 2016.

- For wind facilities commencing construction in 2017, the PTC amount is reduced by 20 percent
- For wind facilities commencing construction in 2018, the PTC amount is reduced by 40 percent
- For wind facilities commencing construction in 2019, the PTC amount is reduced by 60 percent

To meet the safe harbor rules, a project must meet the “physical work” test or show than 5 percent or more of the total cost of the project was paid during that year. For example, if a project began construction or paid 5 percent or more in costs in the year 2019, it will receive the 40 percent PTC even if the facility doesn’t go online until 2022. The PTC is received over 10 years and is the rate prescribed annually by the IRPs in dollars per MWh.

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

- wind: 30 percent in 2016, 24 percent in 2017, 18 percent in 2018 and 12 percent in 2019;
- solar: 30 percent 2016-2019, 26 percent in 2020, and 22 percent in 2021, , and 10 percent in years after 2021.
- Batteries if matched with a solar project can receive ITC if 75 percent of the energy comes from the project.

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

BONUS DEPRECIATION. This is an additional amount of tax deductible depreciation that is awarded above and beyond what would normally be available in the first year of a project. Bonus depreciation is available for all technology types, not just renewable resources, and is based on the when the plant is placed in service. This incentive is designed to promote investment sooner rather than later. The bonus depreciation is also phased down over time; 50 percent in 2016, 50 percent in 2017, 40 percent in 2018 and 30 percent in 2019.

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 2012, 9 percent in 2016, 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 renewable resources are accounted for, the difference is taken from the total RPS need and the existing resources and the net RPS need is then added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet the RPS need. Technologies modeled included wind and solar.

California Carbon Prices

The California Global Warming Solutions Act of 2006 (AB32) mandates a carbon price be applied to all power generated in or sold into that state. To model this cost, PSE used the Wood MacKenzie forecast of California CO_2 prices based on AB32.

Build and Retirement Constraints

PSE added constraints on different 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 the 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

Starting with the optimized, least cost Base Scenario portfolio, sensitivities change one resource assumption within the portfolio in order to isolate the effect of that resource change on the portfolio.

NOTE: The table in Figure 4-3 presents this information in abbreviated form.

A. Colstrip

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

BASELINE ASSUMPTION: Units 1 & 2 retire in 2022 and Units 3 & 4 remain in service into 2035.
SENSITIVITY 1 > Retire Units 1 & 2 in 2018.
SENSITIVITY 2 > Retire Units 3 & 4 in 2025.
SENSITIVITY 3 > Retire Units 3 & 4 in 2030.

B. Thermal Retirement

This sensitivity examines whether it would be cost effective to accelerate retirement of PSE's existing gas plants.

BASELINE ASSUMPTION: Optimal portfolio from the Base Scenario
SENSITIVITY 1 > Retire baseload gas plants early.

C. No New Thermal Resources

This sensitivity looks at the cost of filling all future supply-side portfolio resource needs with resources that emit no carbon.

BASELINE ASSUMPTION: Fossil fuel generation is an option in the model.
SENSITIVITY 1 > Renewable resources, energy storage and DSR are the only options for future resources.

D. Stakeholder-requested Alternative Resource Costs

This sensitivity models changes to the generic resource cost assumptions based on recommendations from IRP stakeholders.

BASELINE ASSUMPTION: PSE cost estimates for generic supply-side resources.

SENSITIVITY 1 > Lower cost for recip peakers: $1,105 per kW without oil backup, $1,257 per kW with oil backup

SENSITIVITY 2 > Higher thermal resource costs, based on the 2015 IRP capital cost estimates. Numbers are in 2016 dollars and include 30 percent owner's costs consistent with the 2017 IRP instead of the 40 percent owner's costs modeled in the 2015 IRP.

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

SENSITIVITY 3 > Lower wind and solar development cost (includes 30% owner's costs)

Wind: $1,478 per kW
Solar: $1,755 per kW

SENSITIVITY 4 > Apply more aggressive solar cost curve.

E. Energy Storage

This sensitivity examines the cost difference between a portfolio with energy storage and a portfolio without energy storage.

BASELINE ASSUMPTION: Batteries and pumped hydro included only if chosen economically.

SENSITIVITY 1 > Add 50 MW battery in 2023 instead of economically chosen peaker.

SENSITIVITY 2 > Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker.

F. Renewable Resources + Energy Storage

The baseline assumption is that the battery storage will be placed in an optimal location on the system to get the maximum transmission and distribution benefit. This sensitivity pair pairs 50 MW of battery storage with 200 MW of solar. If 75 percent of the energy used to charge the battery comes from a renewable resource, the battery storage will receive the same investment tax credit as the solar resource. However, locating the battery near the solar project in eastern Washington means it will no longer deliver the transmission and distribution benefit.

> **BASELINE ASSUMPTION:** Solar and batteries modeled individually.
> **SENSITIVITY 1 >** 200 MW solar bundled with 50 MW batteries

G. Electric Vehicle Load

This sensitivity examines how much electric vehicle charging loads will affect the resource plan forecast.

> **BASELINE:** IRP Base Demand forecast
> **SENSITIVITY >** Add forecasted electric vehicle load

The following three sensitivities test the impact of different demand-side resource configurations.

H. 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 (RCW 19.285).
> **SENSITIVITY 1 >** Existing DSR measures stay in place, but all future needs are met with supply-side resources.

I. Extended DSR Potential

The baseline assumption applies a 10-year ramp rate to all DSR identified as cost-effective in this IRP, meaning that all of these DSR measures are applied in the first decade of the study period. This sensitivity models future DSR measures that extend conservation benefits through the second decade of the study period.

> **BASELINE ASSUMPTION**: All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.
> **SENSITIVITY 1 >** Assume future DSR measures will extend conservation benefits through the second 10 years of the study period.

J. Alternate Residential Conservation Discount Rate

This sensitivity examines how using a societal discount rate on conservation savings from residential energy efficiency would impact cost-effective levels of DSR.

BASELINE ASSUMPTION: Assume the base discount rate.
SENSITIVITY 1 > Apply a societal discount rate to residential conservation savings.

The next five sensitivities test the impact of different wind resource configurations.

K. RPS-eligible Montana Wind

The baseline assumption is that Montana wind does not qualify as an RPS-eligible resource. To qualify under RCW 19.285, Montana wind would have to be dynamically scheduled into Washington state on a real-time basis without shaping or storage. "Dynamically scheduled" means PSE's balancing authority would have to balance real-time changes in wind energy output as if it were located in PSE's balancing authority. This would require coordination and agreement between Northwestern (the balancing authority where the wind plant would be built) and BPA (which would transmit the power to PSE). Complex studies on both systems would be required to determine if each transmission system could facilitate the dynamic transfer without adversely affecting the other transmission customers on its system. PSE formally requested assistance from BPA in April 2017, explaining the potential importance to PSE customers of finding a way to resolve this issue, and asking specifically: 1) what information and studies would be required to determine whether Montana wind qualified as a renewable resource under RCW 19.285, and 2) for any summary information concerning the information and studies, and/or whether tariffs or regulations would need to be addressed before qualifying studies could be conducted. Since that request was sent, BPA has announced its intention to convene with a forum with the State of Montana and other regional stakeholders to work on these issues, and PSE will participate and contribute to the identification and implementation of solutions concerning Montana wind. While Montana wind is not currently an RPS-eligible resource, this sensitivity examines whether Montana wind would be a cost-effective resource if it did qualify and therefore capture the extra 20 percent apprenticeship credit. If RPS-eligible Montana wind does not appear to be cost effective, a second sensitivity estimates how close its cost comes to other cost-effective resources.

BASELINE ASSUMPTION: Montana wind included only if economically chosen as a non-RPS resource
SENSITIVITY 1 > Add Montana wind in 2023 as an RPS-eligible resource instead of solar.
SENSITIVITY 2 > Montana wind tipping point analysis

L. Offshore Wind Tipping Point Analysis

This sensitivity examines how much the costs of offshore wind would need to decline before it appears to be a cost-effective resource.

BASELINE ASSUMPTION: Base Scenario portfolio
SENSITIVITY 1 > Offshore wind tipping point analysis to determine how much costs would have to drop to be cost effective compared to other resources.

M. Hopkins Ridge Repowering

Repowering refers to refurbishing or renovating a plant with more efficient, updated technology and equipment to qualify for Renewable Production Tax Credits under the PATH Act of 2015. Repowering would make the facility operate more efficiently and capture savings from the production tax credit. This sensitivity examines whether it would be cost effective to repower the Hopkins Ridge wind facility for the tax incentives and bonus RECs that would result.

BASELINE ASSUMPTION: Repowering Hopkins Ridge is not included in the portfolio.
SENSITIVITY 1 > Include repowering Hopkins Ridge in the portfolio to replace the existing facility.

Gas Sales 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, six alternatives were tested in the analyses.

Combination # 1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning November 2021, with expanded transport capacity on Enbridge/Westcoast Energy 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 believes it will be necessary to acquire Enbridge/Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity at Sumas.

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 November 2017 to October 2020 only. PSE believes that the vast majority of under- utilized firm pipeline capacity in the I-5 corridor will be absorbed by other new loads by the fall of 2020. Beyond October 2020, other long-term resources would be added to serve PSE 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 Enbridge/Westcoast. Availability is estimated beginning November 2021. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills 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-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

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 and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 5 – LNG-related Distribution Upgrade

This combination assumes completed construction and successful commissioning of the LNG peak-shaving facility for the 2019/20 heating season, providing 59.5 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Combination # 6 – Mist Storage and Redelivery

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 with significant additional volume contracting by other parties.

Combination # 7 – Swarr Propane/Air Upgrade

This is an upgrade to the existing Swarr LP-air facility. 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.

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: 2021, 2025, 2028 and 2033, 2037. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility’s upgrade and the LNG distribution system upgrade were made available in two year increments since these resources are PSE assets.

Gas Sales Sensitivities

A. 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 (RCW 19.285).
> **SENSITIVITY 1 >** Existing DSR measures stay in place, but all future needs are met with supply-side resources.

B. Resource Addition Timing Optimization

Two of the resource additions selected in most scenarios are within PSE’s control, the Swarr upgrade and the LNG-related distribution upgrade. This sensitivity examines how the timing of those PSE-controlled resource additions affect resource builds and portfolio costs.

> **BASELINE ASSUMPTION:** Swarr and the LNG-related distribution upgrade are offered every two years in the model.
> **SENSITIVITY 1 >** Allow these resources to be offered every year in the model.

C. Alternate Residential Conservation Discount Rate

This sensitivity examines how using a societal discount rate on conservation savings from residential energy efficiency would impact cost-effective levels.

BASELINE ASSUMPTION: Assume the base discount rate.

SENSITIVITY 1 > Apply a societal discount rate to residential conservation savings.

D. Additional Conservation

This sensitivity examines what happens if we add DSR above the levels found cost effective.

BASELINE ASSUMPTION: All cost-effective DSR per RCW 19.285.

SENSITIVITY 1 > Add two additional DSR bundles above those chosen as cost effective.

5

2017 PSE Integrated Resource Plan

Demand Forecasts

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 forecasts are designed for use in long-term resource planning.

Contents

1. OVERVIEW

Overall, the 2017 IRP Electric Base Demand Forecast before conservation for both energy and peak is lower than the 2015 IRP forecast. For energy, the average annual growth rate forecast in 2017 is 1.4 percent, compared to 1.7 percent in 2015. For peak demand, the average annual growth rate forecast in 2017 is 1.3 percent, compared to 1.6 percent in 2015. The forecast also shows higher near-term loads due to several large customers coming on line, and a lower forecast in later years, which reflects slower customer growth and the inclusion of 2015's unusually warm weather in the calculation of "normal"[1] weather assumptions.

The 2017 IRP Gas Base Demand Forecast before conservation for energy and peak loads is also lower than in the 2015 IRP. For energy, the average annual growth forecast in 2017 is 1.2 percent, compared to 1.7 percent in 2015. For peak demand, the the average annual growth rate forecast in 2017 is 1.4 percent, compared to 1.8 percent in 2015. Slower population growth has resulted in fewer new gas customers, and the inclusion of the 2015's unusually warm weather in calculating normal weather assumptions also reduced demand.

Base Forecast At 2037	Before DSR	After DSR
Electric Load (MW)	3,461	2,879
Electric Peak (MW)	6,511	5,664
Gas Load (Mdth)	120,970	113,100
Gas Peak (Mdth)	1,311	1,229

Demand is reduced significantly when forward projections of conservation savings are applied. However, it is necessary to start with forecasts that do not already include forward projections of conservation savings in order to identify the most cost-effective amount of conservation to include in the resource plan. Throughout this chapter, charts labeled "before DSR" include only demand-side resource (DSR) measures implemented ***before the study period begins in 2018***. Charts labeled "after applying DSR" include the cost-effective amount of DSR identified in the 2017 IRP.

To model a range of potential economic conditions, weather conditions and potential modeling errors in the IRP analysis, PSE also prepares Low and High forecasts in addition to the Base Forecast. The Low forecast models reduced population and economic growth compared to the Base Forecast; the High Forecast models higher population and economic growth compared to the Base Forecast.

1 / For the IRP analysis, normal weather is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2015.

2. ELECTRIC DEMAND FORECAST

Highlights of the base, high and low demand forecasts that PSE developed for the electric service area are presented below in Figures 5-1 through 5-4. The population and employment assumptions for all three forecasts are summarized beginning on page 5-32, and explained in detail in Appendix E, Demand Forecasting Models.

Only DSR measures implemented through December 2017 are included, since the demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio.

Electric Load Growth

In the 2017 IRP Base Demand Forecast, total load before DSR is expected to grow at a rate of 1.3 percent annually from 2018 to 2027 and 1.4 percent annually from 2027 to 2037, for an average annual growth rate of 1.4 percent over the 20-year study period. Total load is expected to grow from 2,681 aMW in 2018 to 3,461 aMW in 2037.

Residential and commercial loads are driving this growth; they represent 49 percent and 44 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 2017 IRP High Demand Forecast projects an average annual growth rate of 1.7 percent; the Low Demand Forecast projects 1.1 percent.

Figure 5-1: Electric Demand Forecast before DSR
Base, High and Low Scenarios (aMW)

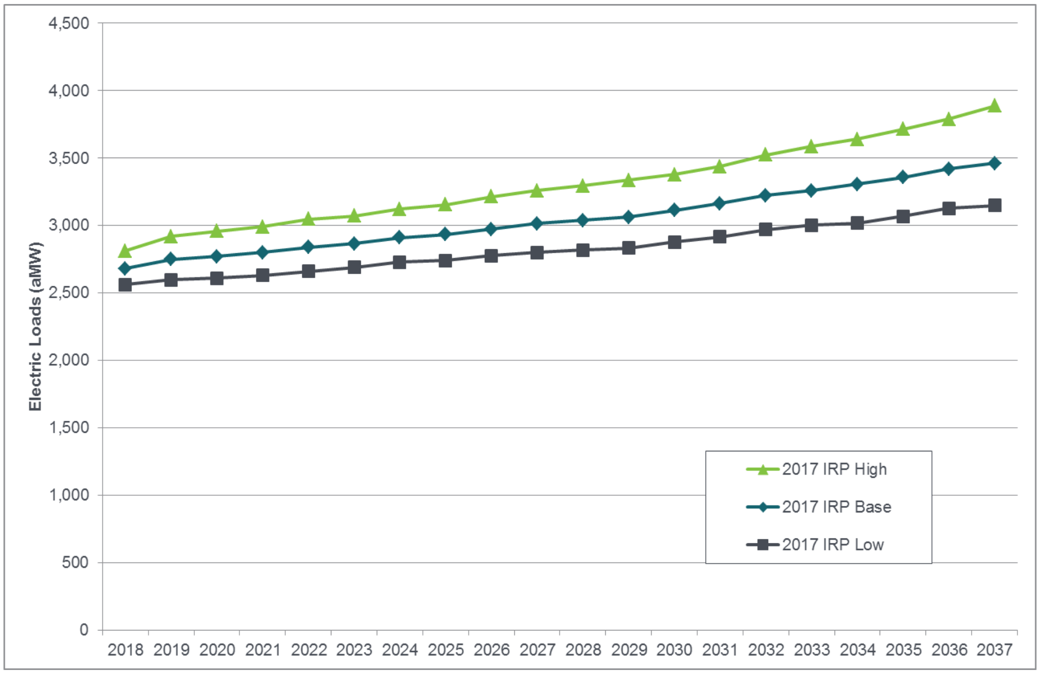


Figure 5-2: Electric Demand Forecast before DSR (Table)
Base, High and Low Scenarios

ELECTRIC DEMAND FORECAST SCENARIOS (aMW)						
Scenario	**2018**	**2022**	**2027**	**2032**	**2037**	**AARG 2018-2037**
2017 IRP Base Demand Forecast	2,681	2,837	3,013	3,221	3,461	1.4%
2017 IRP High Demand Forecast	2,812	3,048	3,257	3,525	3,886	1.7%
2017 IRP Low Demand Forecast	2,561	2,660	2,800	2,970	3,148	1.1%

Electric Peak Demand

The normal electric peak hour load is modeled using 23 degrees Fahrenheit as the design temperature. Since PSE is still a winter peaking utility, this peak usually occurs in December. The 2017 IRP Base Demand Forecast shows an average annual peak load growth of 1.3 percent and an increase in peak load from 5,098 MW to 6,511 MW between 2018 and 2037.

The 2017 IRP High Demand Forecast shows an average annual peak load growth of 1.6 percent, and the Low Demand Forecast shows a 1.1 percent annual peak load growth rate.

Figure 5-3: Electric Peak Demand Forecast before DSR
Base, High and Low Scenarios, Hourly Annual Peak (23 Degrees, MW)

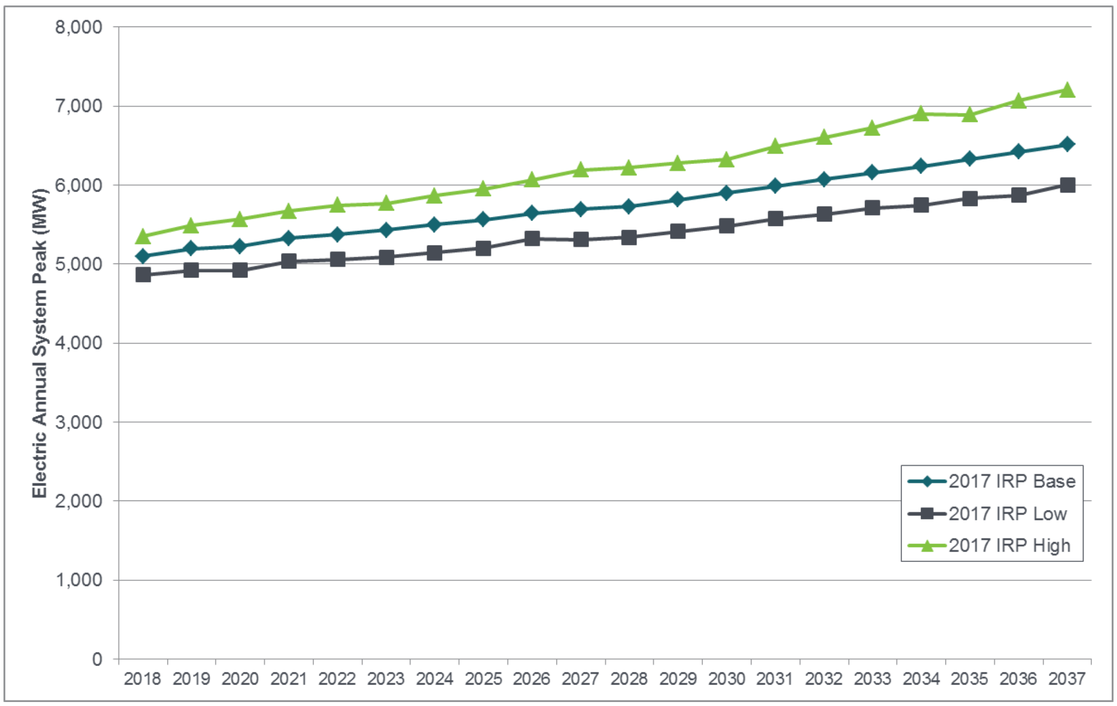


Figure 5-4: Electric Peak Demand Forecast before DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (23 Degrees, MW)

ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW)						
Scenario	2018	2022	2027	2032	2037	AARG 2018-2037
2017 IRP Base Demand Forecast	5,098	5,374	5,695	6,072	6,511	1.3%
2017 IRP High Demand Forecast	5,348	5,749	6,194	6,606	7,208	1.6%
2017 IRP Low Demand Forecast	4,867	5,062	5,308	5,629	6,001	1.1%

Peak demand in the 2017 IRP Electric Base Demand Forecast is lower than the 2015 IRP Base Demand Forecast due primarily to the lower population forecast which led to a lower customer forecast, and to higher retail rates leading to lower customer usage.

Figure 5-5: Electric Peak Demand Forecast before DSR,
2017 IRP Base Scenario versus 2015 IRP Base Scenario
Hourly Annual Peak (23 Degrees, MW)

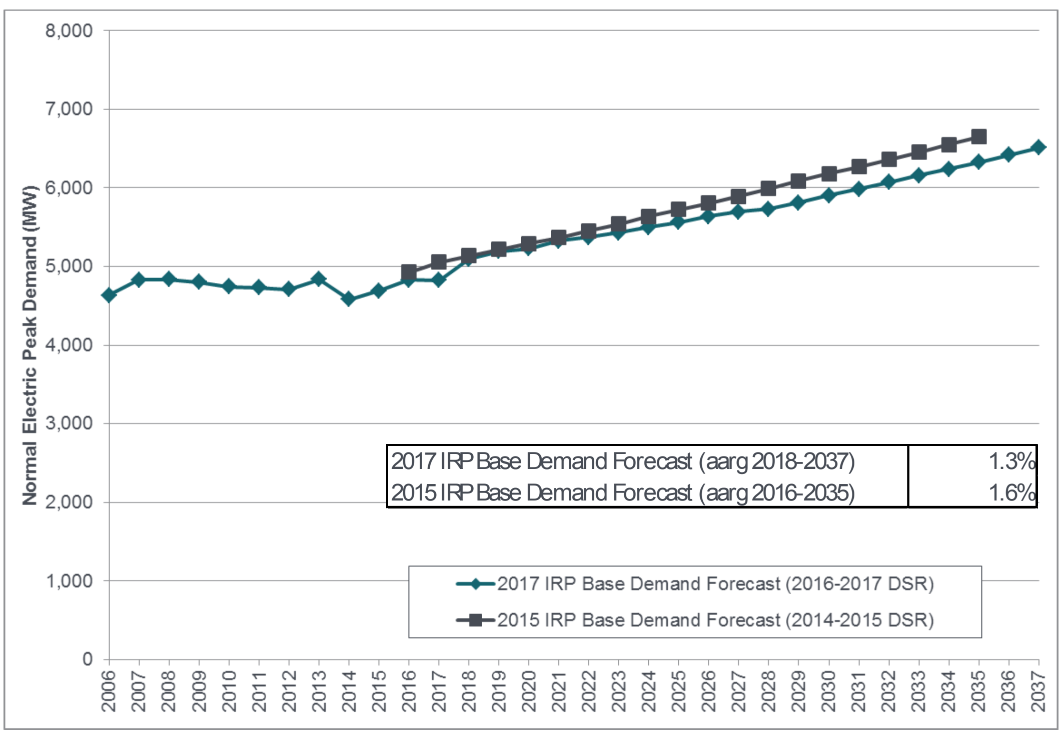


Illustration of Conservation Impacts

The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2016 and 2017, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2018 to 2037.

However, we also examine the effects of conservation on the system load and peak forecasts over the 20-year planning horizon. The load forecast net of conservation is used internally at PSE for financial planning and for transmission and distribution system planning. We apply the cost-effective demand-side resources identified in this IRP[2] to the Base Scenario load and peak forecasts for 2018 to 2037. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation is also applied for that period. The result is illustrated in Figures 5-6 and 5-7, below.

DSR IMPACT ON LOAD: When the DSR bundles chosen in the 2017 IRP portfolio analysis are applied to the load forecast:

- Total system demand is 2,657 aMW in 2018 increasing to 2,879 aMW in 2037, or an 0.4 percent growth rate per year.
- Average annual growth is -0.3 percent from 2018 to 2027 and 1.1 percent from 2027 to 2037. 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 DSR bundles chosen in the portfolio analysis are applied to the peak forecast:

- The system peak is 5,060 MW in 2018 increasing to 5,664 MW in 2037, or a 0.6 percent growth per year.
- From 2018 to 2027 peak loads are flat (average annual growth is 0.0 percent), and from 2027 to 2037 average annual growth is 1.1 percent. Again, peak load grows more slowly in the first 10 years when DSR is more heavily concentrated.

2 / For demand-side resource analysis, see Chapter 6, Electric Analysis, and Appendix J, Conservation Potential Assessment.

Figure 5-6: 2017 IRP Electric Base Demand Forecast (aMW), before DSR and after applying DSR

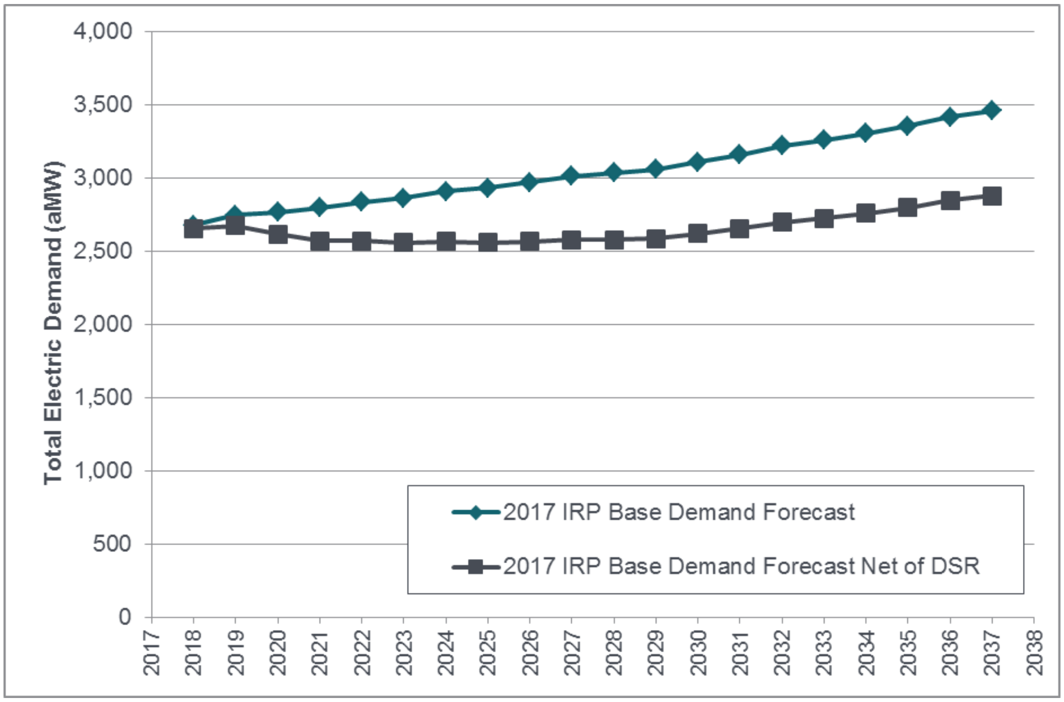
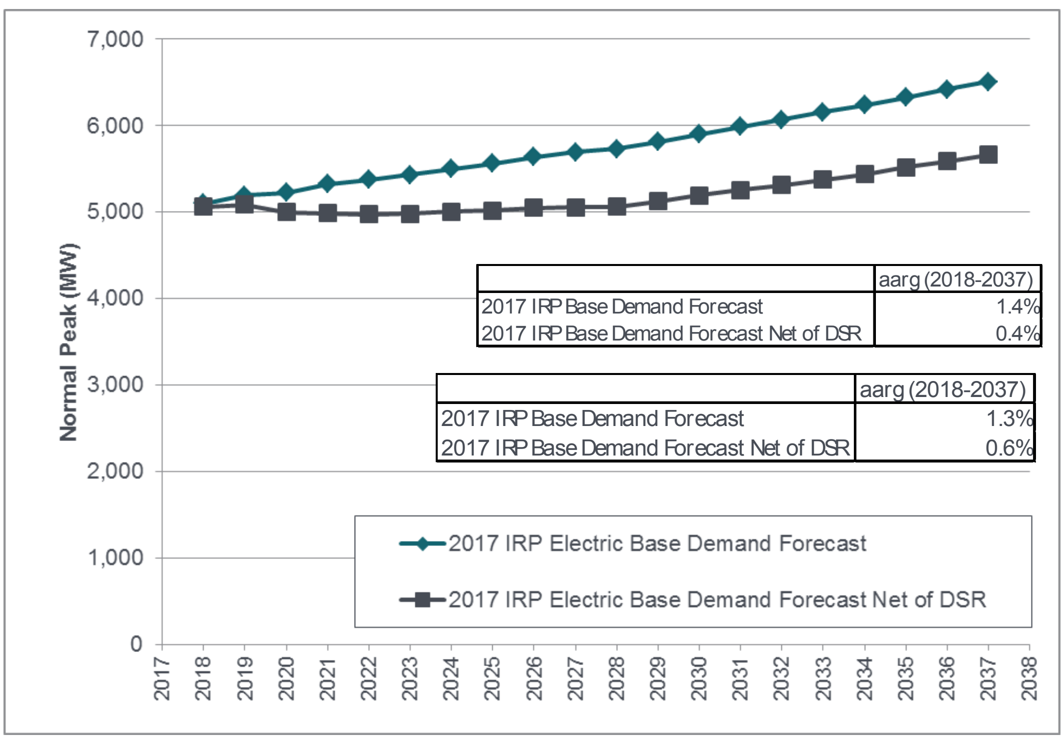


Figure 5-7: Electric Peak Base Demand Forecast (MW), before DSR and after applying DSR



Details of Electric Forecast

Electric Customer Counts

System-level customer counts are expected to grow by 1.2 percent per year on average, from 1.15 million customers in 2018 to 1.45 million customers in 2037. This is slightly lower than the average annual growth rate of 1.5 percent projected in the 2015 IRP Base Demand Forecast due to the lowered population forecast.

Residential customers are driving the customer count increase; they represent 88 percent of the PSE's electric customers in 2018. The next largest group, commercial customers, is expected to grow at an annual rate of 1.6 percent from 2018 to 2037. 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 5-8: December Electric Customer Counts by Class, 2017 IRP Base Demand Forecast

DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST						
Class	2018	2022	2027	2032	2037	AARG 2018-2037
Total	1,150,954	1,213,022	1,291,755	1,369,925	1,446,944	1.2%
Residential	1,011,079	1,064,616	1,131,808	1,197,449	1,261,057	1.2%
Commercial	130,424	139,048	150,671	163,279	176,764	1.6%
Industrial	3,366	3,277	3,172	3,069	2,971	-0.7%
Other	6,085	6,081	6,104	6,128	6,152	0.1%

Electric Load by Class

Over the next 20 years, the commercial sector is expected to contribute most to the total growth of system loads (60 percent). This is driven by the growth of commercial employment in the high tech sectors, which serve not only local but national and international markets. As the population increases, the need for commercial services such as health care, retail, education and other public services also increases.

Figure 5-9: Electric Demand by Class, 2017 IRP Base Demand Forecast before DSR

ELECTRIC LOAD BY CLASS, BASE DEMAND FORECAST (aMW)						
Class	2018	2022	2027	2032	2037	AARG 2018-2037
Total	2,681	2,837	3,013	3,221	3,461	1.4%
Residential	1,194	1,258	1,336	1,414	1,499	1.2%
Commercial	1,133	1,231	1,323	1,445	1,586	1.8%
Industrial	150	132	126	120	117	-1.3%
Other	10	9	8	7	7	-1.8%
Losses	196	207	220	235	253	1.4%

Electric Use per Customer

Residential use per customer before conservation 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 real electric rates. As the economy continues to grow steadily, commercial use per customer is expected to rise slowly due to higher employment levels and lower vacancy rates in the near term.

Figure 5-10: Electric Use per Customer, 2017 IRP Base Demand Forecast before DSR

ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh)						
Type	2018	2022	2027	2032	2037	AARG 2018-2037
Residential	10.4	10.4	10.4	10.4	10.5	0.04%
Commercial	76.1	78.1	77.4	78.0	79.1	0.20%
Industrial	389	353	348	342	343	-0.66%

Electric Customer Count and Load Shares by Class

Customer counts as a percent of PSE's total electric customers are shown in Figure 5-11. Load shares by class are shown in Figure 5-12. These tables show the flat growth trajectory of residential classes compared to the robust growth of commercial classes.

Figure 5-11: December Electric Customer Count Shares by Class, 2017 IRP Base Demand Forecast

ELECTRIC CUSTOMER COUNT SHARES BY CLASS, BASE DEMAND FORECAST		
Class	**Share in 2018**	**Share in 2037**
Residential	87.8%	87.2%
Commercial	11.3%	12.2%
Industrial	0.3%	0.2%
Other	0.5%	0.4%

Figure 5-12: Electric Load Shares by Class, 2017 IRP Base Demand Forecast

ELECTRIC LOAD SHARES BY CLASS, BASE DEMAND FORECAST		
Class	**Share in 2018**	**Share in 2037**
Residential	44%	43%
Commercial	42%	46%
Industrial	6%	3%
Other	0.4%	0.2%
Losses	7%	7%

Figure 5-13: PSE Electric Service Territory

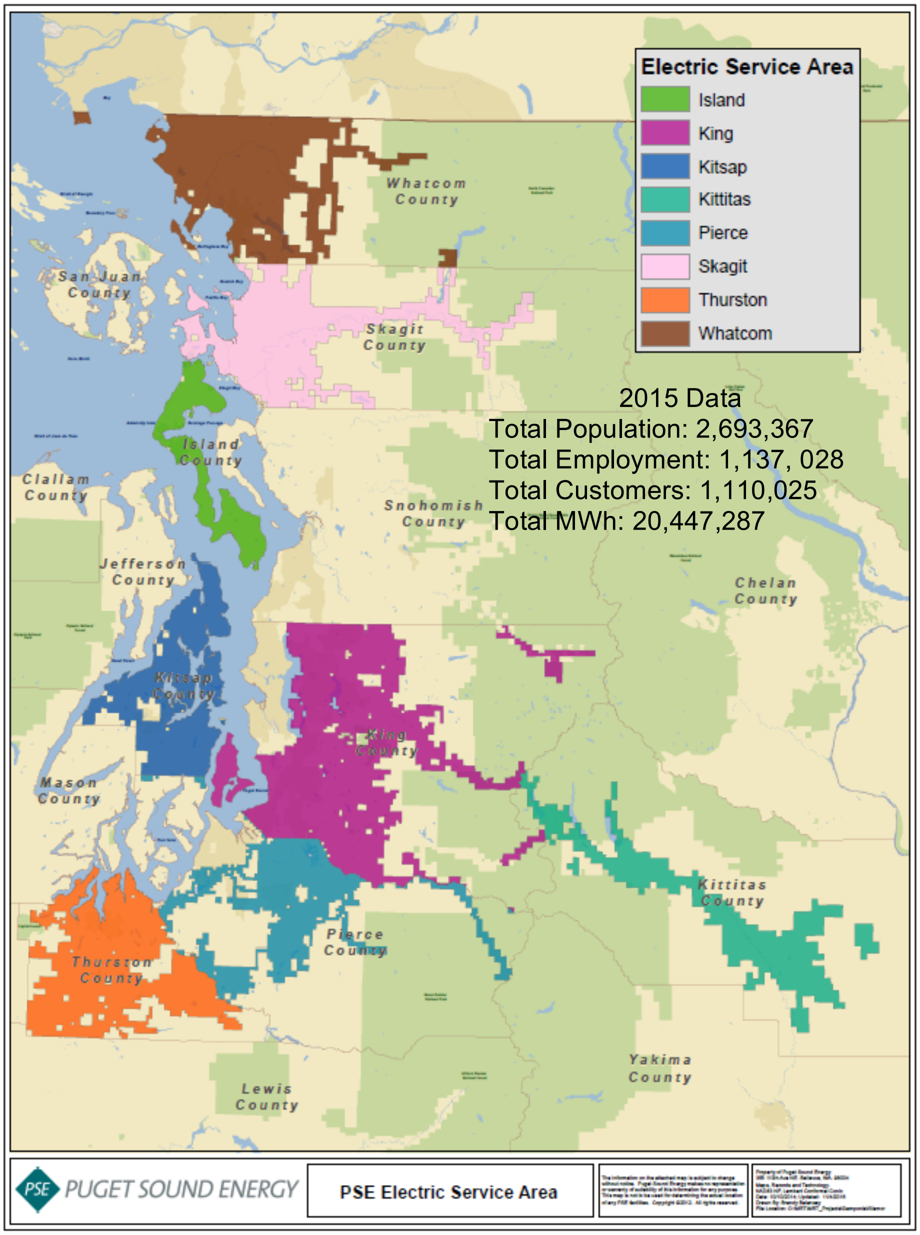


Figure 5-14: Electric Service Area, County Share as a Percent of PSE Total, 2015 Data

COUNTY	POPULATION	EMPLOYMENT	CUSTOMERS	SALES
King	48%	58%	49%	53%
Thurston	10%	10%	11%	11%
Pierce	15%	10%	10%	10%
Kitsap	10%	8%	11%	9%
Whatcom	8%	8%	9%	8%
Skagit	4%	4%	5%	6%
Island	3%	1%	3%	2%
Kittitas	2%	1%	1%	1%

3. GAS DEMAND FORECAST

Highlights of the base, high and low demand forecasts developed for PSE's gas sales service are presented below. The population and employment assumptions for all three forecasts are summarized on page 5-34, and explained in detail in Appendix E, Demand Forecasting Models.

Only demand-side resources implemented through December 2017 are included, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Gas Load Growth

The 2017 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 2017 IRP Base Demand Forecast, gas load is projected to grow 1.2 percent per year on average from 2018 to 2037; this would increase load from 96,808 Mdth in 2018 to 120,970 Mdth in 2037. This is lower than the annual growth rate of 1.7 percent in the 2015 IRP Base Demand Forecast.

The 2017 IRP High Gas Demand Forecast projects an average annual growth rate of 1.7 percent; the Low Demand Forecast projects a growth rate of 0.5 percent per year.

Figure 5-15: Gas Demand Forecast before DSR
Base, High and Low Scenarios, without Transport Load (Mdth)

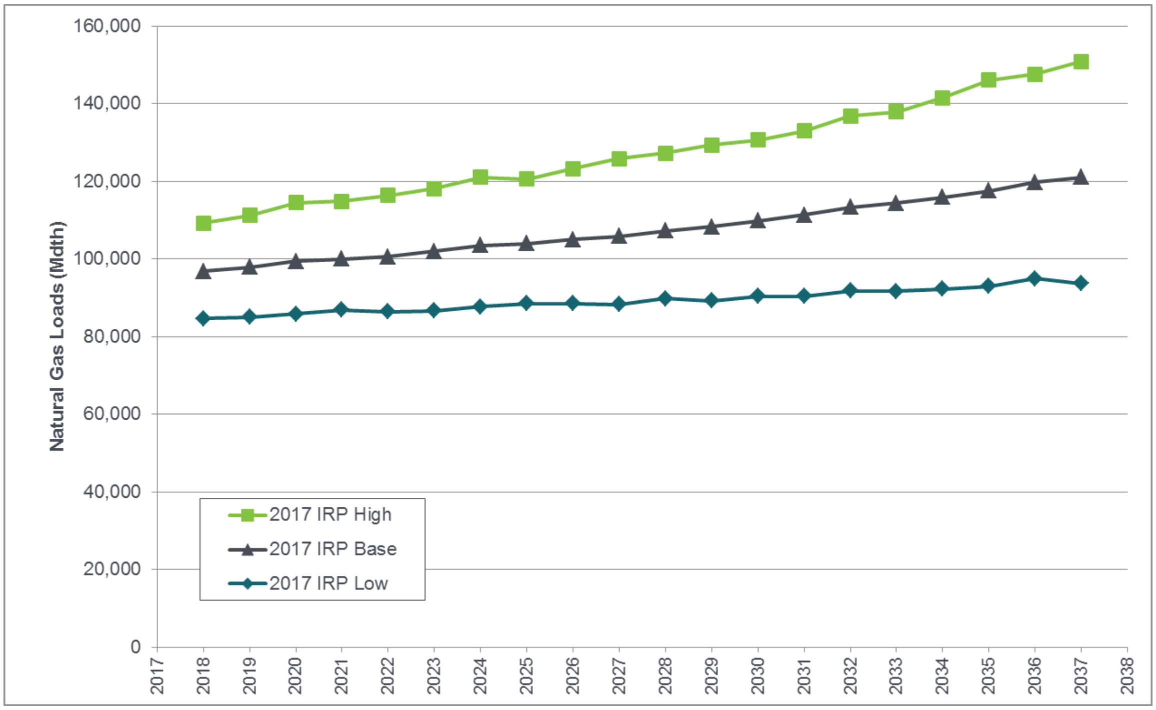


Figure 5-16: Gas Demand Forecast before DSR (Table)
Base, High and Low Scenarios without Transport Load (Mdth)

GAS LOAD FORECAST SCENARIOS (Mdth), WITHOUT TRANSPORT						
Scenario	2018	2022	2027	2032	2037	AARG 2018-2037
2017 IRP Base Demand Forecast	96,808	100,612	105,806	113,288	120,970	1.2%
2017 IRP High Demand Forecast	109,228	116,376	125,840	136,868	150,861	1.7%
2017 IRP Low Demand Forecast	84,673	86,395	88,275	91,779	93,603	0.5%

Gas Peak Demand

The gas design peak day is modeled at 13 degrees Fahrenheit average temperature for the day. Only firm sales customers are included when forecasting peak gas loads; transportation and interruptible customers are not included.

For peak gas demand, the 2017 IRP Base Demand Forecast projects an average increase of 1.4 percent per year for the next 20 years; peak demand would rise from 1,010 Mdth in 2018 to 1,311 Mdth in 2037. The High Demand Forecast projects a 1.7 percent annual growth rate, and the Low Demand Forecast projects 1.1 percent.

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 5-17: Gas Peak Day Demand Forecast before DSR
Base, High and Low Scenarios (13 Degrees, Mdth)

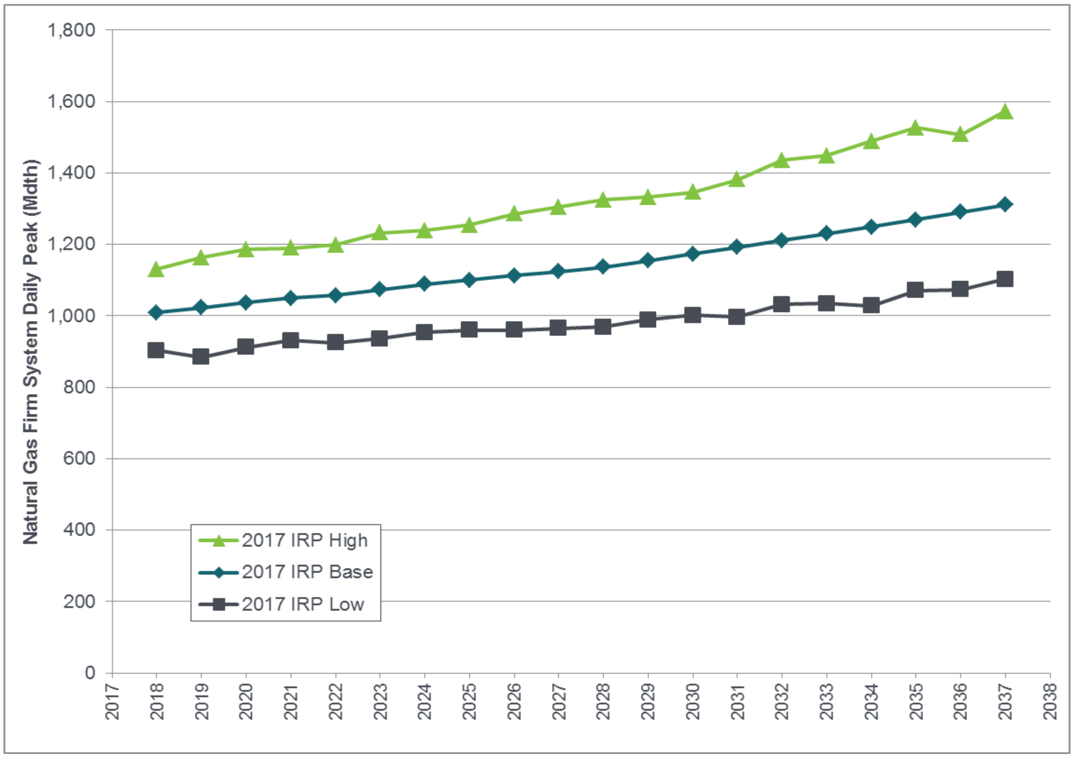


Figure 5-18: Gas Peak Day Demand Forecast before DSR (Table)
Base, High and Low Scenarios (13 Degrees, Mdth)

FIRM GAS PEAK DAY FORECAST SCENARIOS (Mdth)						
Scenario	**2018**	**2022**	**2027**	**2032**	**2037**	**AARG 2018-2037**
2017 IRP Base Demand Forecast	1,010	1,058	1,123	1,211	1,311	1.4%
2017 IRP High Demand Forecast	1,130	1,199	1,304	1,435	1,571	1.7%
2017 IRP Low Demand Forecast	903	925	965	1,031	1,102	1.1%

The 2017 IRP Base Demand growth rate is lower than the 2015 IRP Base Demand growth rate of 1.8 percent (2016 to 2035), mainly due to the lower customer count forecast.

Figure 5-19: Firm Gas Peak Day Forecast before DSR
2017 IRP Base Scenario versus 2015 IRP Base Scenario
Daily Annual Peak (13 Degrees, Mdth)

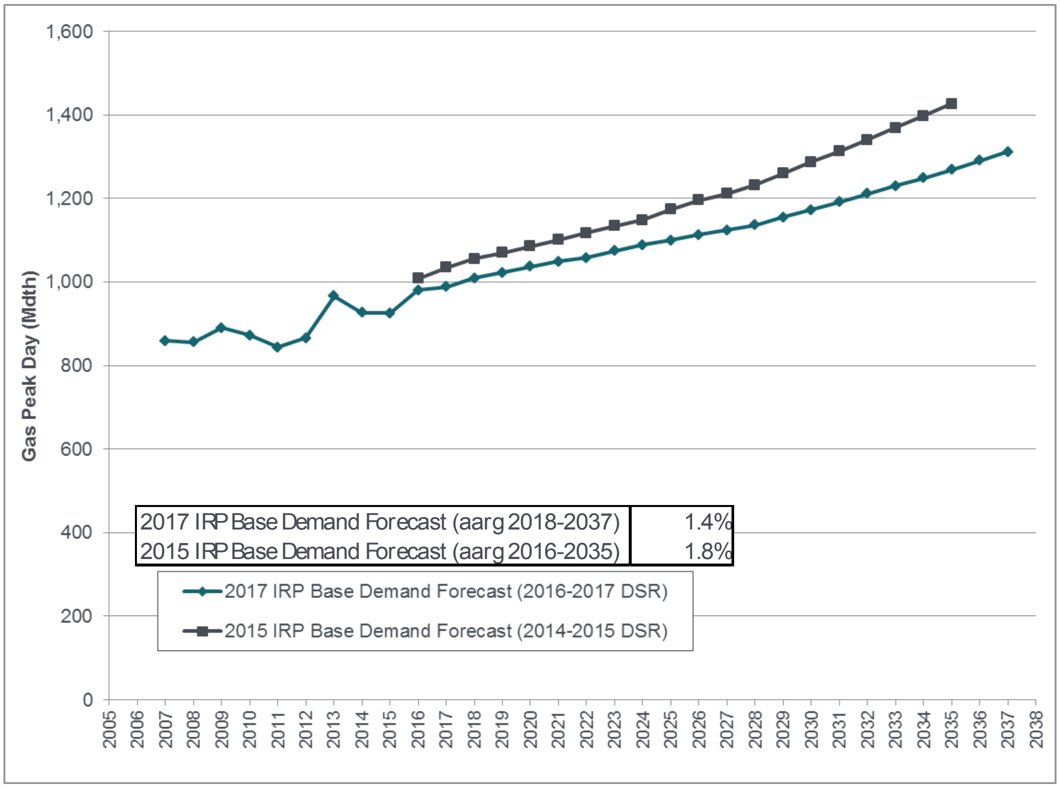


Illustration of Conservation Impacts

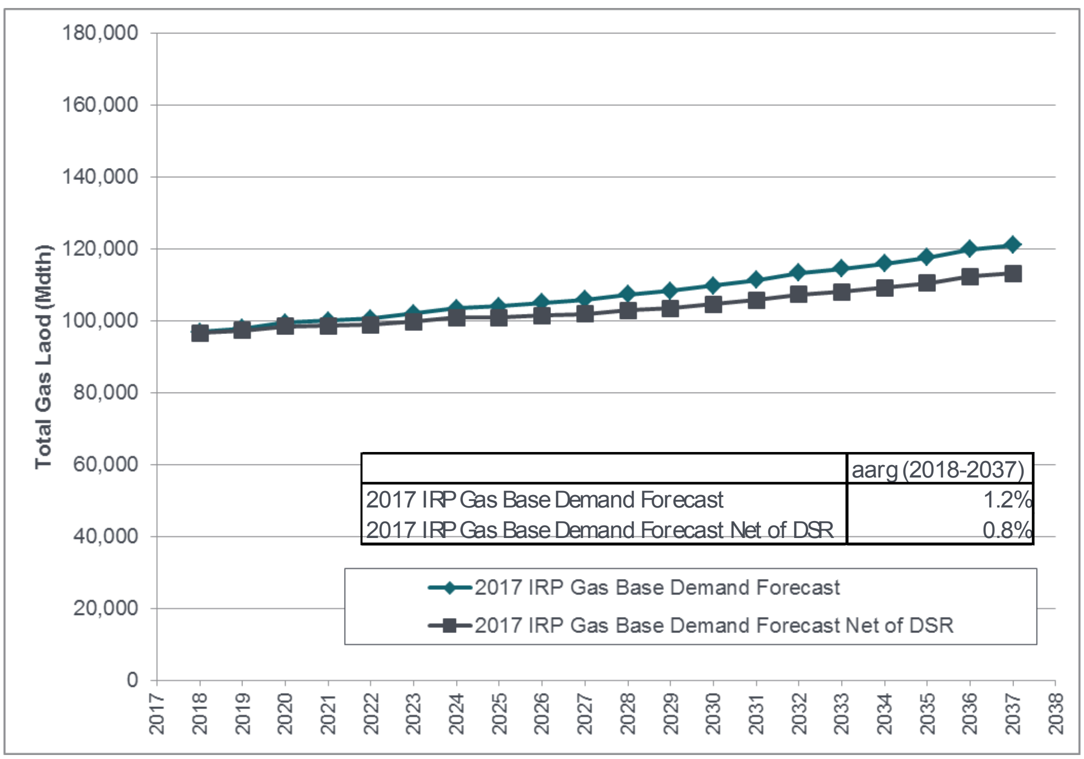
As explained at the beginning of the chapter, the gas demand forecasts include only demand-side resources implemented through December 2017, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of conservation on the system load and peak forecasts, the cost-effective amount of DSR determined in this IRP[3] is applied to the system load (without transport loads) and peak forecast for 2018 to 2037. This forecast is used internally at PSE for financial and system planning decisions.

3 / For demand-side resource analysis, see Chapter 7, Gas Analysis, and Appendix J, Conservation Potential Assessment.

When the DSR bundles chosen in the 2017 IRP portfolio analysis are applied:

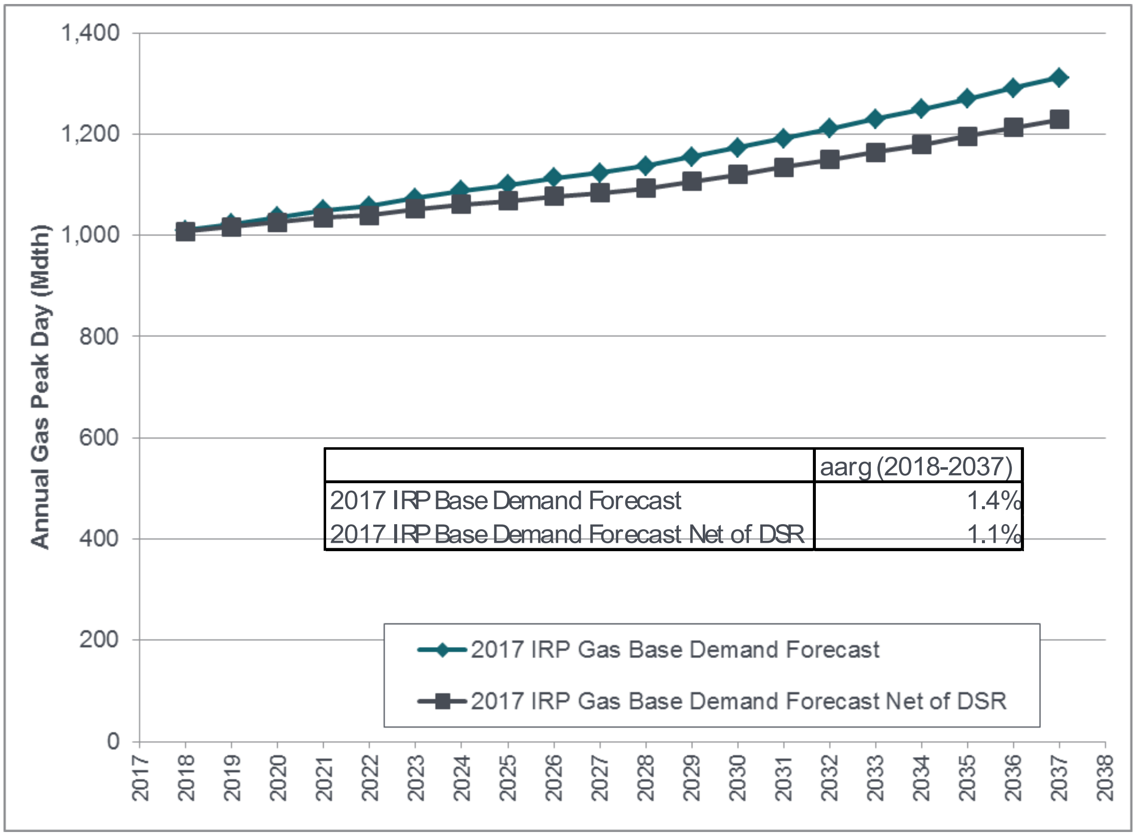
- System load (without transport but with losses) grows at an average annual rate of 0.6 percent from 2018 to 2027 and 1.1 percent from 2027 to 2037, or 0.8 percent per year over the next 20 years; volume rises from 96,808 Mdth in 2018 to 113,100 Mdth in 2037. Load grows more slowly in the first half 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 0.8 percent from 2018 to 2027 and 1.3 percent from 2027 to 2037, or 1.1 percent per year over the next 20 years; volume rises from 1,008 Mdth in 2018 to 1,229 Mdth in 2037. 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.

Figure 5-20: 2017 IRP Gas Base Demand Forecast, before DSR and after applying DSR



	aarg (2018-2037)
2017 IRP Gas Base Demand Forecast	1.2%
2017 IRP Gas Base Demand Forecast Net of DSR	0.8%

Figure 5-21: 2017 IRP Gas Peak Day Base Demand Forecast,
Before DSR and after applying DSR



Details of Gas Forecast

Gas Customer Counts

The Base Demand Forecast projects natural gas customer counts will increase at a rate of 1.3 percent per year on average between 2018 and 2037, reaching almost 1.06 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 1.9 percent growth rate projected in the 2015 IRP (2016 to 2035).

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 1.5 percent from 2018 to 2037. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Figure 5-22: December Gas Customer Counts by Class, from 2017 IRP Base Demand Forecast

DECEMBER GAS CUSTOMER COUNTS BY CLASS FROM 2017 IRP BASE DEMAND FORECAST						
Customer Type	**2018**	**2022**	**2027**	**2032**	**2037**	**AARG 2018-2037**
Residential	768,811	811,203	865,093	921,391	982,574	1.3%
Commercial	56,374	59,802	64,263	69,027	74,146	1.5%
Industrial	2,313	2,201	2,071	1,947	1,832	-1.2%
Total Firm	827,499	873,206	931,427	992,365	1,058,551	1.3%
Interruptible	266	235	206	184	167	-2.4%
Total Firm & Interruptible	827,765	873,441	931,633	992,549	1,058,718	1.3%
Transport	224	224	224	224	224	0.0%
System Total	827,989	873,665	931,857	992,773	1,058,942	1.3%

Gas Use per Customer

Residential use per customer before conservation is declining slightly, showing a -0.2 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 and is expected to decline at an annual rate of -0.3 percent.

Figure 5-23: Gas Use per Customer, 2017 IRP Gas Base Demand Forecast before DSR

USE PER CUSTOMER (THERMS) FROM 2017 IRP GAS BASE DEMAND FORECAST						
Customer	**2018**	**2022**	**2027**	**2032**	**2037**	**AARG 2018-2037**
Residential	798	783	765	761	762	-0.2%
Commercial	4,887	4,958	5,032	5,166	5,313	0.4%
Industrial	11,296	10,264	10,948	11,007	10,761	-0.3%

Gas Load by Class

Total system load, including transport load, is expected to increase at a rate of 0.8 percent annually between 2018 and 2037. Residential loads, which represent 51 percent of load in 2018, are expected to increase by 1.0 percent annually during the forecast period. Commercial loads, which represent 23 percent of 2018 load, are expected to increase 1.9 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 5-24: Gas Loads by Class (Mdth), 2017 IRP Gas Base Demand Forecast before DSR

LOAD (Mdth) BY CLASS FROM 2017 IRP GAS BASE DEMAND FORECAST						
Class	2018	2022	2027	2032	2037	AARG 2018-2037
Residential	61,449	63,571	66,264	70,476	74,846	1.0%
Commercial	27,930	30,058	32,717	36,162	39,708	1.9%
Industrial	2,632	2,288	2,294	2,176	1,999	-1.4%
Total Firm	92,011	95,917	101,275	108,814	116,553	1.3%
Interruptible	4,313	4,192	4,002	3,907	3,812	-0.6%
Total Firm and Interruptible	96,324	100,109	105,277	112,722	120,365	1.2%
Transport	23,859	22,522	20,822	20,134	19,555	-1.0%
System Total before Losses	120,183	122,630	126,099	132,856	139,920	0.8%
Losses	604	616	634	668	703	0.8%
System Total	120,787	123,247	126,732	133,523	140,623	0.8%

Gas Customer Count and Load Shares by Class

Customer counts as a percent of PSE's total gas customers are shown in Figure 5-25. Load shares by class are shown in Figure 5-26.

Figure 5-25: Gas Customer Count Shares by Class, 2017 IRP Base Demand Forecast

GAS CUSTOMER COUNT SHARES BY CLASS, BASE DEMAND FORECAST		
Class	**Share in 2018**	**Share in 2037**
Residential	92.8%	92.8%
Commercial	6.8%	7.0%
Industrial	0.3%	0.2%
Interruptible	0.03%	0.02%
Transport	0.03%	0.02%

Figure 5-26: Gas Load Shares by Class, 2017 IRP Base Demand Forecast

GAS LOAD SHARES BY CLASS, BASE DEMAND FORECAST		
Class	**Share in 2018**	**Share in 2037**
Residential	50.9%	53.2%
Commercial	23.1%	28.2%
Industrial	2.2%	1.4%
Interruptible	3.6%	2.7%
Transport	19.8%	13.9%
Losses	0.5%	0.5%

Figure 5-27: PSE Gas Service Territory

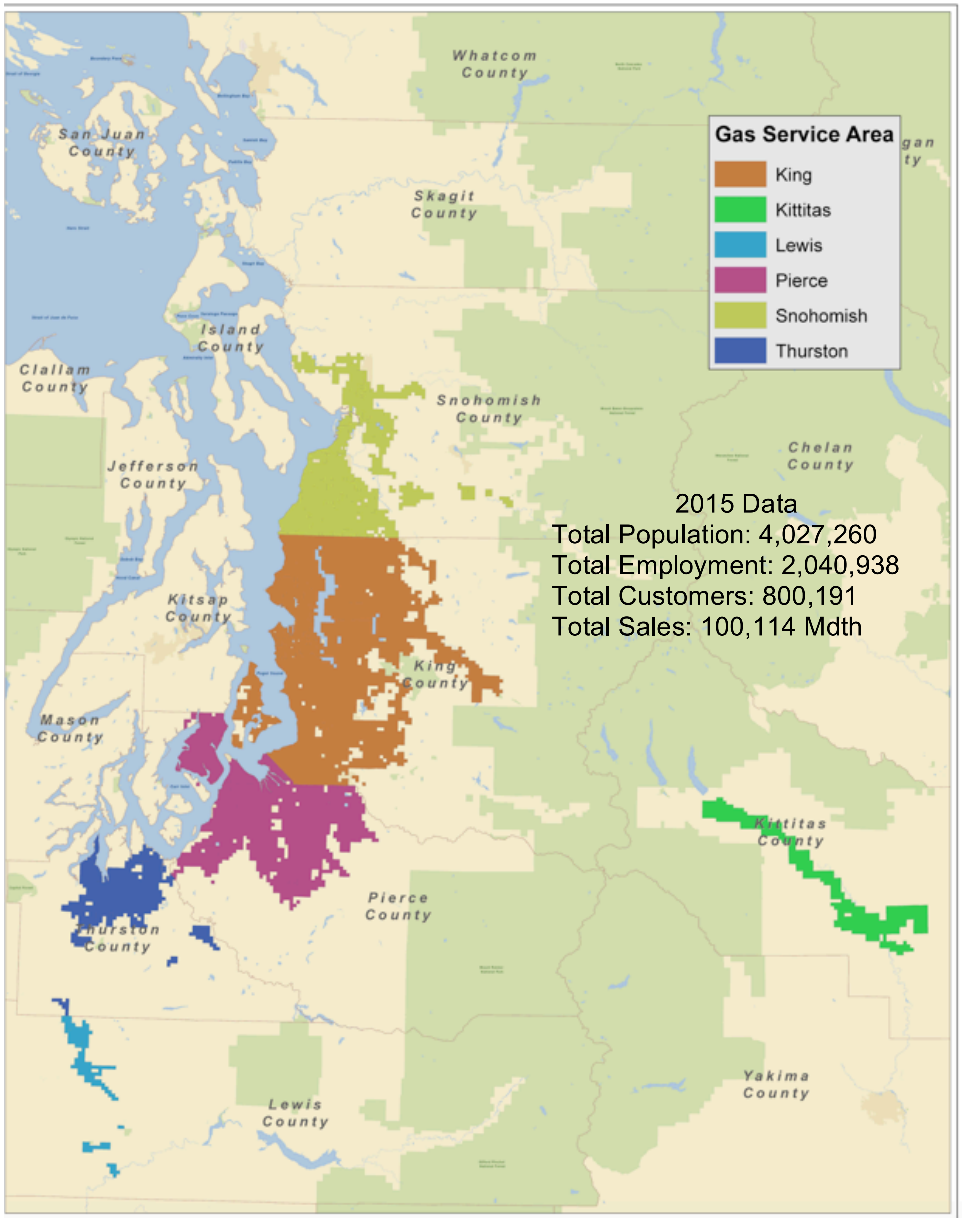


Figure 5-28: Gas Service Territory, County Share as a Percent of PSE Total, 2015 Data

COUNTY	POPULATION	EMPLOYMENT	CUSTOMERS	SALES
King	51%	64%	57%	57%
Pierce	21%	15%	19%	22%
Snohomish	19%	14%	17%	15%
Thurston	7%	5%	6%	5%
Lewis	2%	1%	1%	1%
Kittitas	1%	1%	<1%	<1%

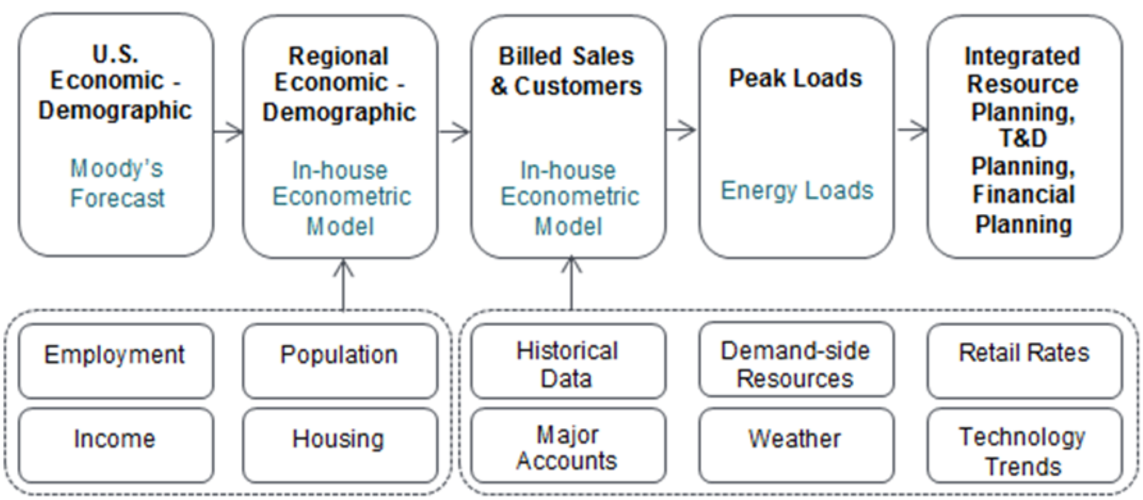
4. METHODOLOGY

Forecasting Process

PSE has made significant updates to the load forecast inputs and equations since the 2015 IRP, which enable us to make more accurate projections of customer counts, use per customer and load shapes. These innovations and updates are described starting on page 5-28.

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 used in the model are built up from county-level or MSA (metropolitan statistical area)-level information from various sources. This economic and demographic information is combined with other PSE internal information to produce energy and peak load forecasts for the service territory. The load-forecasting process is illustrated in Figure 5-29, and the input data sources are listed in Figure 5-30.

Figure 5-29: PSE Load Forecasting Process



Electricity and natural gas are inputs into different end uses.

- 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 (customers purchasing their power not from PSE but from third-party 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.

Econometric/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. Peak system loads are also projected by examining the historical relationship between actual peaks, temperature at peaks, and also the economic and demographic impacts on system loads.

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

High and Low Scenarios

PSE also develops high and low growth scenarios by performing 250 stochastic simulations of PSE's economic and demographic model combined with stochastic draws of weather. These simulations reflect variations in key regional economic and demographic variables such as population, employment and income, and also a historic weather scenario instead of "normal weather." For the IRP analysis, normal weather is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2015. The historic weather scenarios in each of the 250 simulations use 20 years of continuous historic weather randomly drawn between 1929 and 2015. The low and high scenarios represent the 5th and 95th percentile of the 250 simulations, respectively. More detailed discussion of the stochastic simulations is presented in Appendix E, Demand Forecasting Models.

Figure 5-30: 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	U.S. Bureau of Labor Statistics (BLS) www.bls.gov Puget Sound Regional Council (PSRC) www.psrc.org
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department, using data from Quarterly Census of Employment and Wages https://fortress.wa.gov/
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	
Population	U.S. Bureau of Economic Analysis (BEA) / WA State Office of Financial Management (OFM) www.ofm.wa.gov
Households, single- and multi-family	U.S. Census www.censtats.census.gov
Household size, single- and multi-family	
Housing permits, single- and multi-family	U.S. Census / Puget Sound Regional Council (PSRC) / City Websites / 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	

Updates to Inputs and Equations

PSE has made significant updates to the load forecast inputs and equations since the 2015 IRP. These updates are summarized below.

MODEL SELECTION TOOL. In conjunction with a University of Washington econometric consultant, PSE developed a model selection tool to develop a set of key drivers that contribute most to explaining the changes in use per customer or customer additions in the historical period. For example, the model selection tool was used to test different base temperatures for the heating degree day (HDD) and cooling degree day (CDD), economic and demographic variables, seasonal or monthly variables, dummy variables, autoregressive moving average (ARMA) terms, and polynomial distributed lag terms and orders.

SERVICE TERRITORY POPULATION AND EMPLOYMENT. The 2015 IRP used county-level population, employment and housing permit growth to predict customer additions and load growth for counties within the service territory. The 2017 IRP removes population and employment from non-PSE areas within those counties to reflect actual PSE service territory population and employment growth more accurately.

RESIDENTIAL ELECTRIC CUSTOMER ADDITIONS. The 2017 IRP uses total households as an explanatory variable for residential electric customer additions instead of total single- and multi-family housing permits, as in the 2015 IRP. The amount of multi-family housing permits in PSE's service territory has increased, but the monthly number of multi-family housing permits can be quite volatile, and therefore add more volatility to the customer forecast. At this time, growth in total households is a more stable indicator of long-term growth.

GAS CUSTOMER ADDITIONS. The 2017 IRP calculates gas customer additions using single-family housing permits as an explanatory variable instead of using total housing permits (single- and multi-family). Most of the new gas customers in PSE's service territory are still in single-family houses, but growth in small commercial customers also needs to be monitored.

RETAIL ELECTRIC FORECAST. The 2017 IRP smooths the retail rates forecast for the electric forecast to the rolling 12-month average of retail rates. This reflects the fact that while customers experience seasonal fluctuations in their retail rate, they tend to respond more to their total bill than the actual electric rates. This also removes the impact of seasonality on price per kWh.

MONTHLY BILLING CYCLE DEGREE DAY CALCULATION. The 2015 IRP used a generic degree day calculation to match up billing cycle data with the weather that occurred during that monthly billing cycle. The 2017 IRP uses PSE's actual 21 billing cycles to calculate a more precise degree day for each monthly billing cycle. The 2017 IRP also uses historical data to weight the degree day calculation based on the amount of load that occurs in each cycle within each month.

MONTHLY LOAD SHAPE. In the 2017 IRP, the monthly load shape is only applied to the years 2016 to 2018. Beyond 2018 the load shape is not applied. This allowed for shaping trends based on the historical data to be incorporated in the long-term forecast.

CONDITIONED SALES. Billing errors or back-billing can be present in recorded or "booked" billed sales. "Conditioned" sales correct for errors in billing and reallocate sales into the month where they occurred. The 2017 IRP uses conditioned sales instead of booked sales to create a better correlation between temperature, economic factors, and amount of energy or natural gas used.

LARGE VOLUME AND FIRM TRANSPORT GAS CUSTOMERS. The 2013 update to PSE's billing system made it difficult to determine the number of customers that had firm gas service in addition to interruptible or transport gas service. These customers are now counted based on usage in the last 6 months, instead of estimating their number based on historical data.

5. 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 long-term energy demand. While the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating/cooling, water heating, lighting, cooking, dishwashing/clothes washing and various electric plug loads. The growth in residential building stock therefore directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting and for various plug loads. Energy is also in important input into many industrial production processes. Economic activities in the commercial and industrial sectors are therefore important indicators for the overall trends in energy consumption.

National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, PSE's IRP forecast begins with assumptions about what is happening in the broader U.S. economy. The U.S. economy has established a steady, positive growth path; however, recovery from the effects of the 2008 recession has been modest compared to the strong recovery cycles experienced after prior recessions. Relative to the 2015 IRP economic forecasts, the U.S. economy is expected to grow steadily but more modestly in the 2017 IRP as a result of modest international economic growth and slowing U.S. population growth in the long term. Near term, however, the employment growth rate is expected to be slightly more robust relative to the 2015 IRP projections, leading to slightly faster near-term employment growth in parts of the PSE service territory.

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 March 2016 Moody's forecast was used for this IRP.

Moody's forecast calls for:

- U.S. GDP to continue growing modestly from the past recession, reaching 3 percent in 2017. This is a slower economic recovery than the Moody's forecast used in the 2015 IRP of nearly 4 percent GDP growth by 2015. Moody's forecasts of economic recovery have been tempered over the last few years by lower GDP growth rates.
- Average annual population growth of 0.66 percent for 2018-2037. This is down from the 0.76 percent growth rate Moody's forecast in the 2015 IRP for 2016-2035.

Slower population growth is attributed to lower birth rates due to an aging population and lower international migration now that developing countries' economies are growing faster than they have in the past.

Economic growth could slow if demand from China and Euro Zone economies continues to slow; if the Federal Reserve becomes aggressive in its interest rate setting; if international trade policies become more protectionist; or if geopolitical tensions increase, especially in Eastern Europe or the Middle East. Alternatively, if U.S. and international growth rates continue to diverge, the U.S. could be more attractive to domestic investors. Low oil prices could spur spending in the short term but weigh on U.S. oil companies in the long term. However, many believe that the U.S. economy will be able to withstand these threats and continue to follow a steady, positive growth path.

Regional Economic Outlook

PSE is the largest investor owned utility in Washington; it and provides gas services to almost 60 percent of state's population and electric services to about 40 percent of the state's population. Within PSE's service territory, demand growth is uneven. Most of the economic growth is driven by the growth in the high tech or information technology sectors, and this growth is concentrated in King County, which accounts for half or more of the system's electric and gas sales demand today. Other counties are growing, but slowly; most have yet to reach their pre-recession population or employment growth rates.

PSE prepares regional economic and demographic forecasts using econometric models whose primary inputs are the macroeconomic forecasts of the United States plus historical economic data for the counties in PSE's service area.

Electric Scenario Outlooks

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2017 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate (aarg) of 0.8 percent between 2018 and 2037, which is slightly faster than the annual growth rate of 0.7 percent forecasted in the 2015 IRP.
- Local employers are expected to create about 320,000 total jobs between 2018 and 2037 as compared to about 297,000 jobs forecasted in the 2015 IRP, mainly driven by growth in the commercial sectors.
- Manufacturing employment is expected to decline by 0.3 percent annually on average between 2018 and 2037 due to the outsourcing of manufacturing processes to lower wage states or countries, and also due to the continuing trend of capital investments that create increases in productivity.
- An inflow of more than 590,000 new residents (by birth or migration) is expected to increase PSE's electric service territory population to more than 4.6 million by 2037, for an average annual growth rate of 0.7 percent. This is lower than the 2015 IRP forecast, which projected an average annual population growth of 0.9 percent, which would have resulted in almost 4.8 million service territory residents by 2035.

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. Also, other prominent high technology companies are beginning to establish or have already established their presence in the Puget Sound area. 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.

HIGH SCENARIO OUTLOOK. For the High Electric Demand Forecast scenario, population grows by 0.8 percent annually from 2018 to 2037, and employment grows by 1.3 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Electric Demand Forecast scenario, population grows by 0.6 percent annually from 2018 to 2037. Employment grows 0.3 percent annually from 2018 to 2037.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 5-31 and 5-32.

Figure 5-31: Population Growth, Electric Service Area

POPULATION GROWTH, ELECTRIC SERVICE AREA (1,000s)						
Scenario	2018	2022	2027	2032	2037	AARG 2018-2037
2017 IRP Base Demand Forecast	4,031	4,187	4,363	4,509	4,622	0.7%
2017 IRP High Demand Forecast	4,033	4,214	4,414	4,571	4,698	0.8%
2017 IRP Low Demand Forecast	3,961	4,096	4,250	4,375	4,471	0.6%

Figure 5-32: Employment Growth, Electric Service Area

EMPLOYMENT GROWTH, ELECTRIC SERVICE AREA (1,000s)						
Scenario	2018	2022	2027	2032	2037	AARG 2018-2037
2017 IRP Base Demand Forecast	2,089	2,156	2,236	2,320	2,409	0.8%
2017 IRP High Demand Forecast	2,193	2,336	2,476	2,619	2,784	1.3%
2017 IRP Low Demand Forecast	1,973	1,989	2,000	2,040	2,105	0.3%

Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Gas Demand Forecast scenario, population grows by 1.0 percent annually from almost 4.2 million people in 2018 to 5 million people by 2037. Employment is expected to grow by 1.3 percent annually from 2018 to 2037.

HIGH SCENARIO OUTLOOK. For the High Gas Demand Forecast scenario, population grows by 1.1 percent annually from 2018 to 2037, and employment grows by 1.9 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Gas Demand Forecast scenario, population grows by 0.9 percent annually from 2018 to 2037. Employment grows 0.7 percent annually from 2018 to 2037.

The Base, High and Low population and employment forecasts for PSE's gas sales service area are compared in Figures 5-33 and 5-34.

Figure 5-33: Population Growth, Gas Service Area

POPULATION GROWTH, GAS SERVICE AREA (1,000s)						
Scenario	2018	2022	2027	2032	2037	AARG 2018-2037
2017 IRP Base Demand Forecast	4,189	4,392	4,633	4,852	5,049	1.0%
2017 IRP High Demand Forecast	4,213	4,442	4,713	4,967	5,203	1.1%
2017 IRP Low Demand Forecast	4,155	4,330	4,541	4,722	4,887	0.9%

Figure 5-34: Employment Growth, Gas Service Area

EMPLOYMENT GROWTH, GAS SERVICE AREA (1,000s)						
Scenario	2018	2022	2027	2032	2037	AARG 2018-2037
2017 IRP Base Demand Forecast	2,187	2,313	2,467	2,628	2,801	1.3%
2017 IRP High Demand Forecast	2,265	2,460	2,694	2,960	3,266	1.9%
2017 IRP Low Demand Forecast	2,133	2,200	2,272	2,354	2,431	0.7%

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 customer choices about the efficiency level of newly acquired appliances, how they are used, 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 2018 and 2037, nominal retail electric rates will grow at an average annual rate of 2.1 percent, which is higher than the 1.1 to 1.3 percent rate increase modeled in the 2015 IRP. However, the growth of retail electric rates is expected to trail inflation rates of 2.5 percent per year.

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 higher power costs compared to the 2015 IRP, hence the higher growth rate assumed here.

Gas Retail Prices

PSE expects nominal retail gas rates to rise between 2.8 percent and 3.1 percent per year between 2018 and 2037, depending on the customer class. This is slightly more than the long-term inflation rate of 2.5 percent. Gas prices for residential and commercial customers are higher in this forecast compared to the forecast in the 2015 IRP; interruptible and transport classes have similar or slightly higher retail rates and industrial rates are slightly lower.

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 2016 to 2020 period as of September 18, 2015 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 2015. 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 is 7.3 percent, compared to 6.9 percent in the 2015 IRP. The gas loss factor in this IRP is 0.5 percent, compared to 0.8 percent in the 2015 IRP.

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 291 MW to demand over the next 7 years for the electric system as a whole. King County has the most additions.

Block load additions are ramped into the forecast and then ramped out when population and employment have grown enough to account for these additions. This avoids double counting block load additions.

The electric forecast includes the following load additions:

- 109 MW of commercial load additions are expected between 2016 and 2018, and 67 MW between 2019 and 2022. Approximately 2.1 MWs of these additions are expected for horticultural lighting.
- Residential additions are expected to be 36 MW between 2016 and 2018, and 18 MW between 2019 and 2022.
- Expected industrial additions are 56 MW before 2019 and 5 MW between 2019 and 2022.

The gas forecast includes the following block load additions:

- 0.6 Mdth per day is added for transport customers.
- 1.5 Mdth per day is added for commercial customers.

Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2017 IRP Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2017, this adds 27.6 Mdth to the forecast. This load is expected to grow at an average annual rate of 2.0 percent, based on the Annual Energy Outlook 2015 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. Electric vehicle loads, which are expected to increase in the future, will also be treated in the IRP modeling process.

Interruptible Loads

PSE has 163 electric interruptible customers; five of these are commercial and industrial customers and 158 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. 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.

6

2017 PSE Integrated Resource Plan

Electric Analysis

This chapter presents the results of the electric analysis.

Contents

(continued next page)

1. ANALYSIS OVERVIEW

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

1. Analyze Resource Need

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

2. Determine Planning Assumptions and Identify Resource Alternatives

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

3. Deterministic Analysis of Scenarios and Sensitivities

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

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

4. Stochastic Risk Analysis

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

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

5. Analyze Results

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

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

6. Make Decisions

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

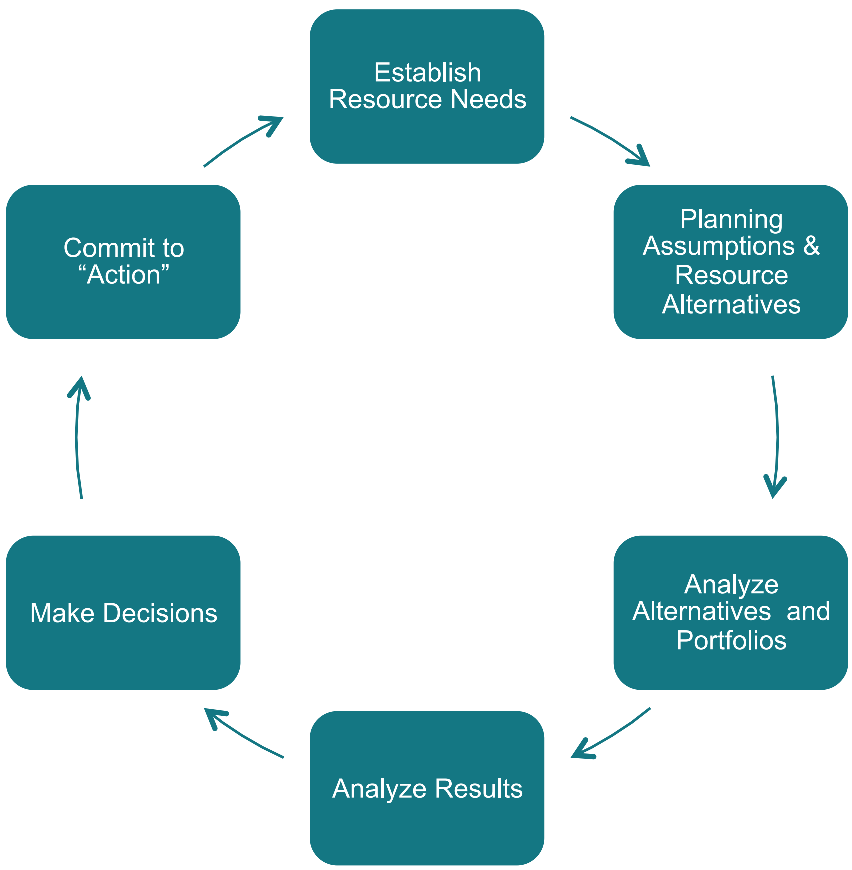
7. Commit to Action

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

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

Figure 6-1 illustrates this process.

Figure 6-1: 2017 IRP Process



2. RESOURCE NEED

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

Components of Physical (Peak) Need

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

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

Customer Demand

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

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

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

Planning Margin

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability (LOLP). The 5 percent LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.[2] Appendix N provides a detailed discussion of how PSE's Resource Adequacy Model is used to develop the planning margin.

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

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

STEP 1: USE RAM TO FIND CAPACITY NEED. This analysis looked at the likelihood that load will exceed resources on an hourly basis over the course of a full year. Included are uncertainties around temperature impacts on loads before conservation, hydro conditions, wind, and forced outage rates (both their likelihood and duration), and uncertainties in market reliance based on the Council's regional adequacy model, GENESYS. Because of PSE's large reliance on the market, it is important that PSE's resource adequacy analysis is consistent with the regional assessment of resource adequacy. Both GENESYS and RAM use a Monte Carlo simulation that consists of 6,160 draws that model different temperature conditions, hydro conditions and thermal forced outage rate assumptions. Each of the draws and study year are consistent for both models. This analysis resulted in the need for 503 MWs of additional resources for PSE to achieve a 5 percent LOLP in the study year October 2020 – September 2021.[3]

2 / See http://www.nwcouncil.org/library/2008/2008-07.htm
3 / The 503 MW need is before including additional cost-effective conservation. We need to establish resource need first, and then we determine how much of that need would cost effectively be met by conservation.

STEP 2: DETERMINE PLANNING MARGIN. Figure 6-2 shows the calculation of the planning margin to achieve the adequate level of reliability. Given that PSE has a winter peaking load, any capacity brought in to meet the planning margin in the winter is also available to meet capacity in other seasons. The 503 MW need in December 2020 was calculated with Colstrip Units 1 & 2 retired, consistent with the NPCC GENESYS assumptions. The 503 MW capacity need translates to a 13.5 percent planning margin, not including reserves.

Figure 6-2: Planning Margin Calculation

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

STEP 3: DETERMINE RESOURCE NEED WITH COLSTRIP 1 & 2. Since Colstrip Units 1 & 2 do not retire till mid-2022, we add its capacity back into the calculation (that is, subtract it from the 503 MW capacity need). This results in a capacity need in December 2020 of 123 MW. See Figure 6-3, below, for peak need calculation. This is the reverse of Figure 6-2, above. In Figure 6-2, we were trying to find the planning margin. Now, we know the planning margin is 13.5 percent, so we have reversed the calculation to find the peak need.

Figure 6-3: December Peak Need in 2020, with Colstrip 1 & 2

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

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

Figure 6-4: ELCC Estimates

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

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

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

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

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

Operating Reserves

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

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

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

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

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

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

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

Existing Resources

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

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

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

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

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

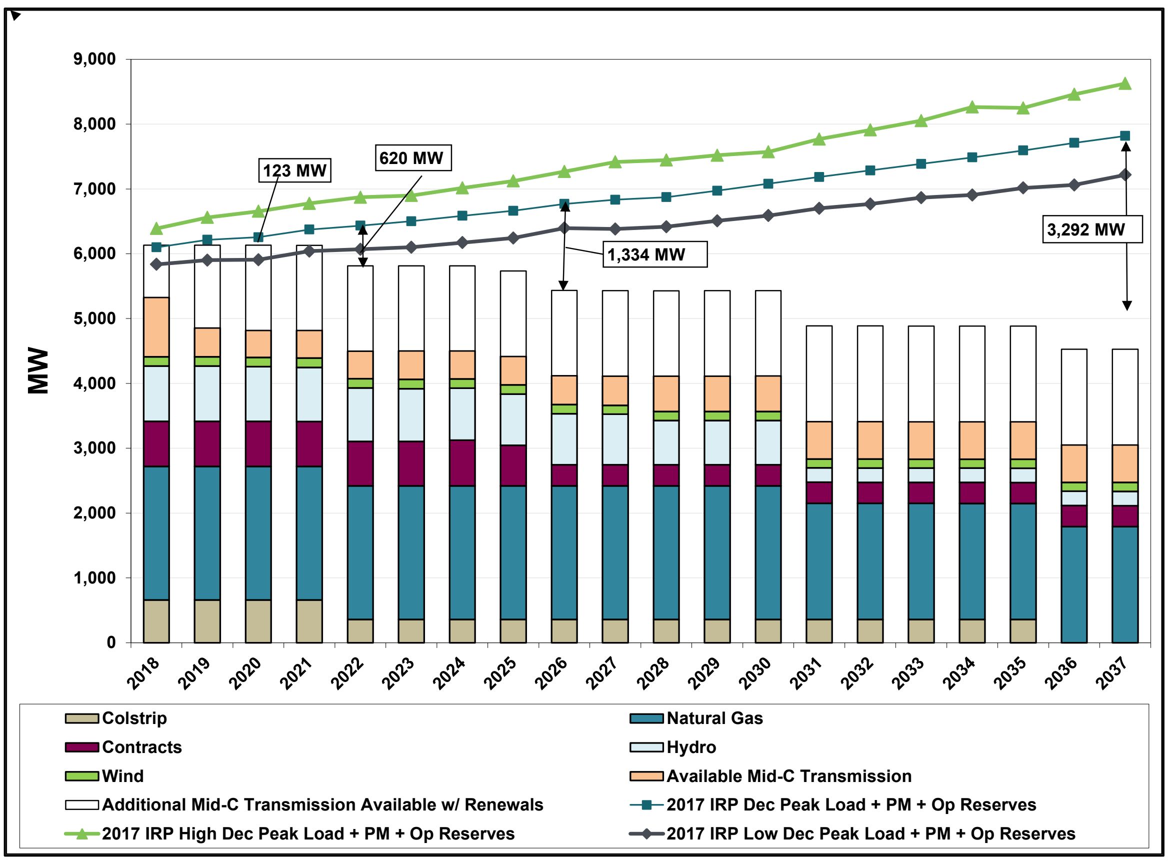
Figure 6-6: PSE Mid-C Transmission Capacity as of December 2016

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

Peak Capacity Need

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

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



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

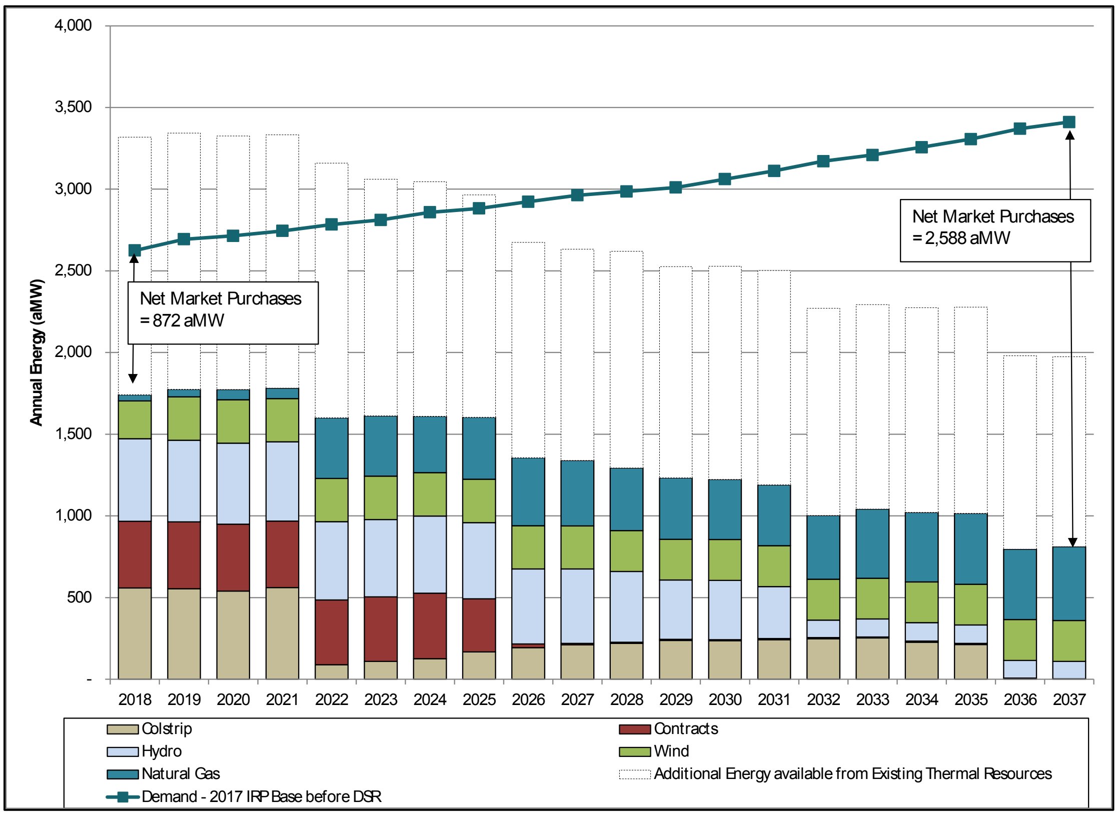
Energy Need

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

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

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

Figure 6-8: Annual Energy Position
Resource Economic Dispatch from Base Scenario



Renewable Need

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

Washington State RPS Targets

Renewable resources must comprise:

3 percent of supply-side resources by 2012

9 percent of supply-side resources by 2016

15 percent of supply-side resources by 2020

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

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

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

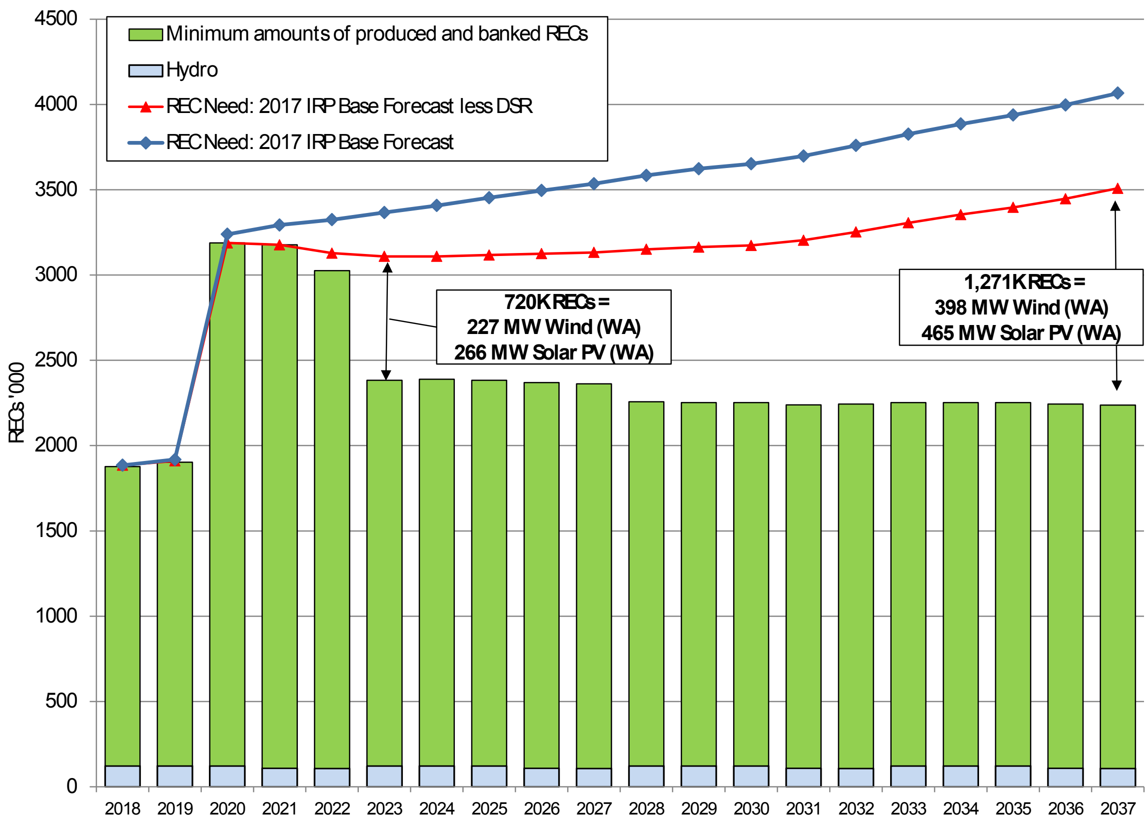
DEMAND-SIDE ACHIEVEMENTS AFFECT RENEWABLE AMOUNTS. Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, if MWh sales decrease, so does the amount of renewables we need. Achieving demand-side resources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

REC Banking Provision

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

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

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



3. ASSUMPTIONS AND ALTERNATIVES

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

Scenarios and Sensitivities

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

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

Figure 6-10: 2017 IRP Scenarios

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

Fig 6-11: 2017 IRP Portfolio Sensitivities

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

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

NOTES

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

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

Cost of Carbon Abatement Alternatives Analyzed

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

Figure 6-12: Carbon Abatement Alternatives Analyzed

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

Available Resource Alternatives

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

Supply-side Resources

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

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

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

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

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

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

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

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

Demand-side Resources

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

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

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

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

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

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

4. TYPES OF ANALYSIS

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

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

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

Deterministic Portfolio Optimization Analysis

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

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

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

The initial AURORA input price run produces:

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

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

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

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

Figure 6-13: Flexibility Benefit

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

The Portfolio Screening Model III (PSM III) is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. This model produces the least-cost mix of resources using a linear programming, dual-simplex method that minimizes the present value of portfolio costs subject to planning margin and renewable portfolio standard constraints.

The solver used for the linear programming optimization is Frontline System's Risk Solver Platform. This is an excel add-in that works with PSM III. Incremental cost includes: 1) the variable fuel cost and emissions for PSE's existing fleet, 2) the variable cost of fuel emissions and operations and maintenance for new resources, 3) the fixed depreciation and capital cost of investments in new resources, 4) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and 5) the market purchases or sales in hours when resource-dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM III are:

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

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

Stochastic Risk Analysis

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

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

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

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

5. KEY FINDINGS

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

Scenarios

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

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

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

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

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

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

Sensitivities

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

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

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

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

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

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

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

Demand-side Resources

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

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

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

Wind Resources

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

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

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

Carbon Abatement Cost Curve

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

6. SCENARIO ANALYSIS RESULTS

Portfolio Builds

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

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

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

Summary of Deterministic Optimization Analysis

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

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

Scenarios 1-9

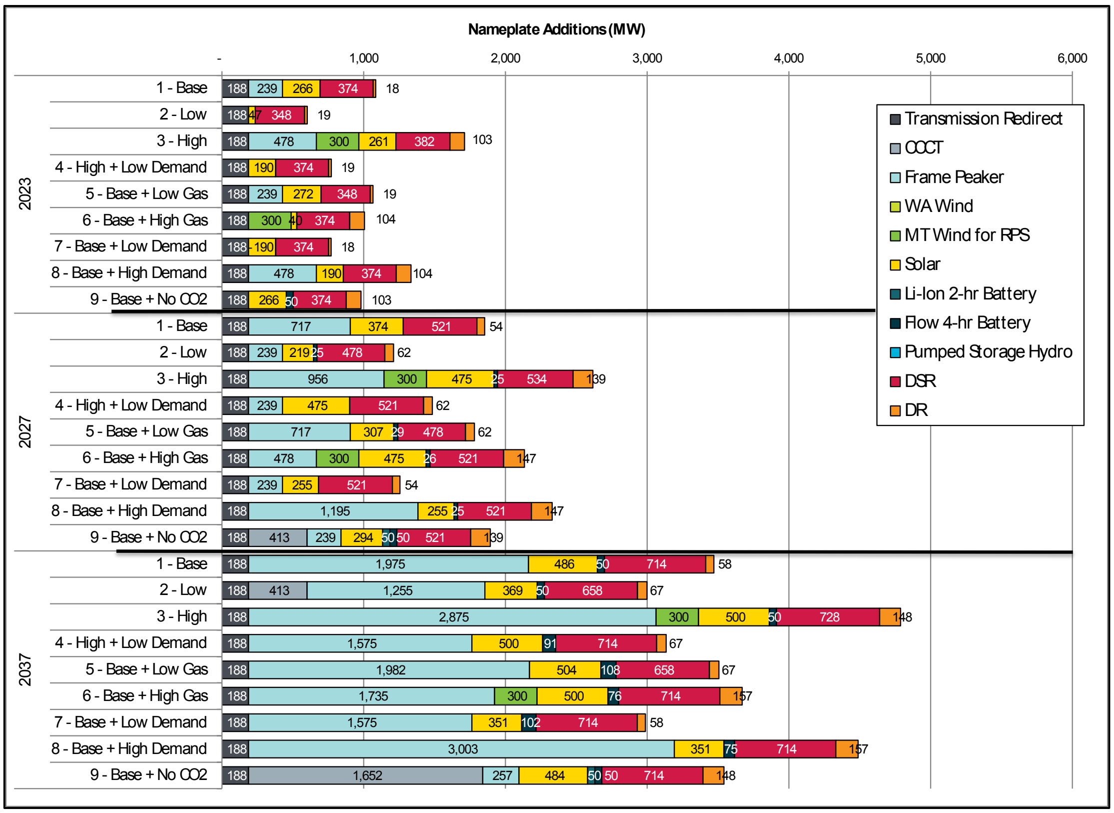
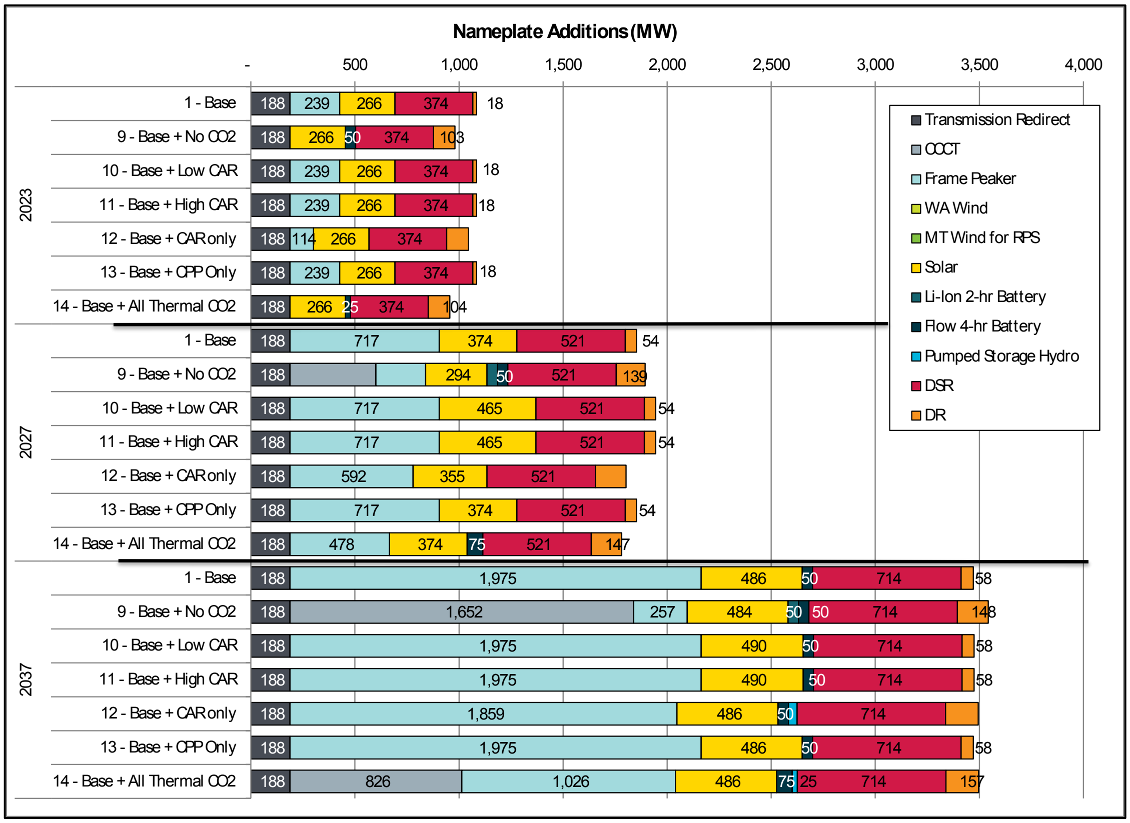


Figure 6-15 (continued)

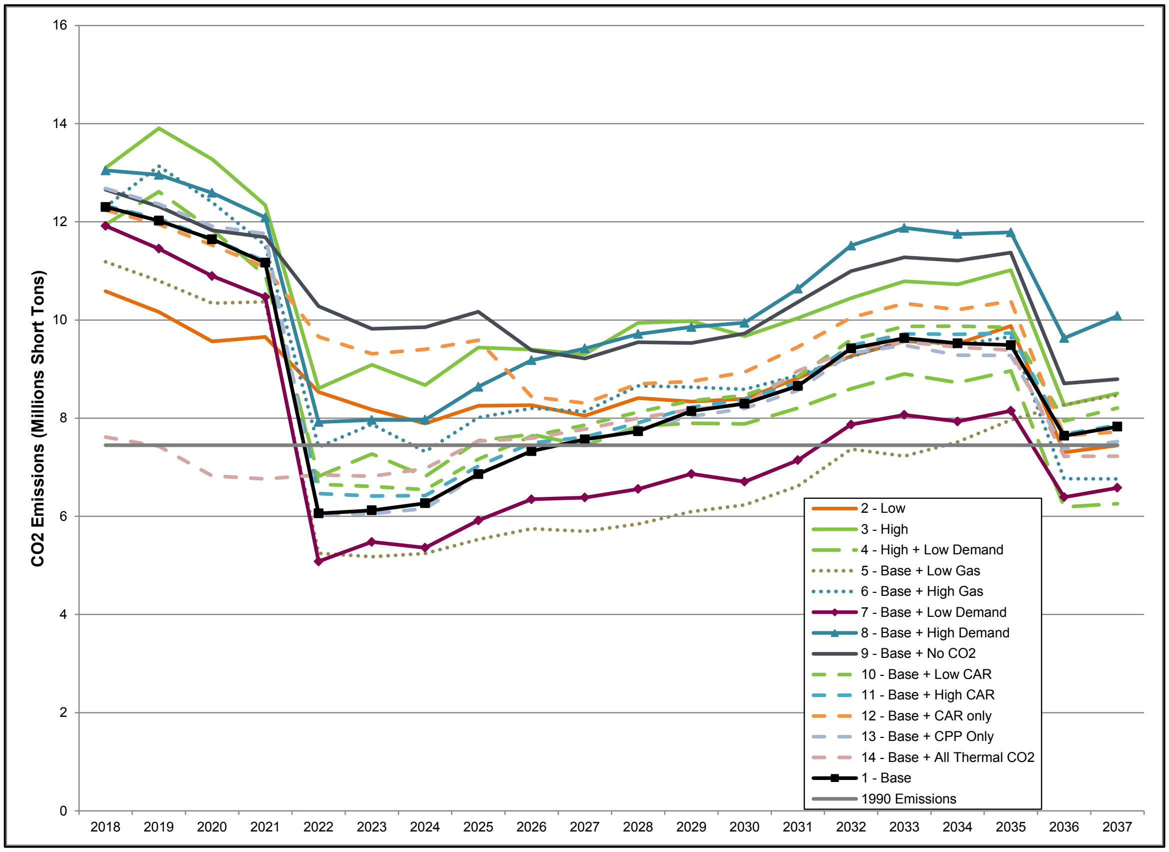
Scenarios 9-14



Portfolio Emissions

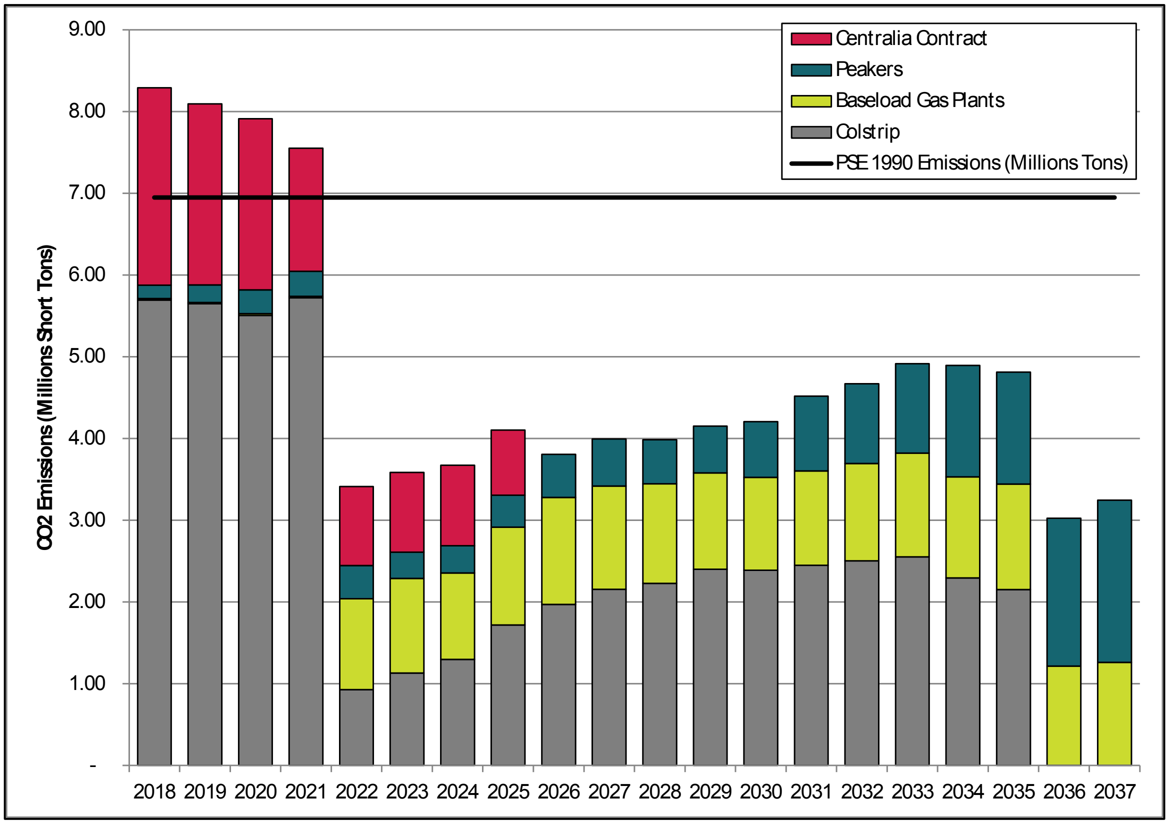
In this section we present results of our “portfolio emissions” analysis. An important detail is that this chart applies an average annual carbon intensity to the market purchases that make up nearly a third of PSE’s portfolio. PSE’s approach to accounting for market purchases is to calculate a WECC-wide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

Figure 6-16: CO_2 Emissions by Portfolio



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

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



Cost of Capacity

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

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

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

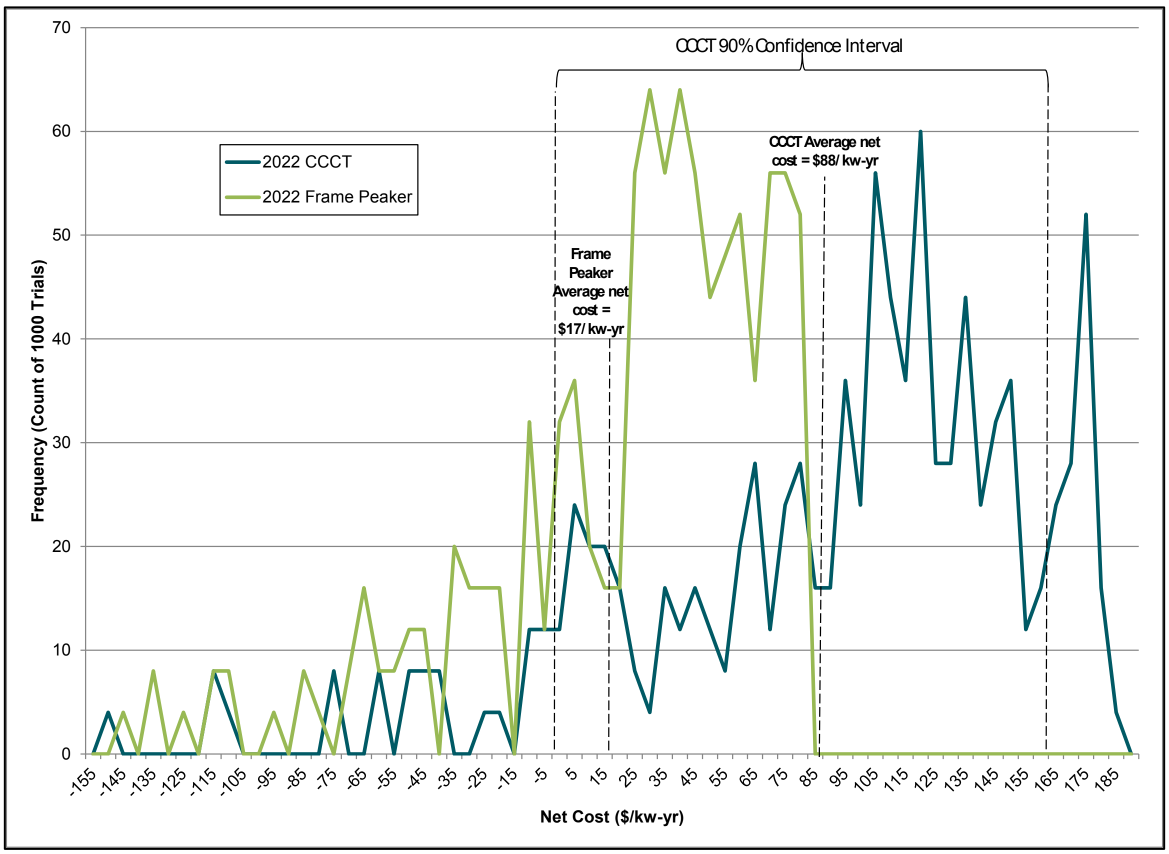
Figure 6-18 compares the cost of peakers and baseload gas plants across scenarios. In the scenarios where the baseload gas plants look more cost effective, the dispatch of the baseload plants is high, so the plant produces a lot of excess power to sell into the market; this creates revenue that lowers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

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

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

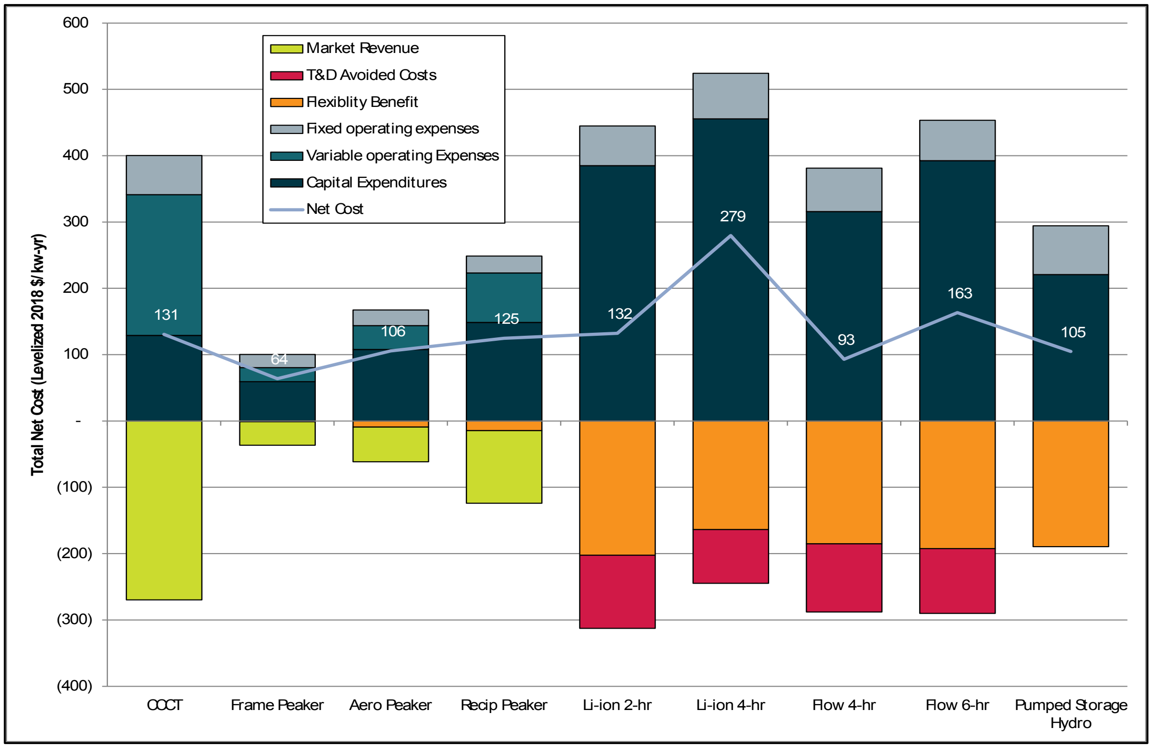
Net cost is not specifically used as part of the cost minimization function; however, showing net cost may provide useful insights. Figure 6-19 illustrates how the net cost of a baseload gas plant is significantly affected by the margin it generates. A 250-simulation Monte Carlo analysis for a 2022-vintage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

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



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

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



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

Backup Fuel Capacity

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

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

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

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

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

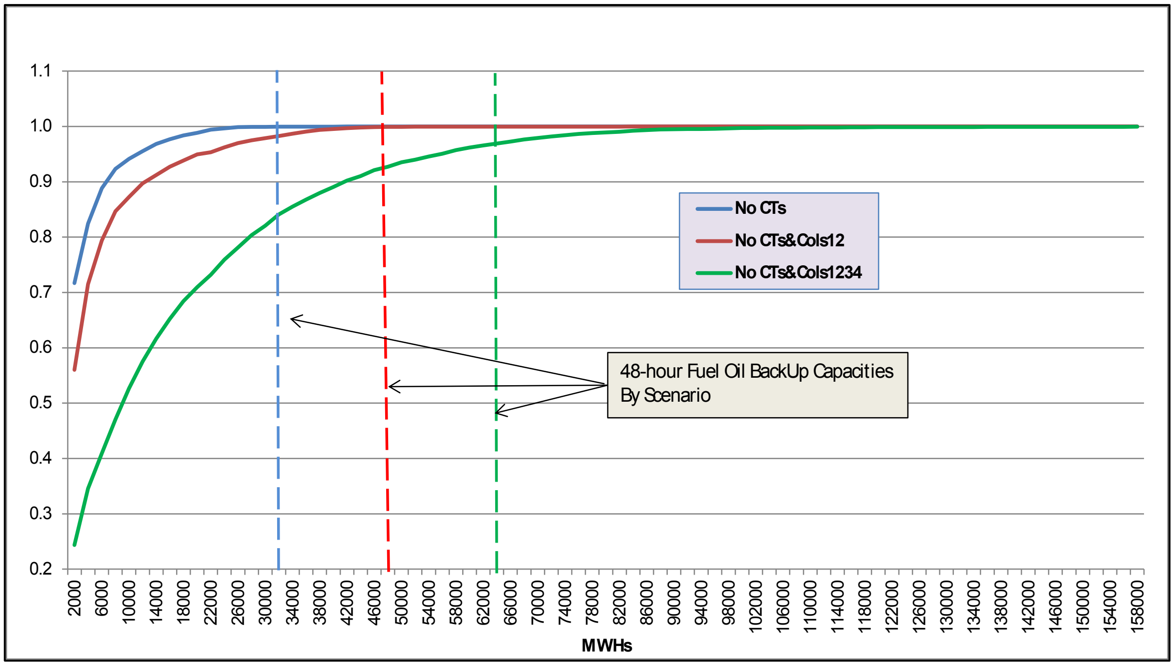
To determine if the results of the analysis are invariant to the scale of the capacity that is not available to meet resource adequacy, three scenarios were examined.

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

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

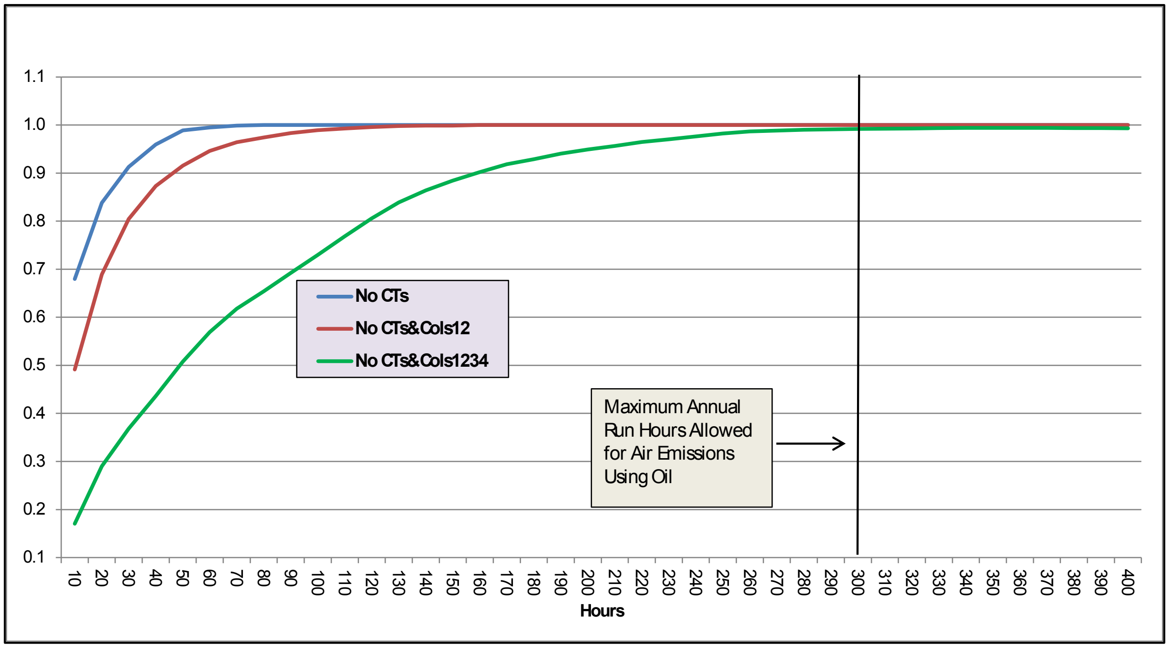
The chart below shows the cumulative distribution of MWhs resulting from the incremental outage events for each of the three scenarios. The higher the level of capacity that is unable to run due to the lack of gas supply, the greater the amount of deficit MWhs. This is shown by the rightward shift in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

Figure 6-21: Cumulative Distribution of Incremental Deficit for Bad Simulations in MWh/yr



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

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



Renewable Builds

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

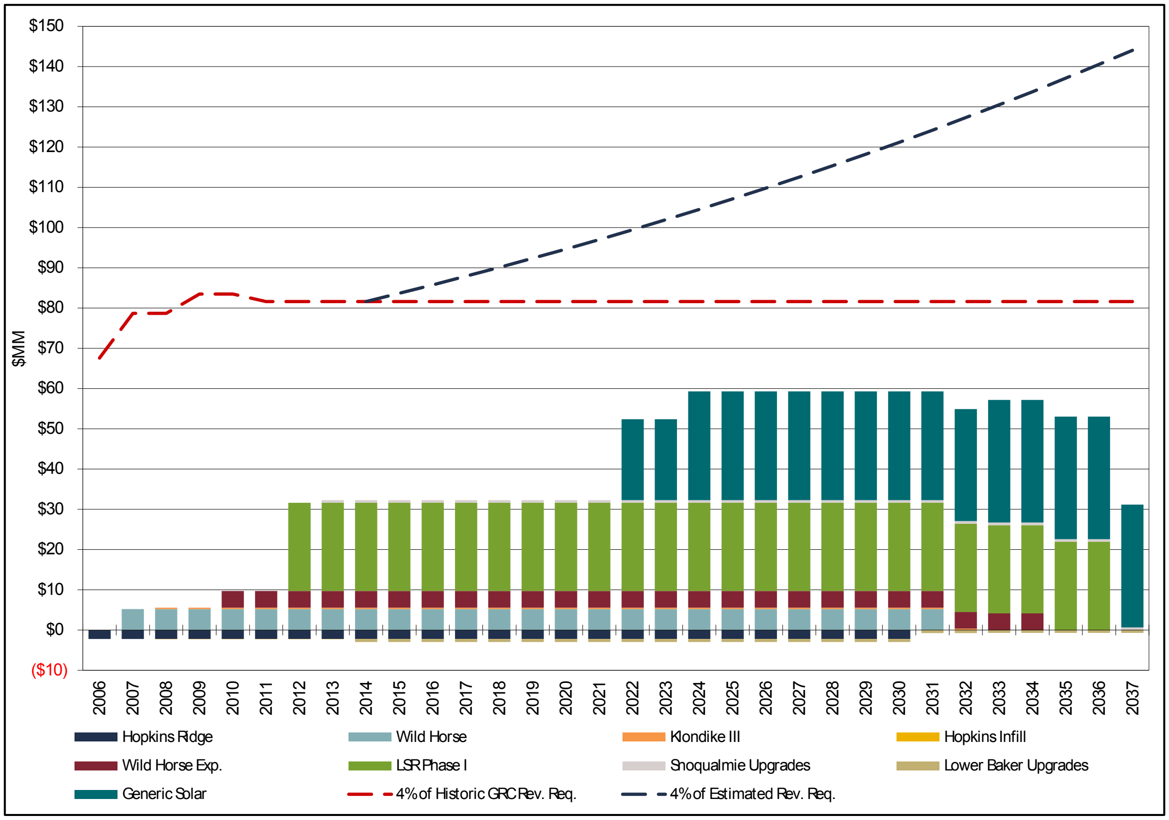
RPS Incremental Cost Cap Analysis

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

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure 6-23 presents results of this analysis for existing resources and projected resources. This demonstrates that PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

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

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

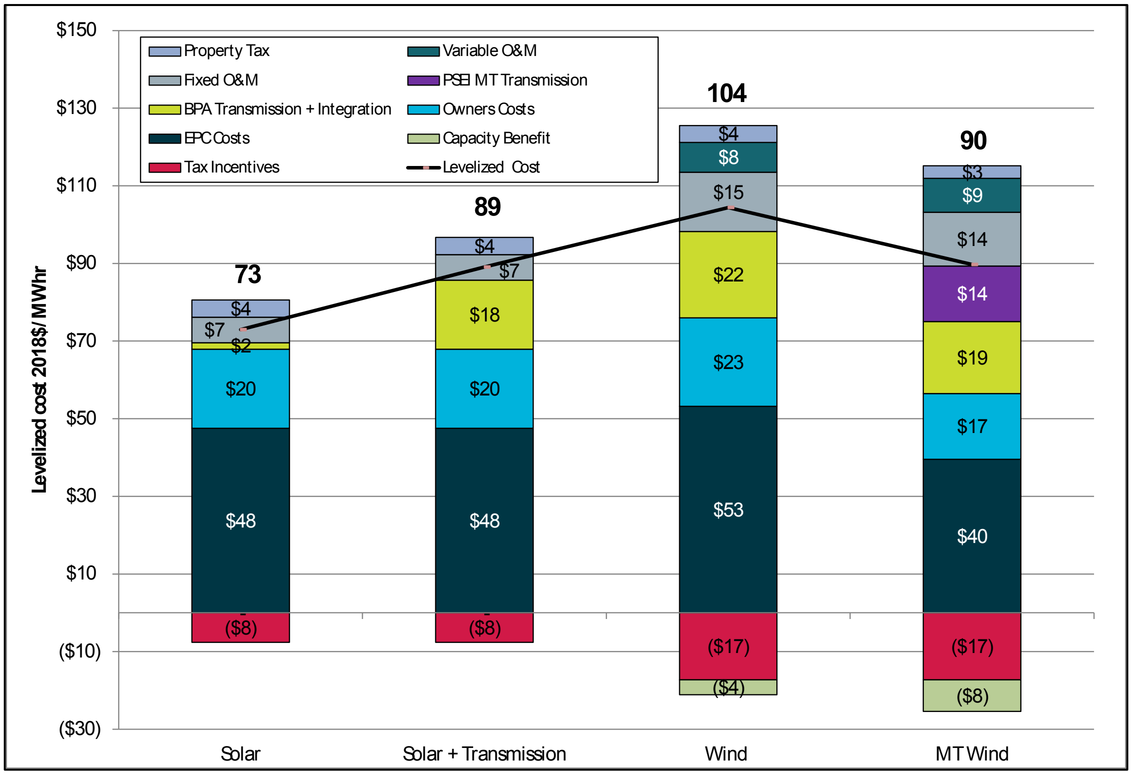


Renewable Resource Costs

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

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

Figure 6-24: Wind and Solar Cost Components



7. SENSITIVITY ANALYSIS RESULTS

A. Colstrip

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

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

Sensitivity 1: Retire Units 1 & 2 in 2018.

Sensitivity 2: Retire Units 3 & 4 in 2025.

Sensitivity 3: Retire Units 3 & 4 in 2030.

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

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

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

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

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

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

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

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

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

B. Thermal Retirement

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

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

Sensitivity 1: Baseload gas plants retire in 2031.

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

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

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

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

C. No New Thermal Resources

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

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

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

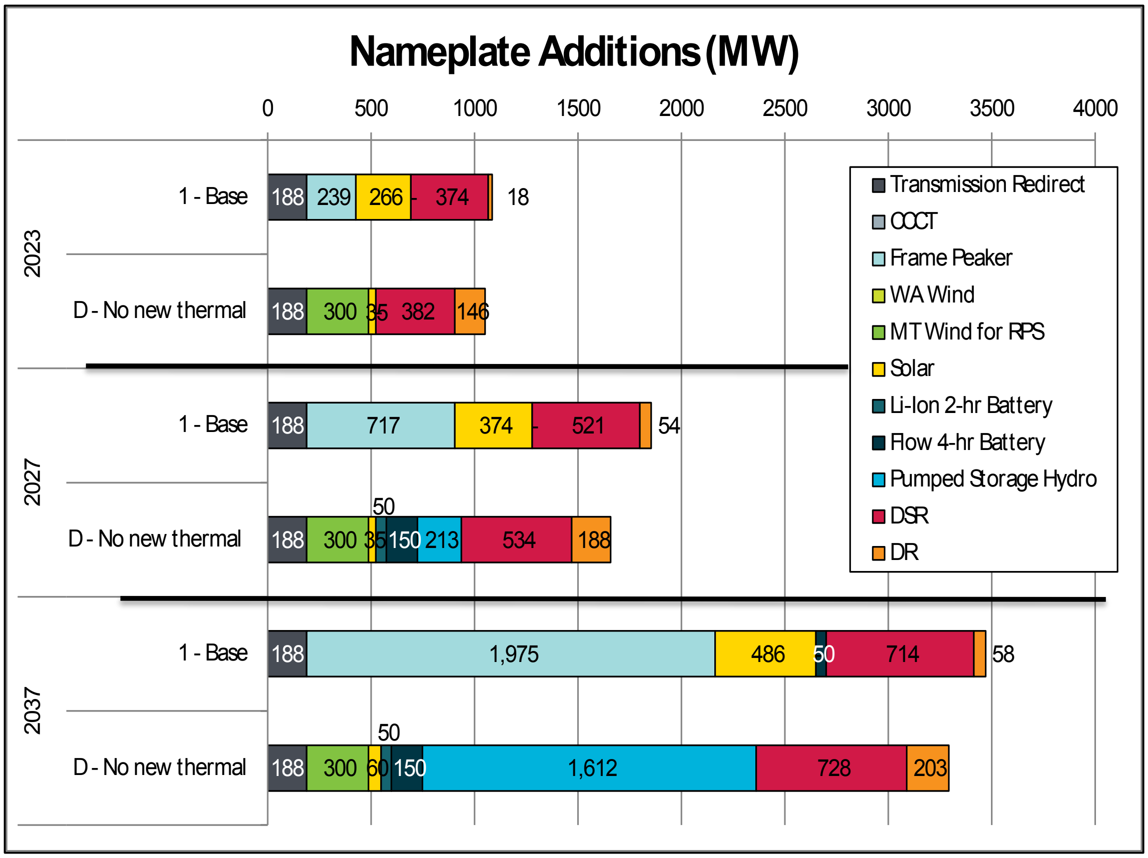
KEY FINDINGS. Adding no new thermal resources to the portfolio in the latter part of the planning horizon would increase both cost and risk, given current forecasts for resource costs, although those costs may change. To fill the gap, Montana wind and over 1,600 MW of pumped hydro storage would be needed.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

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

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

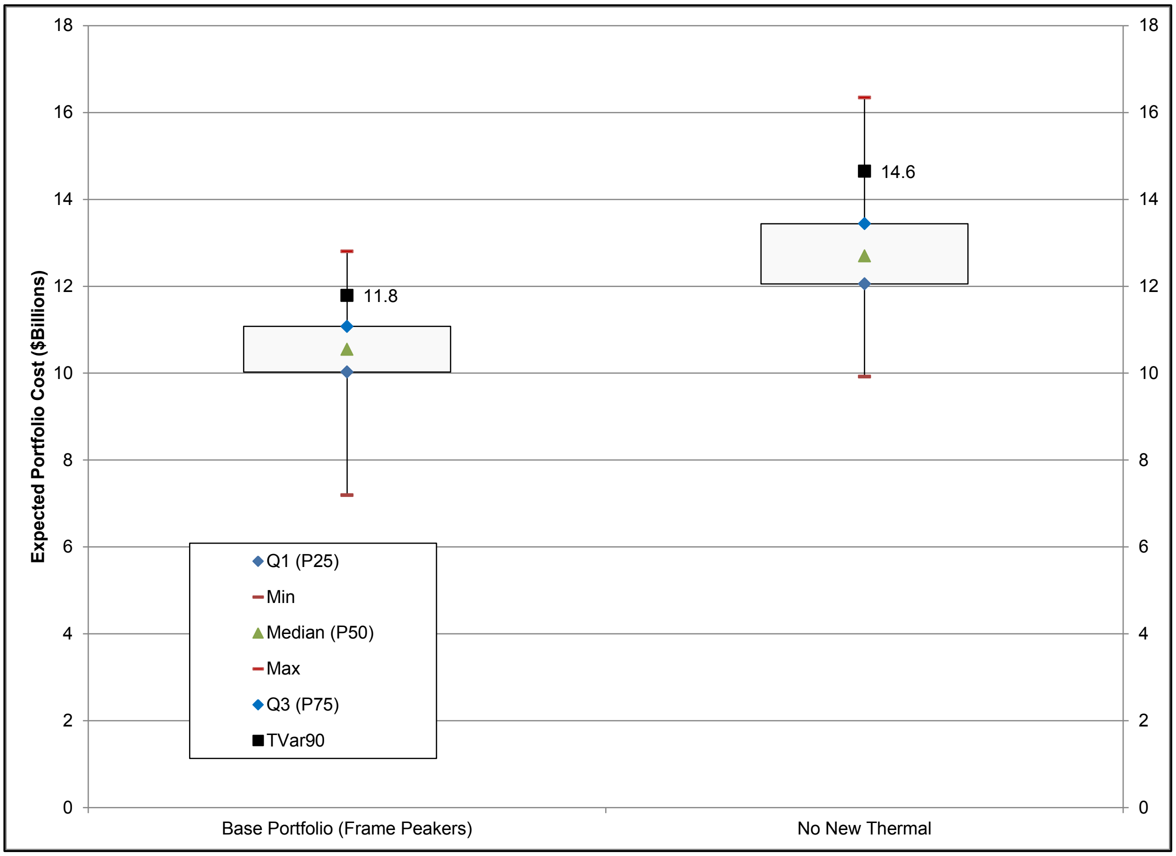
Portfolio Cost ($Millions)	NPV
1 – Base	$11,981
D – No New Thermal Resources	$13,343
Difference in Cost	**$1,362**

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



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

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



D. Stakeholder-requested Alternative Resource Costs

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

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

Sensitivity 1: Lower cost for recip peakers.

Sensitivity 2: Higher thermal capital costs.

Sensitivity 3: Lower wind and solar development costs.

Sensitivity 4: Apply more aggressive solar cost curve.

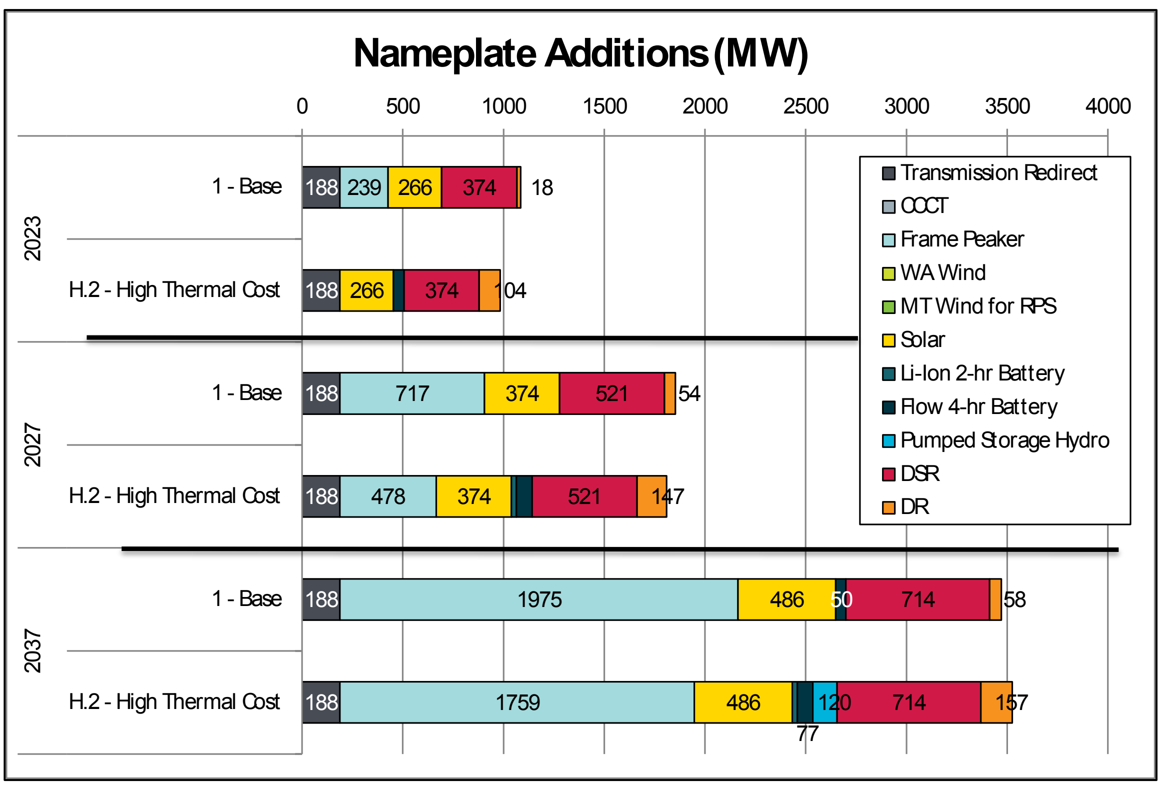
SENSITIVITY 1: LOWER COST FOR RECIP PEAKERS. This sensitivity tested a lower capital cost of recip peakers of $1,257/kW for a dual fuel unit with oil backup. This change did not affect the least-cost mix of resources. The total capital cost of the recip peakers would have to be reduced by more than 15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

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

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

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

Figure 6-30: Higher Thermal Cost Portfolio Builds



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

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

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

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

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

E. Energy Storage

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

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

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

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

Batteries

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

Pumped Hydro Storage

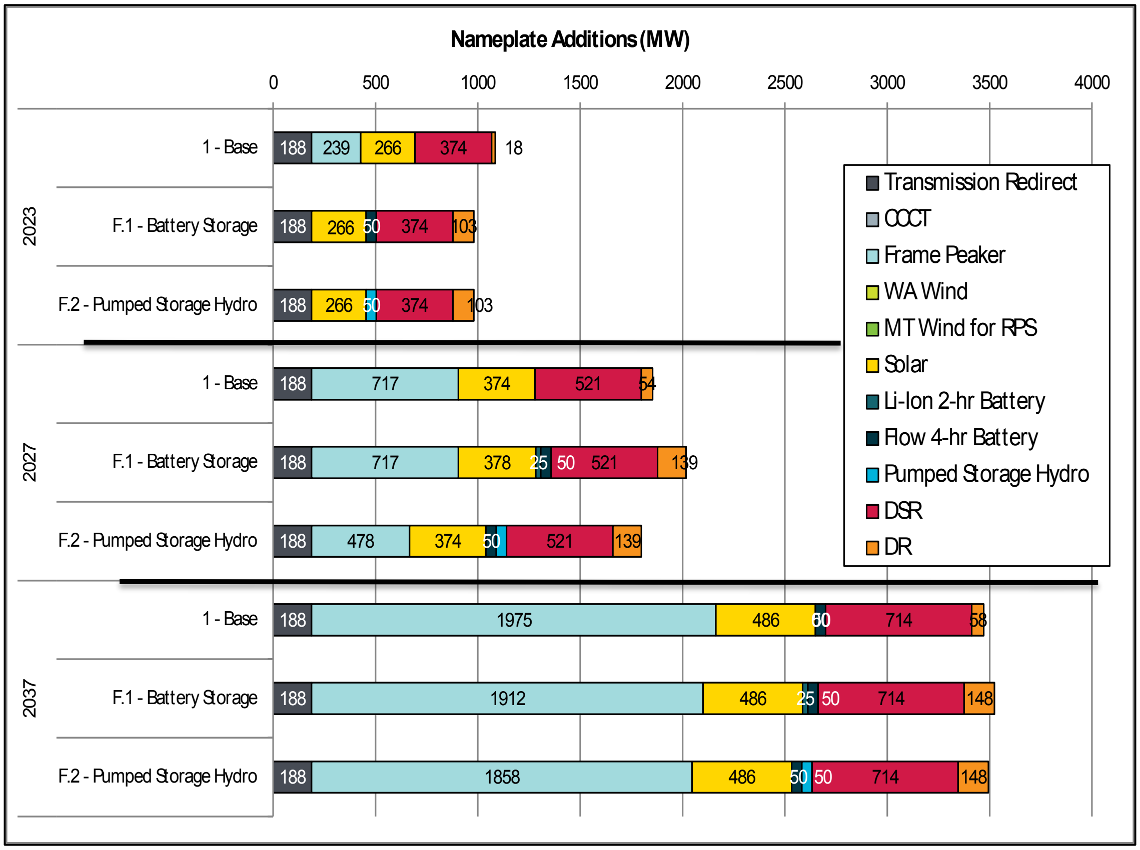
Pumped hydro is a proven storage technology that can also provide flexibility benefits. However, the facilities are expensive and may have controversial environmental impacts. Additionally, depending on where pumped hydro is located, transmission may be a challenge. Pumped hydro resources also may have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

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

Figure 6-31: Battery and Pumped Storage Portfolio Cost

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

Figure 6-32: Portfolio Additions, Energy Storage Sensitivity



F. Renewable Resources + Energy Storage

Does bundling renewable resources with energy storage change resource decisions?

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

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

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

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

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

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

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

G. Electric Vehicle Load

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

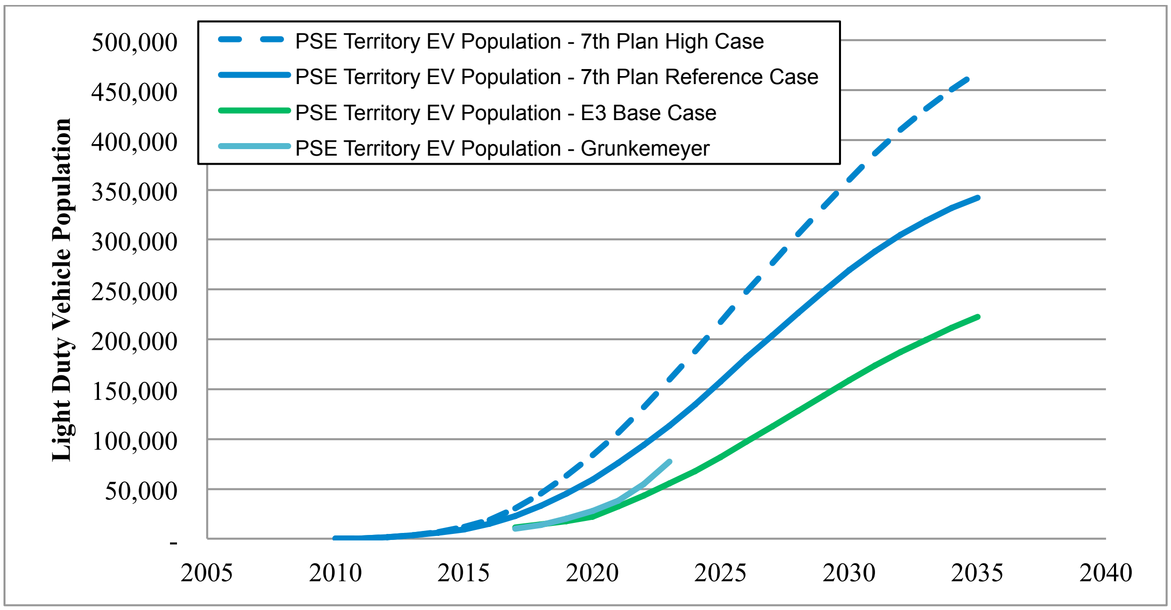
Baseline: IRP Base Demand Forecast.

Sensitivity: Add forecasted electric vehicle load.

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

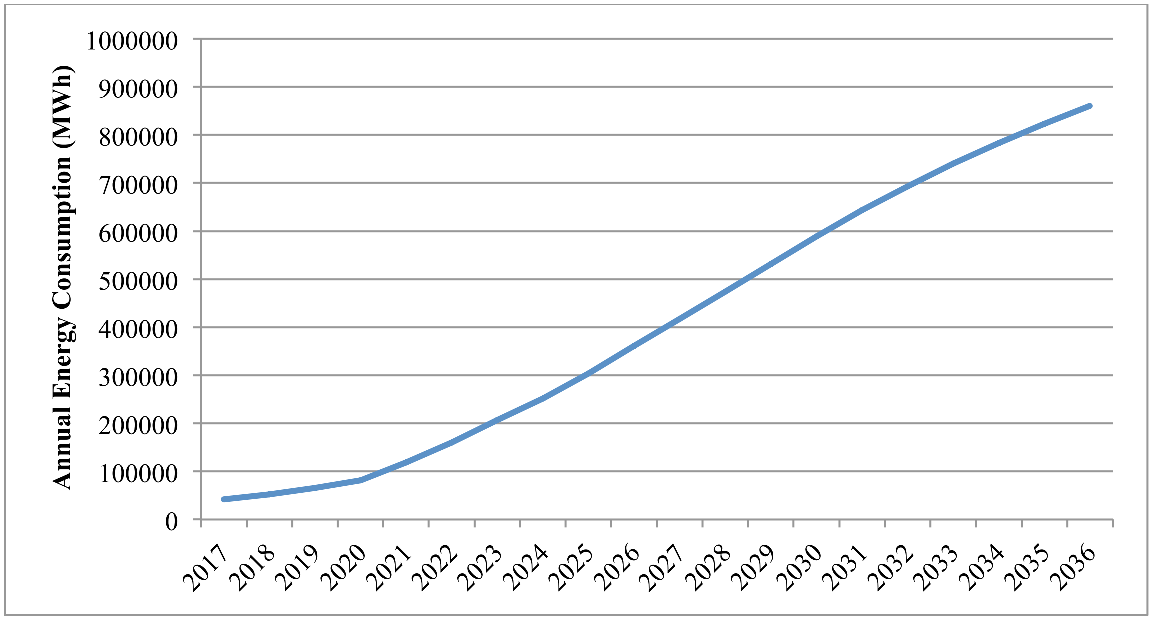
ASSUMPTIONS. This sensitivity models the impact of anticipated electric vehicle growth on resource needs. Currently, there are approximately 13,000 electric vehicles registered in PSE's electric service territory. The energy used in the sensitivity is built up from a forecast of the number of vehicles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

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



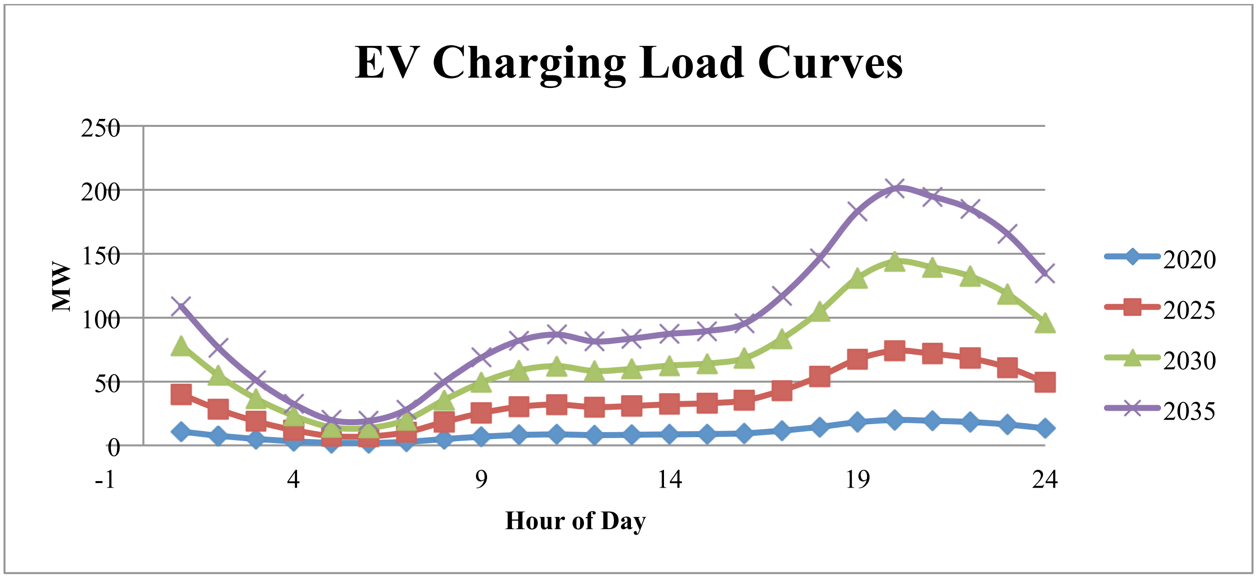
This vehicle forecast is translated to energy delivered using data on vehicle charging from the EV Project model of how electric vehicles are charged and how often that includes residential charging, workplace charging, public charging and fast public charging.

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



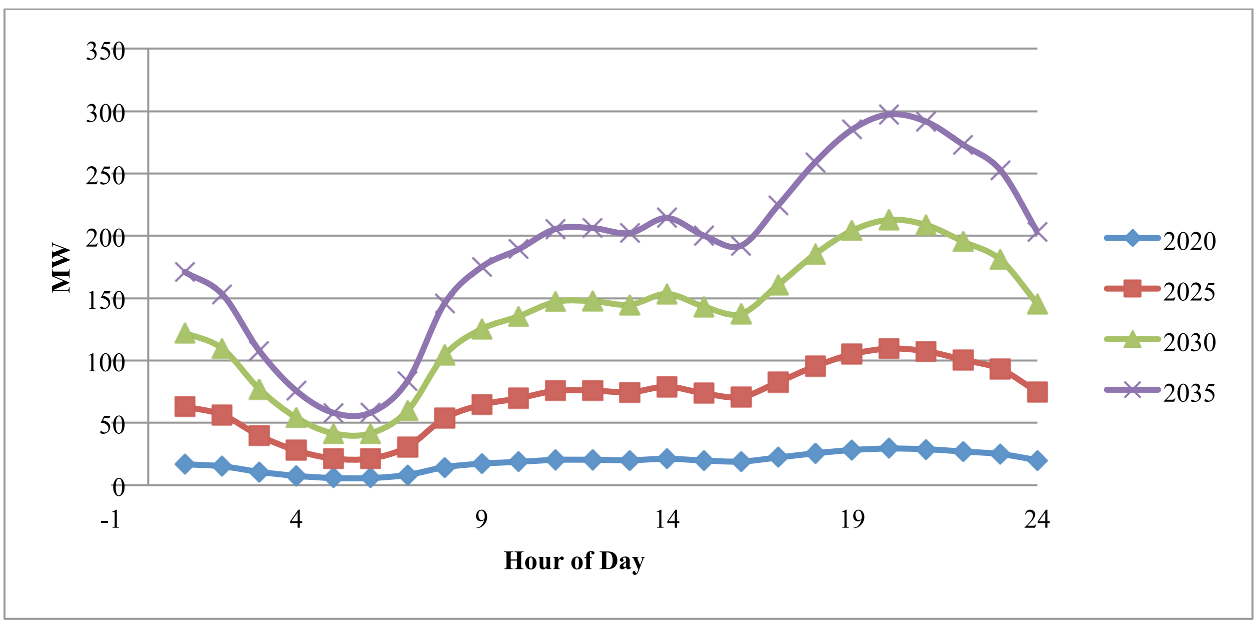
To develop the average load shape of the energy delivered, data from the EV Project and other sources were used to develop a time-based model of charging behavior that includes residential charging, workplace charging, public charging and fast public charging. The hourly profile for each of these types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

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



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

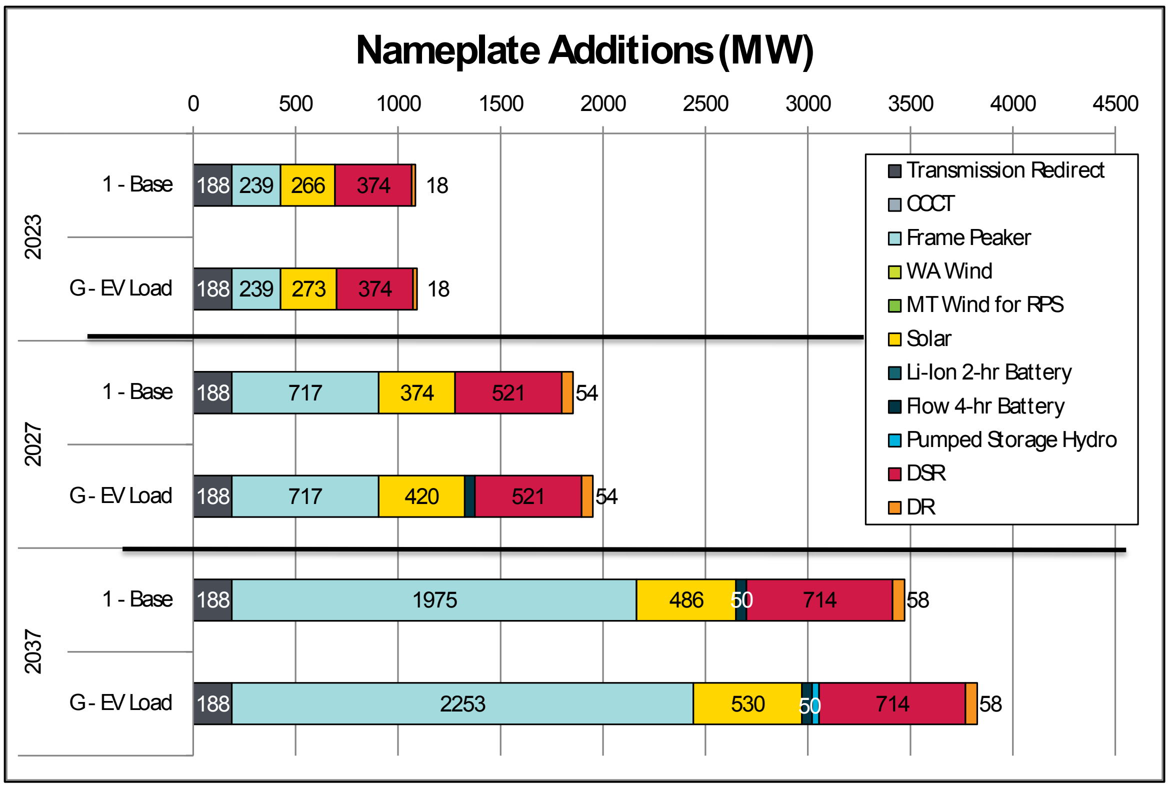
Figure 6-37: EV Charging Load Curves (Peak)



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

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

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



I. Demand-side Resources (DSR)

How much does DSR reduce cost, risk and emissions?

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

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

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

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

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

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

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

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

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

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

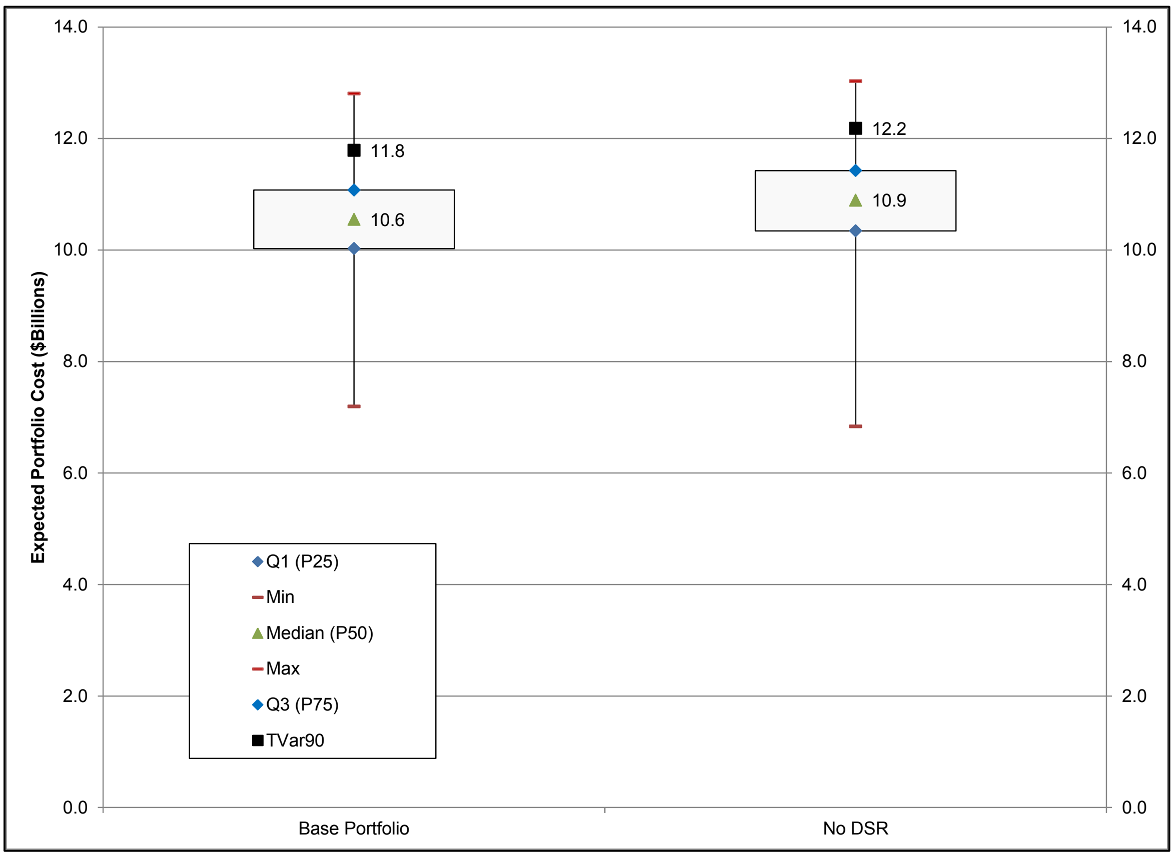


Figure 6-41 shows that DSR reduces power cost risk relative to no DSR. The TailVar90 of variable costs for the No DSR portfolio would be a little over $297 million higher than the Base Scenario optimal portfolio with DSR. It also illustrates that the No DSR portfolio revenue requirement is $555 billion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

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

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

J. Extended DSR Potential

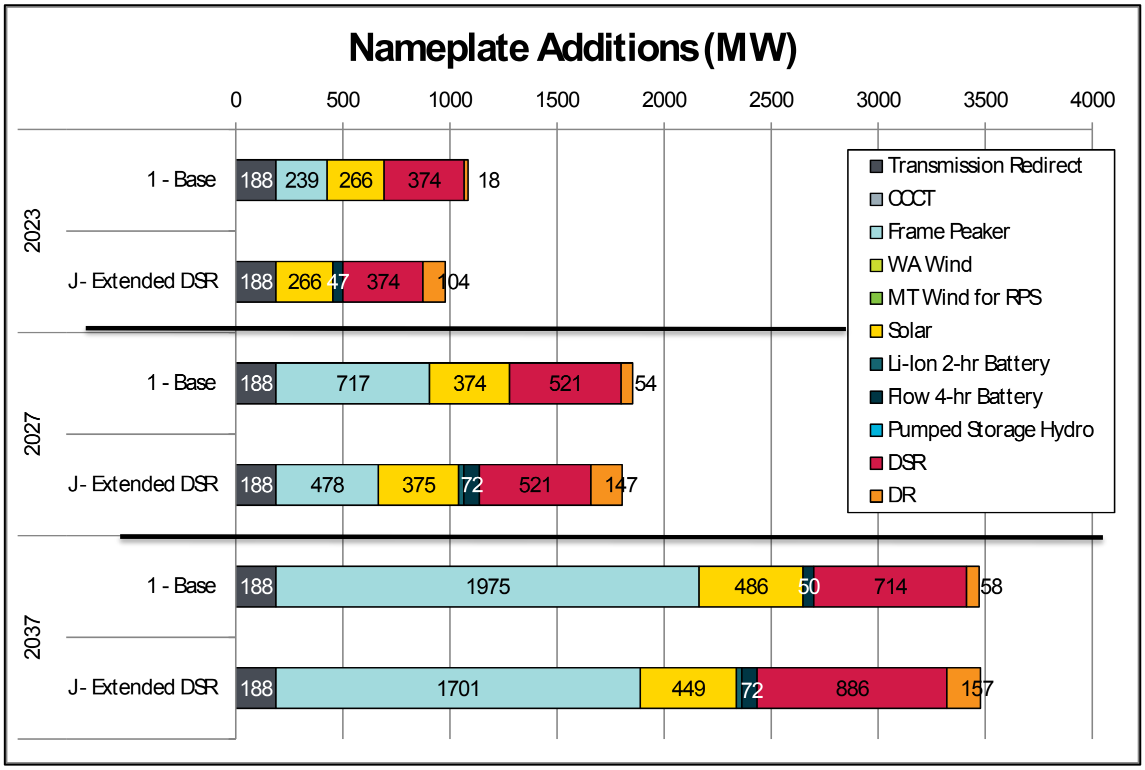
What if future DSR measures extend conservation periods through the second decade of the study period?

> **Baseline: All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.**
> **Sensitivity: Assume future DSR measures will extend conservation benefits through the second 10 years of the study period.**

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

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

Figure 6-42: Nameplate Additions, Extended DSR Sensitivity



K. Alternate Residential Conservation Discount Rate

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

Baseline: Assume the base discount rate.

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

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

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

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

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

Figure 6-43: DSR Potential

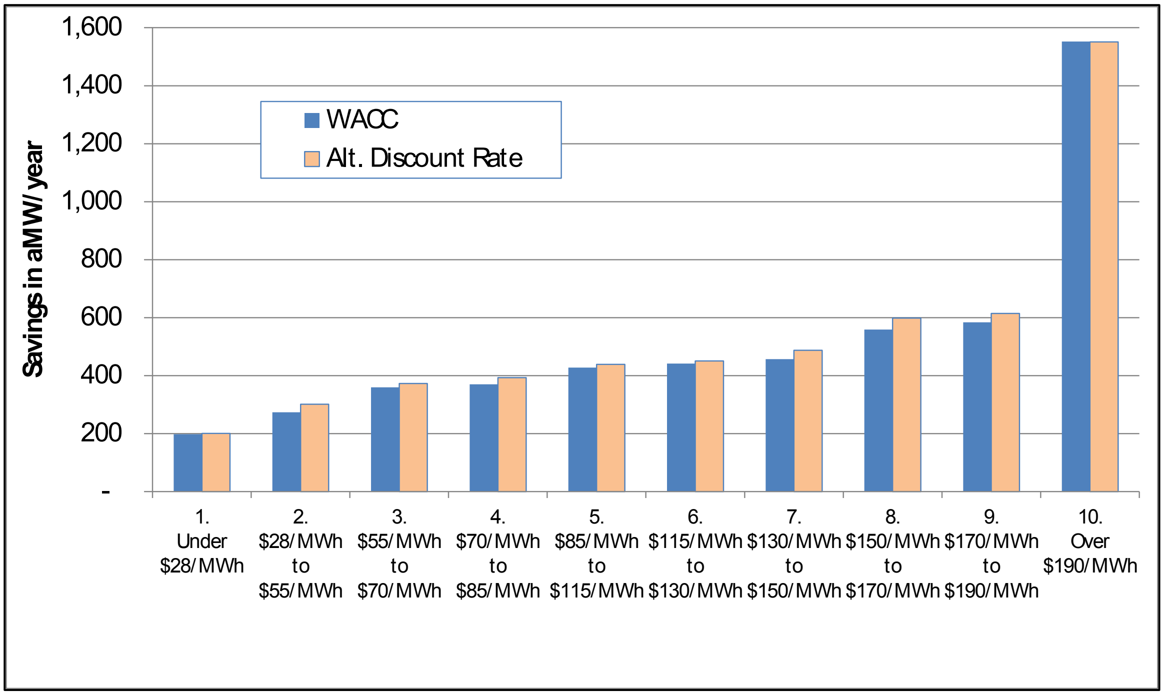
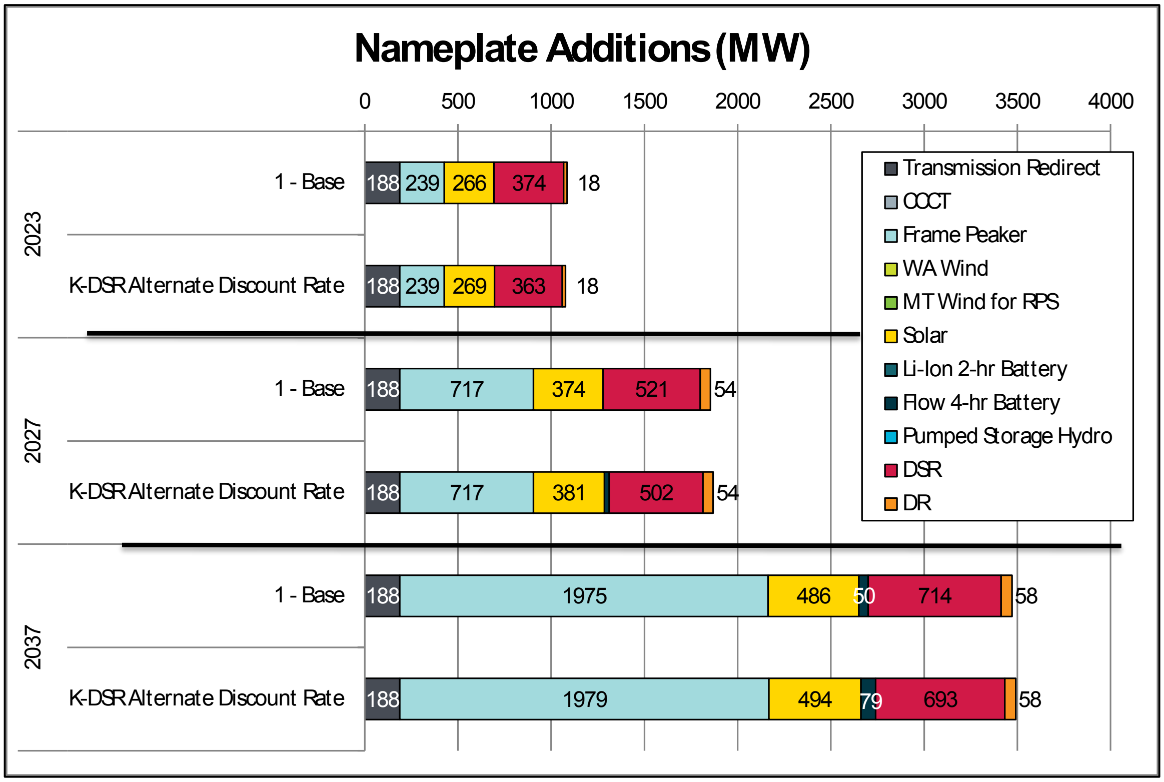


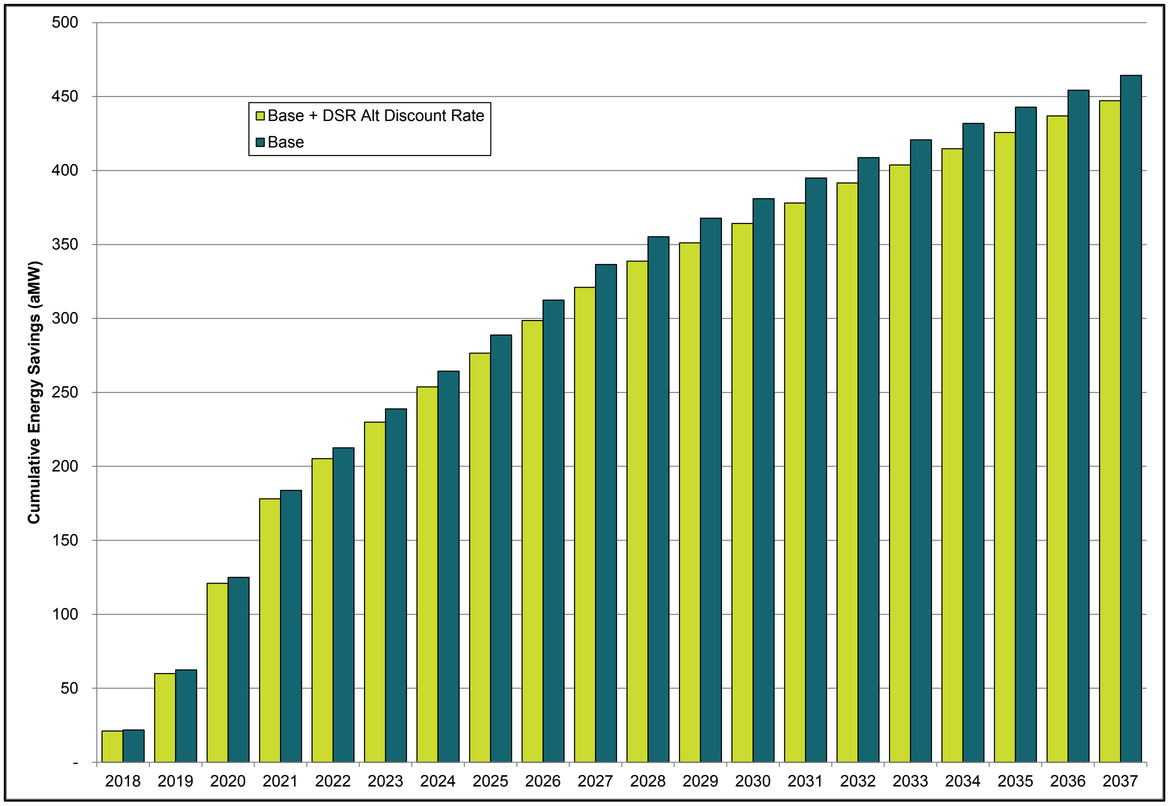
Figure 6-44 below compares the nameplate additions of resources for both Base Scenario portfolio DSR discount rate and the alternate discount rate. The Base Scenario portfolio has 772 MW of DSR, and the alternate discount rate portfolio has 693 MW of DSR.

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



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

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



L. RPS-eligible Montana Wind

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

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

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

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

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

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

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

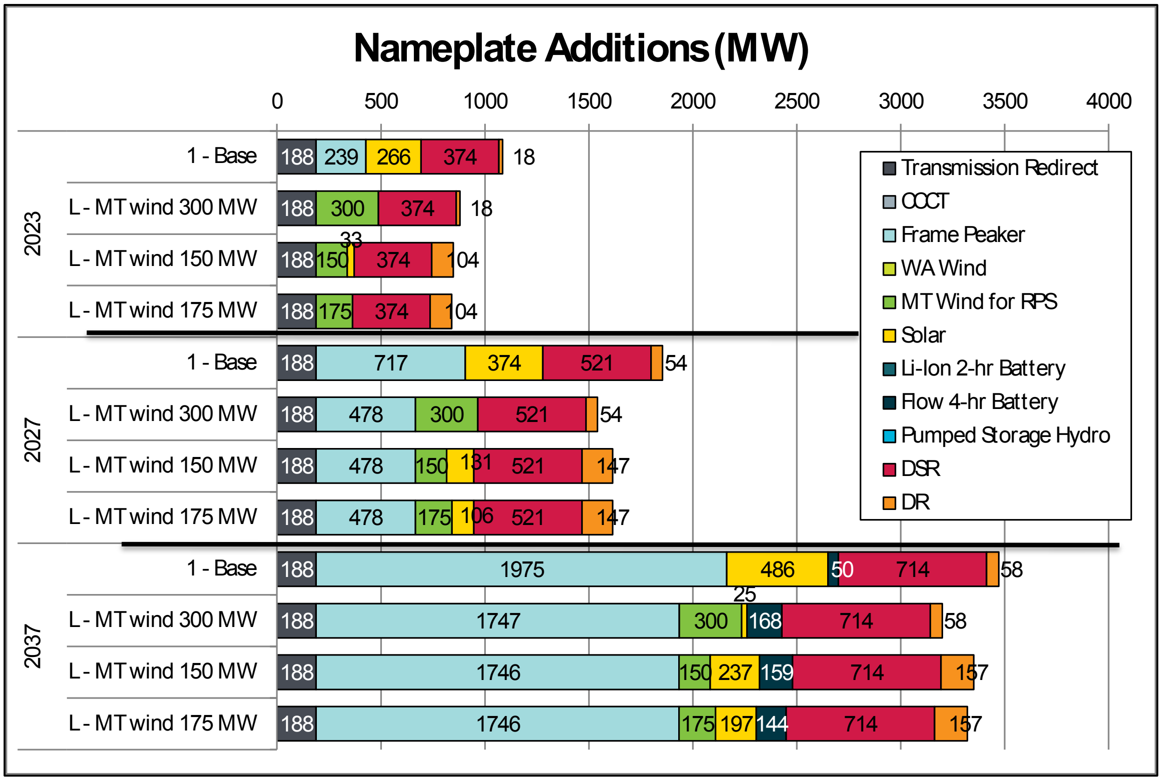
SUMMARY. Montana wind has the benefit of higher capacity factors than Washington wind (46 percent versus 30 percent), but it also requires added transmission costs to move the power to PSE's system. In addition, whether Montana wind qualifies as a qualifying renewable resource under RCW 19.285 depends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

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

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

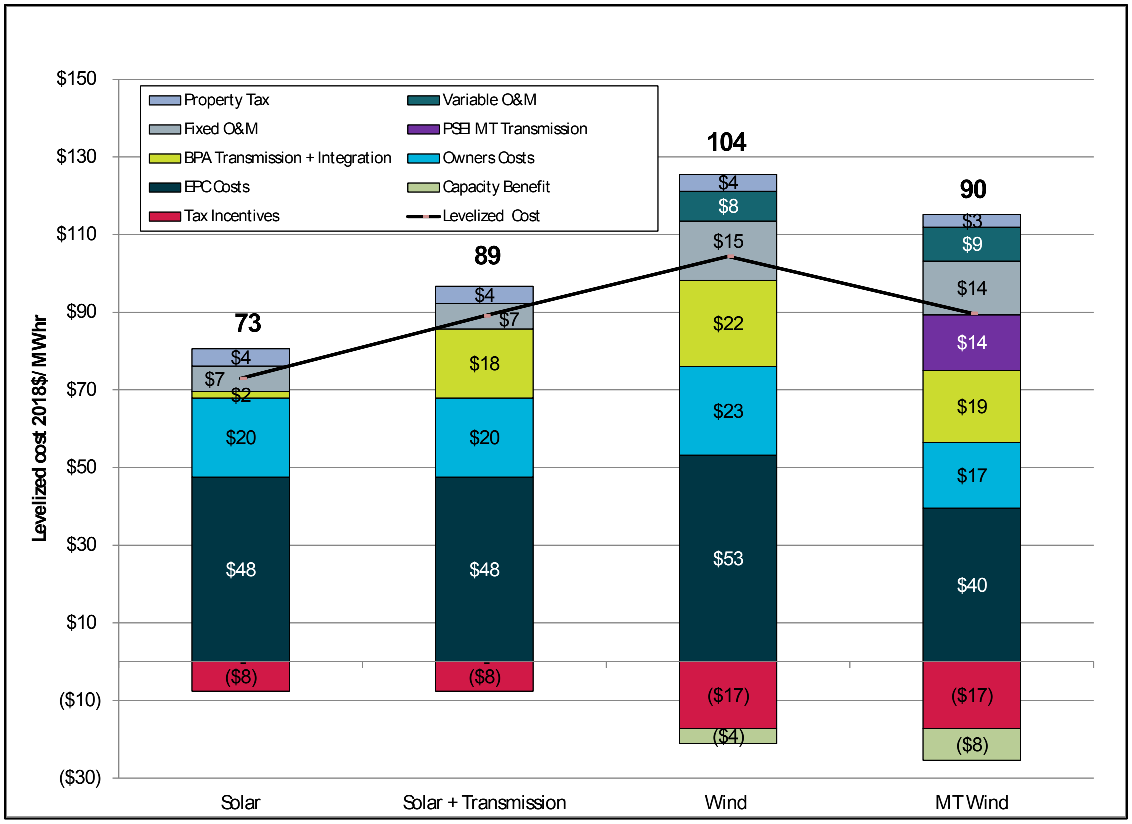
Figure 6-46 shows the total nameplate additions for the Base Scenario portfolio and a portfolio with Montana wind.

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



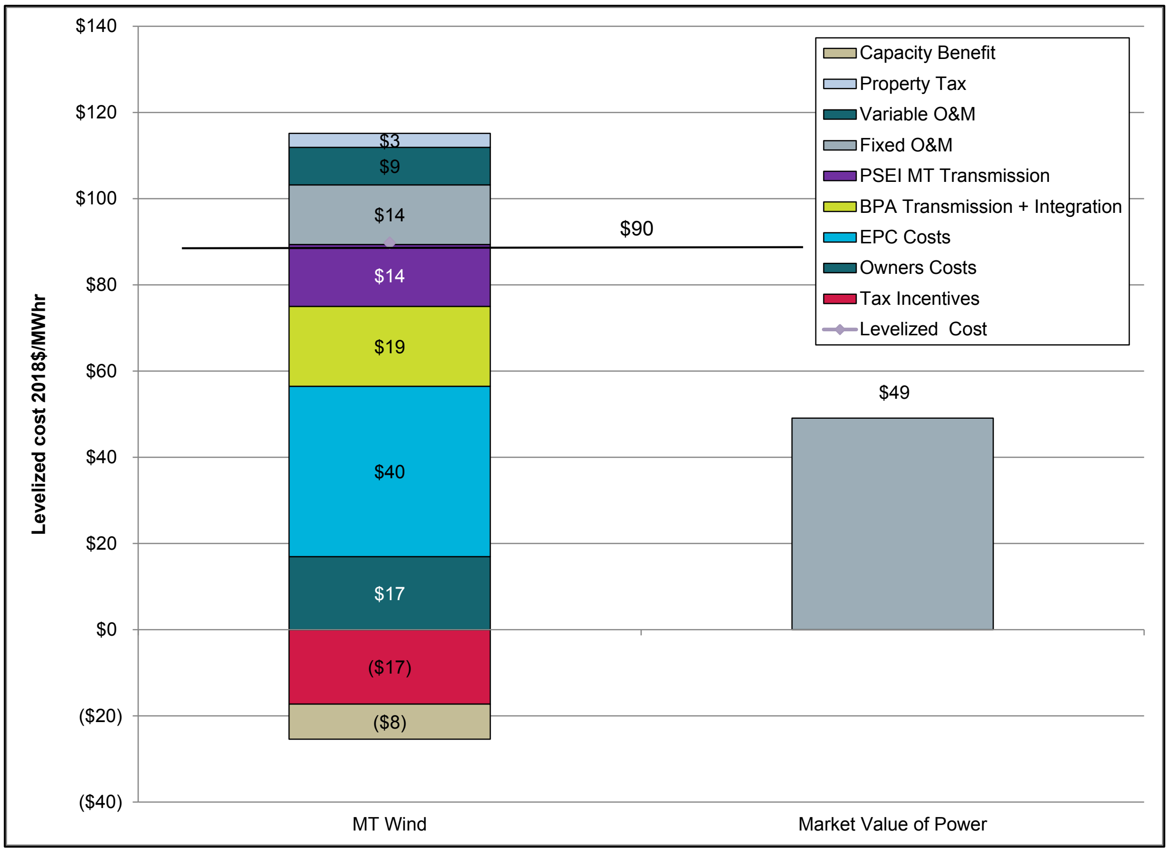
To be cost-competitive with solar resources at this time, the total cost of Montana wind would have to decrease by 16 percent. Figure 6-47 shows that Montana wind has a total levelized cost of $90/MWh, including the capacity value.

Figure 6-47: Wind and Solar Cost Components



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

Figure 6-48: Wind and Solar Cost Components



M. Offshore Wind Tipping Point Analysis

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

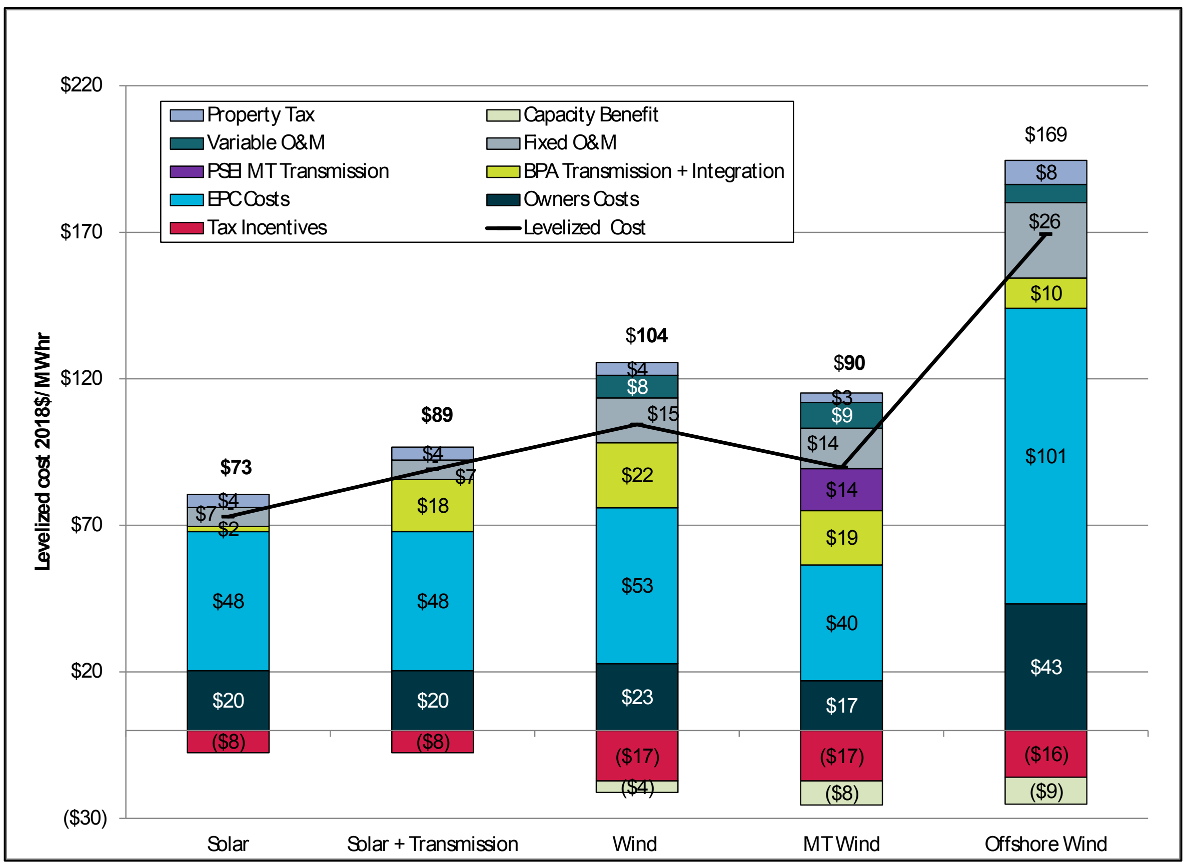
Baseline: Offshore wind not tested in the portfolio analysis.

Sensitivity: Offshore wind tipping point.

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

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

Figure 6-49: Offshore Wind Cost Components



N. Hopkins Ridge Repowering

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

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

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

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

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

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

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

8. COST OF CARBON ABATEMENT ANALYSIS RESULTS

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

Figure 6-51: Carbon Abatement Alternatives Analyzed

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

Methodology

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

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

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

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

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

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

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

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

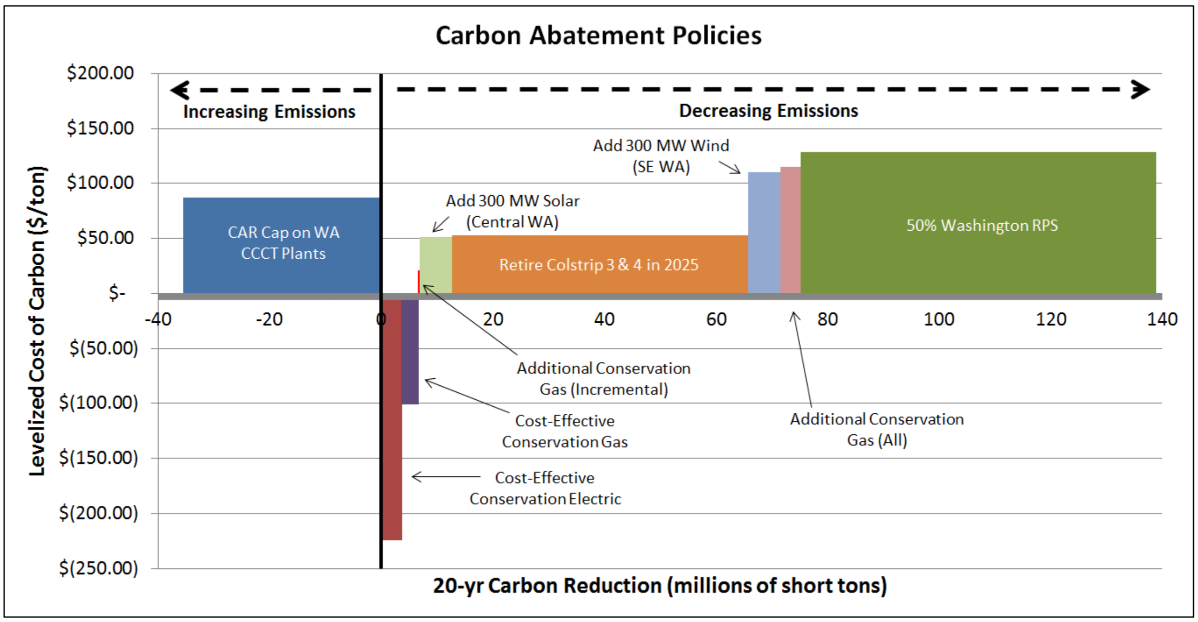
- CAR Cap on Washington CCCT Plants: Similar to the 50 percent RPS, we estimated PSE's cost per ton for the vertical axis of Figure 6-52; then on the horizontal axis, we used the summation of capping all CCCT plant dispatch to estimate the impact on total tons if the policy was applied to all CCCT plants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

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

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

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

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



Key Findings

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

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

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

Figure 6-5: Portfolios Tested for Stochastic Analysis

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

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

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

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

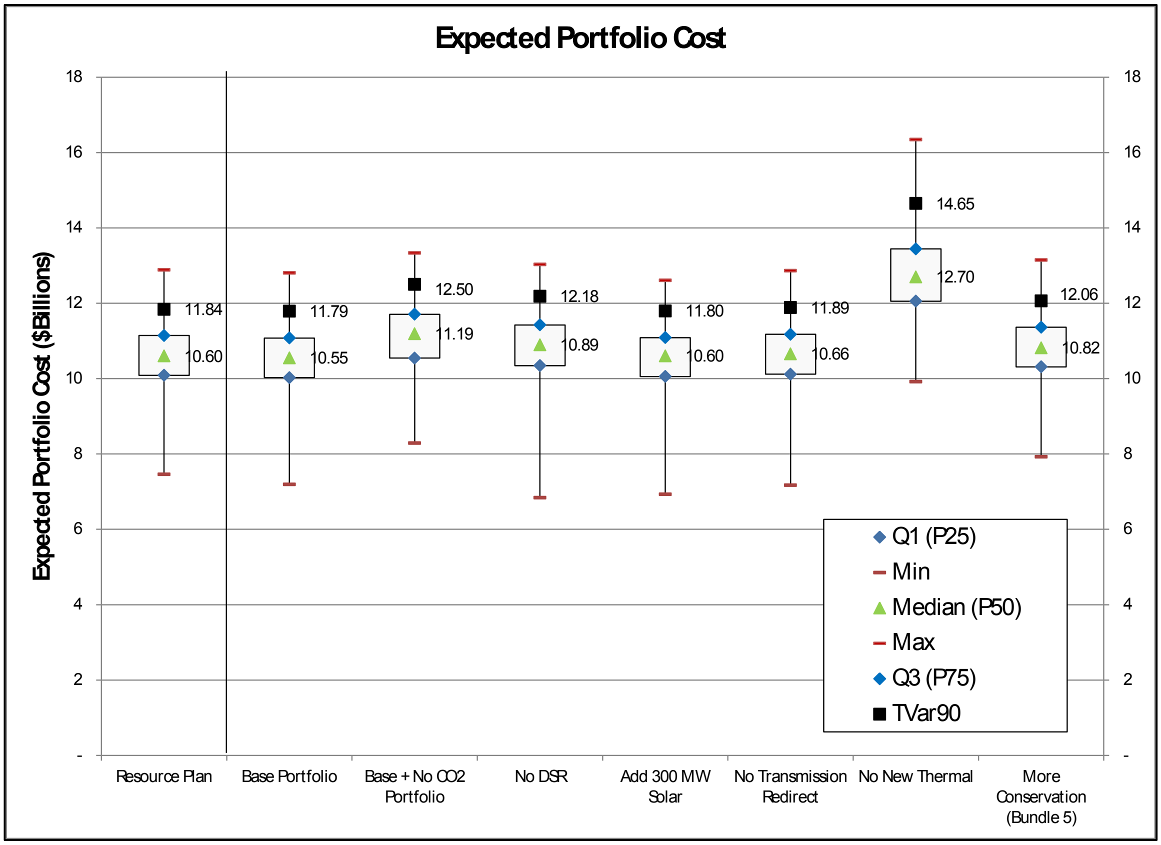
In Figure 6-56 below, the Base + No CO_2 portfolio includes baseload CCCT plants as the lowest cost resource, but since the stochastic analysis takes into account many different futures we see that the mean of the frame peaker portfolio is actually lower cost than the all-baseload gas portfolio.

Figure 6-56: Results of Stochastic Analysis

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

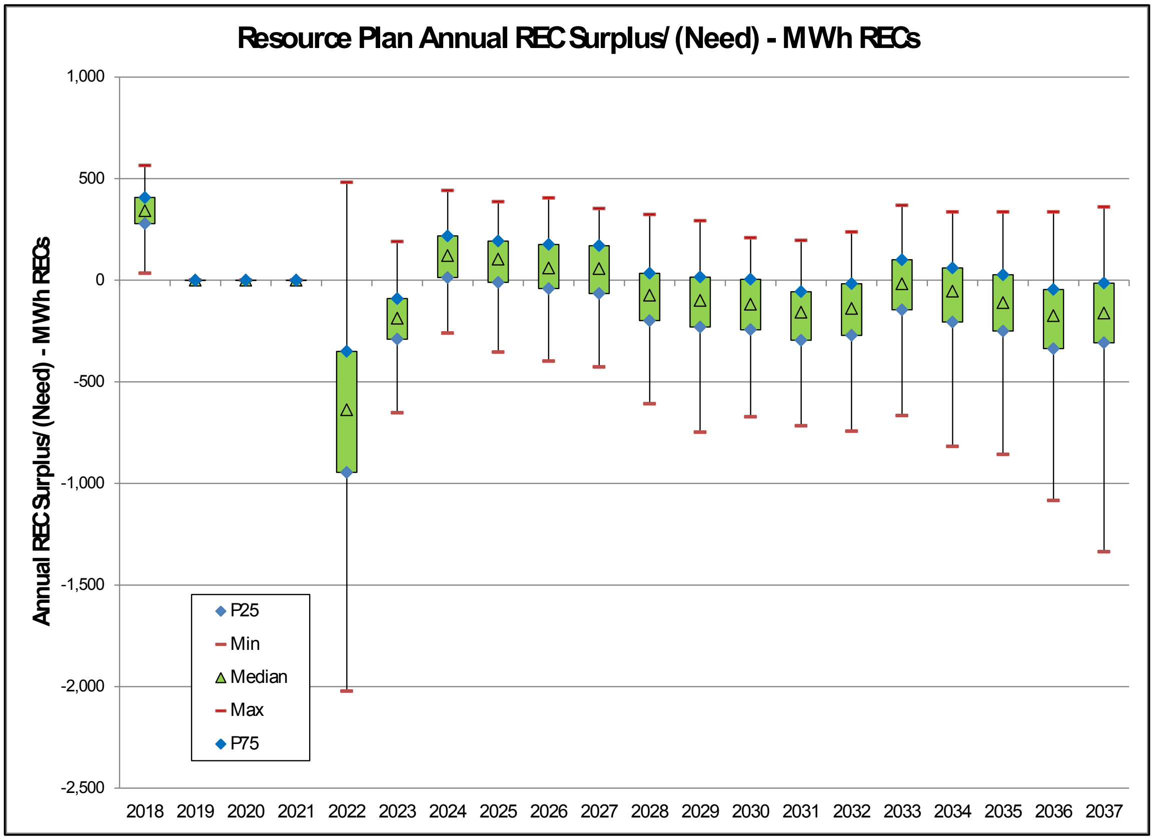
In this IRP, the lowest cost thermal resource varied between the frame peaker and the CCCT depending on the scenario. But the stochastic analysis indicates that frame peakers reduced the cost and risk of the portfolio. This is because the CO_2 regulations modeled targeted baseload thermal plants like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

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



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

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



7

2017 PSE Integrated Resource Plan

Gas Analysis

This analysis 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.

Contents

(continued next page)

1. RESOURCE NEED AND KEY ISSUE

Resource Need

More than 800,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. 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).[1] Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain fairly constant and use per customer is growing slowly, if at all, so the the biggest factor in determining load growth at this time is the increase in customer count.

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2017 IRP Base Demand Forecast, the 2017 IRP High Demand Forecast and the 2017 IRP Low Demand Forecast.[2]

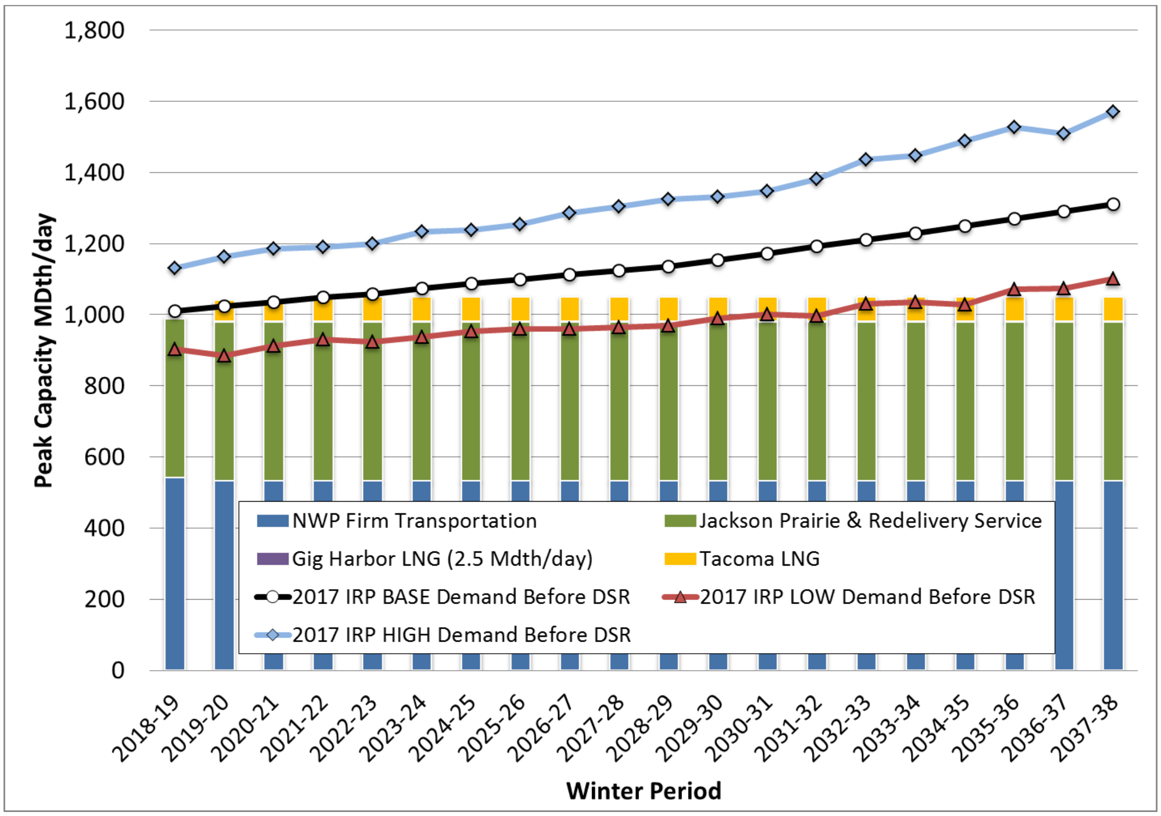
- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need until the winter of 2035/36.
- In the Base Demand Forecast, the first resource need occurs in the winter of 2018/19 in the study, after that, there are sufficient firm resources to meet peak day need until the winter of 2022/23.
- In the High Demand Forecast, we do not have sufficient firm resources to meet peak day need throughout the study.

Figure 7-1 illustrates gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 7-2 shows the resource need surplus/deficit for the Base Demand Forecast.

1 / 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.
2 / The 2017 IRP demand forecasts are discussed in detail in Chapter 5, Demand Forecast.

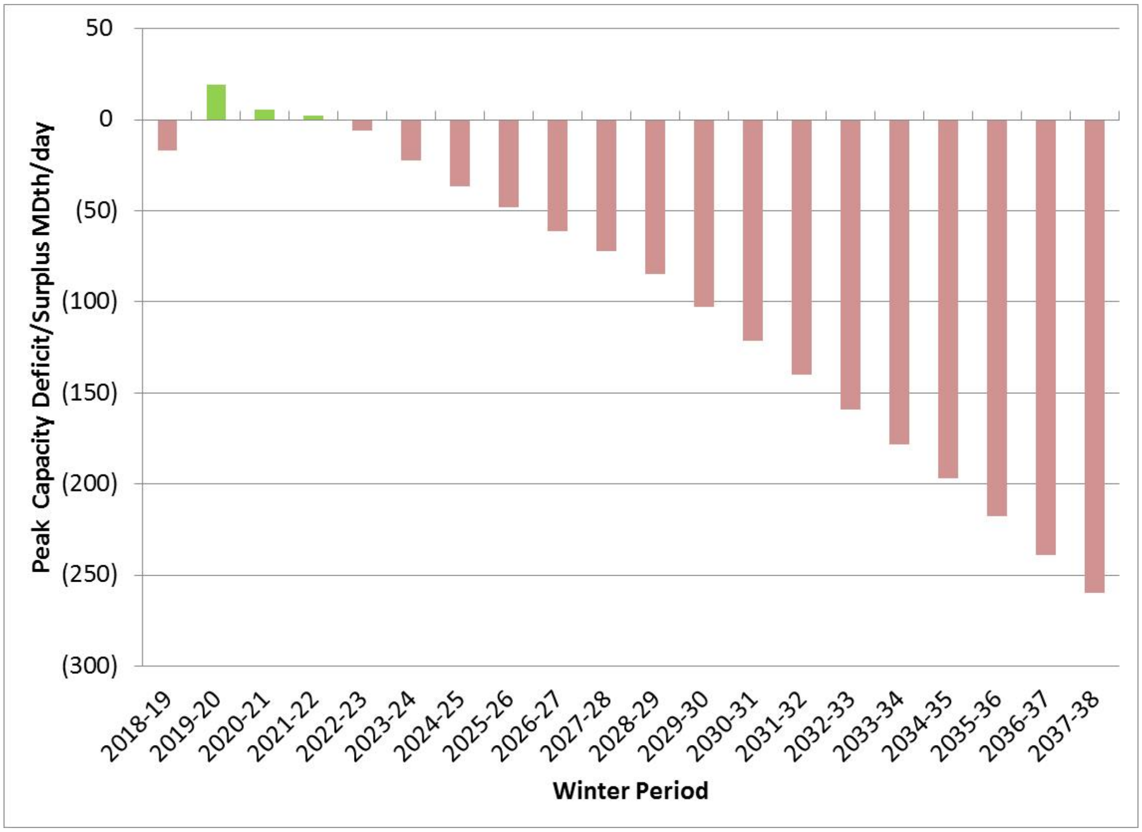
In Figure 7-1, the lines rising toward the right indicate peak day customer demand before demand-side resources (DSR),[3] and the bars represent existing gas supply resources to deliver gas to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[4] The gap between demand and 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)



*3 / 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 2018. These charts and tables are labeled "before DSR."*
4 / Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available by the winter of 2019.

Figure 7-2: Gas Sales Peak Resource Need Surplus/Deficit in Base Demand Forecast before DSR



Gas Sales Key Issue

Adequacy of Sumas Market

The Sumas market (the Huntingdon, British Columbia / Sumas, Washington hub) is essentially an interconnection between the Enbridge/Westcoast Energy Pipeline (Westcoast) and Northwest Pipeline (NWP). Unlike other market hubs, there is no gas production and no convergence of several supply pipelines. PSE implemented a strategy to hold firm capacity on Westcoast for approximately 50 percent of its peak demand for gas from British Columbia (B.C.). This strategy provides a level of reliability (physical access to gas in the production basin) and an opportunity for pricing diversity, as often there is a significant pricing differential between Station 2 and Sumas that more than offsets the cost of holding the capacity.

Since its last major expansion in 2002, Westcoast has had capacity to transport adequate supplies to satisfy all firm demand relying on gas from northeast British Columbia (NE B.C.). Subsequent to the expansion, as Station 2 to Sumas price differentials decline, some shipper contracts expired and were not renewed. This left much of the Westcoast system uncontracted on a firm basis. Then, at the very time the Pacific Northwest (PNW) demand for natural gas to serve gas customer growth and electric generation fuel needs was increasing, conventional production in B.C. began to decline and prices rose, leaving PNW demand to consider the less expensive supplies in the Rockies. The region and California considered new pipeline proposals from the Rockies, and ultimately Ruby Pipeline was built.

The shale revolution changed everything. As production costs fell and supply increased, the abundant and low-cost production of NE B.C. and the Montney region, in particular, is now trapped by a shortage of pipeline capacity leaving the basin. Westcoast is now fully contracted as NE B.C. producers have sought a market outlet for their growing production. In the last two years Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions). This has resulted in adequate supply at Sumas in winter months and an excess in summer months.

A recently completed Westcoast capacity offering was fully subscribed and will drive construction of an additional 105,000 Dth/d of firm capacity on Westcoast and the availability of 94,000 Dth of capacity previously held back for maintenance and reliability reasons, but this is available only on a best-efforts basis. While these new contracts of 199,000 Dth/d will bring more firm gas reliably to the Sumas hub beginning in November 2020, two new large-volume firm demands of approximately 420,000 Dth/d are expected to come online between 2020 and 2023. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand, they will control their own supply and destiny. The firm gas supply controlled by these new industrial loads will effectively remove the supply available at Sumas for other customers on most days.

PSE is comfortable with the notion that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2020, and that PSE would be able to compete (on price) to obtain sufficient supplies in peak periods, even with the new loads.

The table in Figure 7-3 illustrates an approximation of the supply and demand balance at Sumas, currently and in 2020 and 2023. Interruptible loads are shown in blue. The potential start-up of the first of the two new large-volume firm loads – each of which holds their own capacity on Westcoast and thus controls their own supply – may fully absorb all remaining supply at Sumas in winter peak conditions, forcing a rationing of supply among interruptible loads based on price. When the second of the new large-volume firm loads is added, the shortfall in supply (307 MDth/d) is greater than the total interruptible loads (300 MDth/d), which may result in a lack of sufficient gas supply for some firm loads. This would suggest that any additional firm load would require an expansion of Westcoast in order to maintain reliability.

Figure 7-3: Projected Supply and Demand at Sumas

Projected Supply & Demand at Sumas	Current 2017-18		Expected 2020-21		Expected 2023-24	
	Winter MDth/d	Summer MDth/d	Winter MDth/d	Summer MDth/d	Winter MDth/d	Summer MDth/d
Max Westcoast capacity (pre-expansion)	1,518	1,518	1,518	1,518	1,518	1,518
Westcoast Winter Only Firm Service (WOFS)	168	-	168	-	168	-
Westcoast AOS capacity (absorbed by Expansion)	94	94	-	-	-	-
WEI Proposed Expansion (eff. 11/2020)	-	-	199	199	199	199
Max Westcoast capacity -total gas availailable at Sumas	1,780	1,612	1,885	1,717	1,885	1,717
PSE - Guaranteed Access-Firm T-South for Firm Reqmts	**219**	**219**	**219**	**219**	**219**	**219**
PSE -AOS T-South@ 50% for Firm Reqmts	**12**	**11**	-	-	-	-
Remaining Gas Supply available at Sumas	**1,550**	**1,383**	**1,666**	**1,498**	**1,666**	**1,498**
Other Demand						
PSE - Purchase at Sumas for Firm Reqmts	**247**	**123**	**259**	**123**	**259**	**123**
PSE - Purchase at Sumas -Peakers	***155***	***155***	***155***	***155***	***155***	***155***
Fortis BC Energy Firm load	525	275	525	275	525	275
Other Firm Gen. (PGE, Pac.,)	170	170	170	170	170	170
Other Firm LDC (NWN, CNGC, InterMtn, Sierra)	220	125	220	125	220	125
Other Firm Indust. Load (I-5 corridor)	80	70	80	70	80	70
Other Interruptible Gen. (Grays H)	*105*	*105*	*105*	*105*	*105*	*105*
Other Interruptible Indust. Load (I-5 corridor)	*40*	*35*	*40*	*35*	*40*	*35*
NWIW-Kalama from Sumas (eff. 11/2020)	-	-	180	180	180	180
WoodFibre LNG demand at Sumas (eff. 11/2023)	-	-	-	-	240	240
Total Demand	1,542	1,058	1,734	1,238	1,974	1,478
Uncommitted supply at Sumas	**8**	**325**	**(67)**	**261**	**(307)**	**21**
potential unserved	**-**	**-**	**3%**	**n/a**	**14%**	**n/a**
Percent of PSE Firm Requirements covered by T-South	**48.3%**	**65.2%**	**45.8%**	**64.1%**	**45.8%**	**64.1%**
Percent of PSE Total Requirements covered by T-South	**36.5%**	**45.2%**	**34.6%**	**44.0%**	**34.6%**	**44.0%**
PSE Pro-rata share of unserved volume (MDth/d)	**-**	**-**	**16**	**n/a**	**64**	**n/a**

Because there is an equilibrium of supply and firm demand in peak winter periods and a surplus in summer periods, PSE does not believe it is necessary to secure additional firm Westcoast capacity beyond the current level, which is approximately 50 percent of PSE's peak period demand. However, we do believe that there is a potential for inadequate capacity to bring sufficient supply to Sumas in peak periods beyond 2023, assuming the two new large-volume loads materialize. Therefore, in this IRP, we are continuing to assume that any new NWP capacity from Sumas that PSE would consider using to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast from the supply source in NE B.C., in order to be deemed a reliable new resource. PSE will continue to monitor developments in the NE B.C. supply and capacity market and to analyze the implications on an ongoing basis.

2. 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 long-term 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. Such resources would include the consideration of renewal or extension of existing resources.

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 14.3.0 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 11 scenarios for this IRP gas analysis. 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 four 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. **DEMAND-SIDE RESOURCES.** How much does DSR reduce cost and risk? This sensitivitity compares a portfolio with all cost-effective DSR per RCW 19.285 to a portfolio with no DSR in which all future needs are met with supply-side resources.
2. **RESOURCE ADDITION TIMING OPTIMIZATION**. How does the timing of PSE-controlled resource additions affect resource builds and portfolio costs? Instead of offering PSE-controlled resources every two years, the model is allowed to offer them every year.
3. **ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE**. Would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation? This sensitivity applies an alternate discount rate that is lower than PSE's approved weighted average cost of capital (WACC) on residential savings.
4. **ADDITIONAL GAS CONSERVATION.** What happens if DSR is added beyond what is cost-effective per RCW 19.285? This sensitivity adds two additional demand-side bundles above the bundles chosen as cost effective.

Gas portfolio analysis is discussed in more detail in Appendix O, Gas Analysis.

3. 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 firm capacity with NWP.

- 532,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada (AECO); the Rocky Mountain Basin (Rockies) 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 7-4 below. In addition, please see Figure 7-5 for details of PSE's gas sales pipeline capacity.

Figure 7-4: Pacific Northwest Regional Gas Pipeline Map

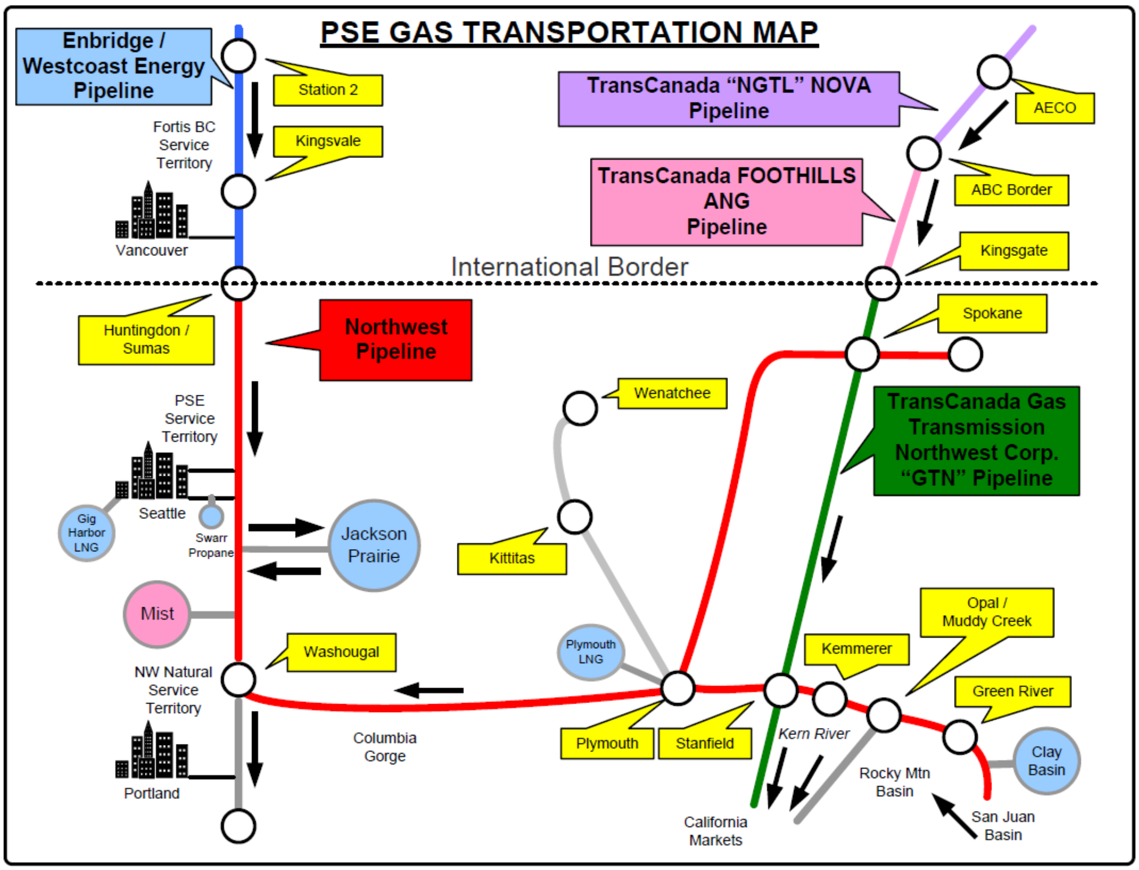


Figure 7-5: Gas Sales - Firm Pipeline Capacity (Dth/day) as of 03/31/2017

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2018-22	2023+
Direct Connect				
NWP/Westcoast Interconnect (Sumas)	1,2	277,237	20,416	256,821
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936
NWP/various in US Rockies	1	179,699	840	178,859
Total TF-1		**532,872**	**21,256**	**511,616**
NWP/Jackson Prairie Storage Redelivery Service	1,3	447,057	-	447,057
Storage Redelivery Service		**447,057**	**0**	**447,057**
Total Capacity to City Gate		**979,929**	**21,256**	**958,673**

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2018-22	2023+
Upstream Capacity				
TC-Alberta/from AECO to TC-BC Interconnect (A-BC Border)	4	79,744	79,744	-
TC-BC from TC-Alberta to TC-GTN Interconnect (Kingsgate)	4	78,631	70,604	8,027
TC-GTN from TC-BC Interconnect to NWP Interconnect (Spokane)	5	65,392	-	65,392
TC-GTN from TC-BC Interconnect to NWP Interconnect (Stanfield)	5,6	11,622	-	11,622
Westcoast/from Station 2 to NWP Interconnect (Sumas)	7,8	132,401	132,401	-
Total Upstream Capacity	**9**	**367,790**	**282,749**	**85,041**

NOTES
1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
2. After planned transfer of 10,000 Dth/day effective 11/1/2019 to Puget LNG to provide service to TOTE.
3. Storage redelivery service (TF-2 or discounted TF-1) 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.
4. Converted to approximate Dth per day from contract stated in gigajoules per day.
5. TC-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. Converted to approximate Dth per day from contract stated in cubic meters per day.
8. The Westcoast contracts contain a right of first refusal upon expiration.
9. 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. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point. Firm shippers have the right to temporarily alter the contractual receipt point, the delivery point and even the flow direction – subject to availability of capacity for that day. The reliability of this use of "alternate firm" can be reasonably predicted; it is very reliable if the contract is used to flow gas in the contractual direction to or from the primary delivery or receipt point (i.e., within the primary path).

Alternate firm is much less reliable or predictable if used to flow gas in the opposite direction or "out of path." While this capacity has higher rights than interruptible capacity, it is not considered reliable in most circumstances. 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 (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 on an alternate basis, outside of their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner as “within path” or “out of path” modes, along with the ability to create “segmented release” capacity has resulted in very low interruptible volumes on the NWP system.

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 of the flexibility of its firm contracts and 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 firm storage redelivery service transportation allows us to contract for less year-round pipeline capacity to meet winter-only or peak-only demand.
- PSE also uses storage to balance city gate gas receipts from gas marketers 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 Gas Storage Project (Jackson Prairie) in Lewis County, Wash. is an aquifer-driven storage field, located in the market area, 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-long gas supply. Figure 7-6 presents details about storage capacity.

Figure 7-6: Gas Sales Storage Resources[1] as of 03/31/2017

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie – PSE Owned	398,667	156,000	8,528,000	N/A
Jackson Prairie – PSE Owned[2]	(50,000)	(50,000)	(500,000)	2019
Net JP Owned	**348,667**	**106,000**	**8,028,000**	
Jackson Prairie – NWP SGS-2F[3]	48,390	18,935	1,181,021	2023
Jackson Prairie – NWP SGS-2F[3]	6,077	2,378	178,460	2026
Jackson Prairie – NWP SGS-2F[4]	(6,077)	(2,378)	(178,460)	2020
Net Jackson Prairie	**397,057**	**124,935**	**9,209,021**	
Clay Basin[5]	107,356	53,678	12,882,750	2018/20
Clay Basin[6]	(33,333)	(16,667)	(4,000,000)	2018
Net Clay Basin	**74,023**	**37,011**	**8,882,750**	
Total	**471,080**	**161,946**	**18,091,771**	

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 (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve gas sales customers.

3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.

4. Released to Cascade Natural Gas Co. through 4/1/2020.

5. PSE expects to renew the Clay Basin storage agreements.

6. Assigned to third parties through 3/31/2018; PSE is considering renewal.

Jackson Prairie Storage

PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which is operated by PSE under FERC authorization. As shown in Figure 7-5, PSE owns 398,667 Dth per day of firm storage withdrawal rights and associated storage capacity from Jackson Prairie. Some of this capacity has been made available to PSE's electric portfolio at market rates. The firm withdrawal rights – but not the storage capacity – may be recalled to serve gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, PSE has access to 48,390 Dth per day of firm deliverability and associated firm seasonal capacity through contracts for SGS-2F storage service from NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. As shown in Figure 7-4, PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts renew automatically 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

Dominion-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 7-5, 4,000,000 Dth of this storage capacity has been released to third parties through March 2018. PSE is considering the extension of these arrangements.

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 (or 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 the 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. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

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 7-7: Gas Sales Peaking Resources

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Transportation Tariff	Availability
Gig Harbor LNG	2,500	2,500	10,500	On-system	current
Swarr LP-Air [1, 2]	10,000	16,680	128,440	On-system	Nov. 2019+
Tacoma LNG [3]	59,500	2,000	538,000	On-system	Nov. 2019
TOTAL	**92,000**	**21,680**	**682,190**		

NOTES
1. Swarr is currently out of service, pending upgrades to reliability, safety and compliance systems, to be considered in resource acquisition analysis for an in-service date of November 2019 or later.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill, or 16,680 Dth/day.
3. Planned in-service date of Nov. 1, 2019. Withdrawal capacity will rise in the future when the distribution system is upgraded, and again when an additional 10 MDth/day will be subscribed by a third party (assumed to be available starting Nov 2021).

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 compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering 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 on two years' notice as early as the 2019/20 winter season. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

PSE expects the completion of construction and successful start-up of this LNG peak-shaving facility to serve the needs of core gas customers as well as regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project will achieve economies of scale that reduce costs for core gas customers. This project is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2017 IRP assumes the project is put into service in sufficient time to be a reliable resource for the 2019/20 heating season, providing 59.5 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 assumed to be available (as a new resource) beginning in the 2020/21 heating season.

Existing Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to gas supplies. Not only has development of shale beds in British Columbia 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 or high local demands. This separation cycle can last several years, but is usually 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 forecasted 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 Nova (NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (GTN) 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 enters into month-long or multi-month 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 to our customers since 1993.[5] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[6] 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 2016 have saved a cumulative total of over 5 million Dth, which equates to approximately 300,000 metric tons of CO_2 emissions – more than half of which has been achieved since 2007.

Energy savings targets and the programs to achieve those targets are established every two years. The 2014-2015 biennial program period concluded at the end of 2015. The current program cycle is January 1, 2016 through December 31, 2017. The majority of gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

PSE spent over $13.5 million for natural gas conservation programs in the most recent complete program year of 2016, compared to $3.2 million in 2005. Spending over that period increased more than 25 percent annually. In the last ten, years the savings have been in the range of 3 to 4 millions of therms per year. Savings reached a peak in 2009 at just over 5 million therms. The low cost of gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. 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.

For the 2016-2017 period, PSE has a two-year target of approximately 7.4 million therms in energy savings; savings of 4,480,000 therms were achieved in 2016. 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. Figure 7-8 summarizes energy savings and costs for 2014 through 2016.

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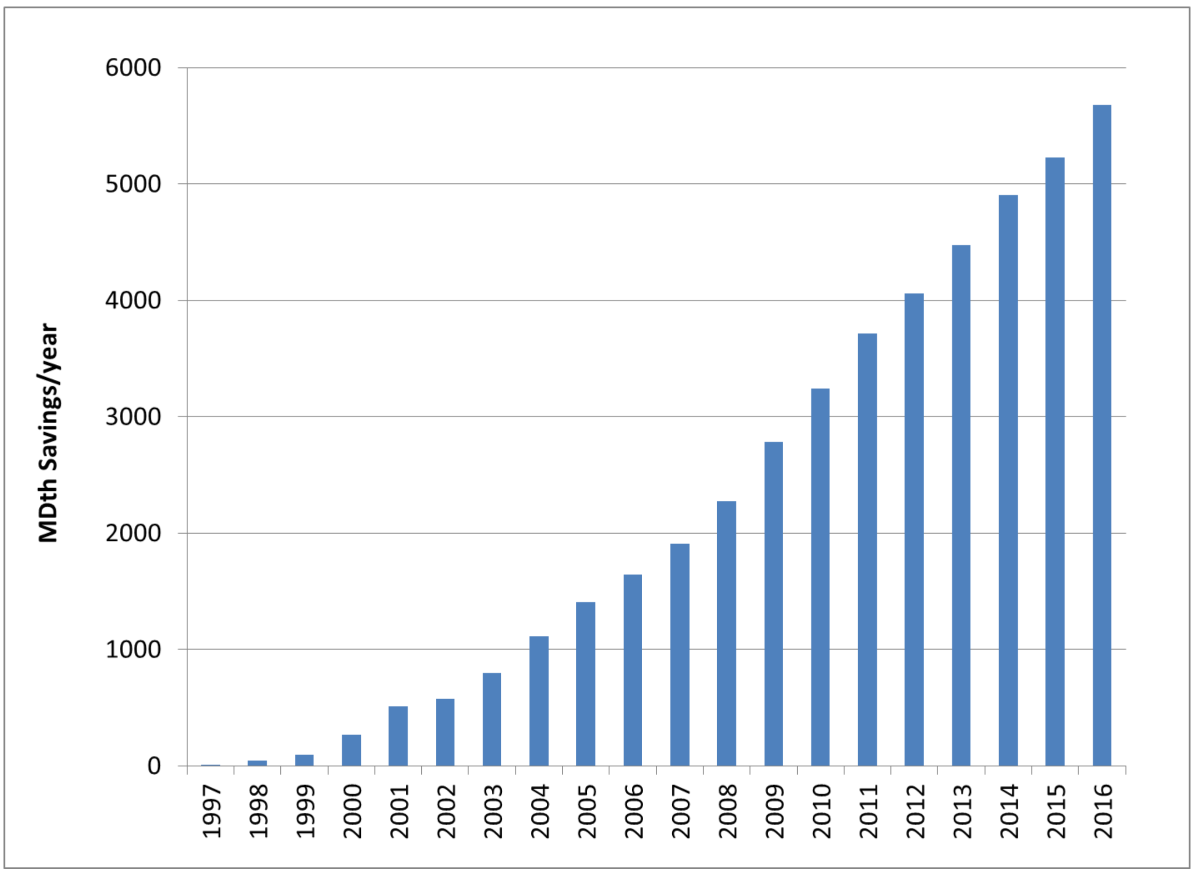
5 / Demand-side resources, also called conservation, are resources that are generated on the customer (demand) side of the meter.
6 / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 7-8: Gas Sales Energy Efficiency Program Summary, 2014 – 2016
Total Savings and Costs

Program Year	Actual Savings (Therms)	Actual Cost ($)	Target Savings (Therms)	Budget ($)
2014	4,346,000	$ 11,888,000	3,880,000	$11,927,000
2015	3,242,000	$13,094,000	3,081,000	$13,140,000
2016	4,480,000	$13,644,000	3,963,000	$14,714,000

Figure 7-9: Cumulative Gas Sales Energy Savings from DSR, 1997 – 2016



5. 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.

The following acronyms are used in the descriptions below.

- AECO – the Alberta Energy Company trading hub
- LP-Air – liquid propane air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP – Northwest Pipeline
- TC-Foothills – TransCanada-Foothills Pipeline
- TC-GTN – TransCanada-Gas Transmission Northwest Pipeline
- TC-NGTL – TransCanada-NOVA Gas Transmission Pipeline
- Westcoast - Enbridge/Westcoast Energy Pipeline

Combination # 1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning Novermber 2021, 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 believes it will be necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity at Sumas.

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 November 2017 to October 2020 only. PSE believes that the vast majority of under-utilized firm pipeline capacity in the I-5 corridor will be absorbed by other new loads by Fall 2020. Beyond October 2020, other long-term resources would be added to serve PSE 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 Westcoast. Availability is estimated beginning November 2021. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills 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-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

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 and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 5 – LNG-related Distribution Upgrade

This combination assumes completed construction and successful commissioning of the LNG peak-shaving facility for the 2019/20 heating season, providing 59.5 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Combination # 6 – Mist Storage and Redelivery

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 with significant additional volume contracting by other parties.

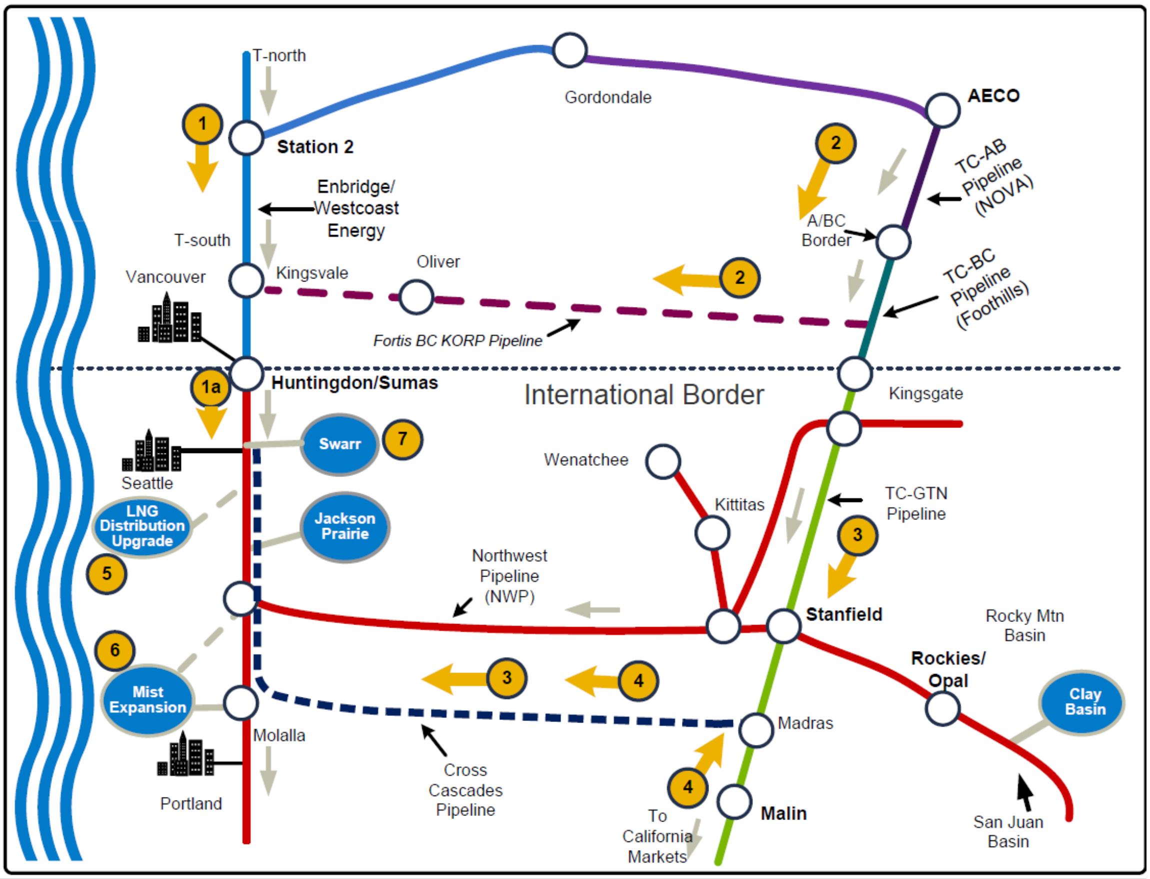
Combination # 7 – Swarr LP-Air Upgrade

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.

NOTE: Options 2, 3, 5, and 6 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the gas sales resource alternatives is depicted in Figure 7-10 below.

Figure 7-10: PSE Gas Transportation Map Showing Supply Alternatives



Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 7-11 below.

Figure 7-11: 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 2021), or in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2021.
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 November 2021.

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 (Enbridge/Westcoast Energy's B.C. pipeline), 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/NIT[7] trading hub and transport it to interconnect with the proposed Cross Cascades pipeline on a firm basis. FortisBC and Westcoast have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO/NIT supplies.

7 / *AECO-Nova Inventory Transfer*

Figure 7-12: Upstream Pipeline Alternatives Analyzed

Upstream Pipeline Alternatives	Description
Increase Westcoast Capacity (Station 2 to PSE) *(from Combination 1)*	Acquisition of new 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 new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT gas to Stanfield for delivery to PSE city gate via the proposed Cross Cascades pipeline and a northbound upgrade of NWP.
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 new capacity on the TC-NGTL and TC-Foothills pipelines.

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-NGTL and TC-Foothills pipelines, would improve access to the AECO/NIT 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 Gas Storage Project, 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.

LNG-related Distribution System Upgrade

This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Mist Expansion

NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., would consider a potential expansion project to be completed in 2021/22. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2021, once the Mist upgrade 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, making the use of Mist storage cost-effective. Since this resource is dependent on other parties willingness to contract for an expansion, this resource availability is not in PSE's control.

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 on two years' notice for the 2019/20 heating season or beyond.

Figure 7-13: Storage Alternatives Analyzed

Storage Alternatives	Description
Distribution upgrade allowing greater utilization of Tacoma LNG *(Combination 4)*	Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG pea-shaving beginning the 2021-22 heating season.
Expansion of Mist Storage Facility *(Combination 6)*	Considers the acquisition of expanded Mist storage capacity, based on estimated cost and operational characteristics. Assumes a 20-day supply at full deliverability of up to 100 MDth/day beginning the 2021-22 heating season.
Swarr LP-Air Facility Upgrade *(Combination 7)*	Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2019-20 heating season.

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. In this IRP, the achievability factors were changed from 75 percent to 85 percent to be consistent with the electric measures. Also, all gas measures were given a 10 percent conservation credit similar to the 10 percent conservation credit electric measures receive stemming from the Power Act of 1980. 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 2." The Codes 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 7-14 shows the twelve 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 7-14: DSR Cost Bundles and Savings Volumes (MDth/year)

	WACC		Alternate Discount	
	2027	2037	2027	2037
Codes & Standards	1,175	2,705	1,175	2,705
Bundle 1: <$0.22	657	961	519	710
Bundle 2: $0.22 to$0.30	721	1,125	721	1,125
Bundle 3: $0.30 to $0.45	1,183	1,879	1,202	1,902
Bundle 4: $0.45 to $0.55	1,298	2,086	1,299	2,089
Bundle 5: $0.55 to $0.70	1,513	2,458	1,514	2,462
Bundle 6: $0.70 to $0.85	1,610	2,657	2,913	5,218
Bundle 7: $0.85 to $0.95	1,697	2,750	2,918	5,233
Bundle 8: $0.95 to $1.20	2,995	5,424	4,280	7,122
Bundle 9: $1.20 to $1.50	3,733	6,536	4,625	7,604
Bundle 10: $1.50 to $2.00	4,843	7,994	5,033	8,180
Bundle 11: >$2.00	10,959	16,151	10,933	16,107

More detail on the measures, assumptions and methodology used to develop DSR potentials can be found in Appendix J, Conservation Potential Assessment.

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 7-15 illustrates the methodology described above.

Figure 7-15: General Methodology for Assessing Demand-side Resource Potential

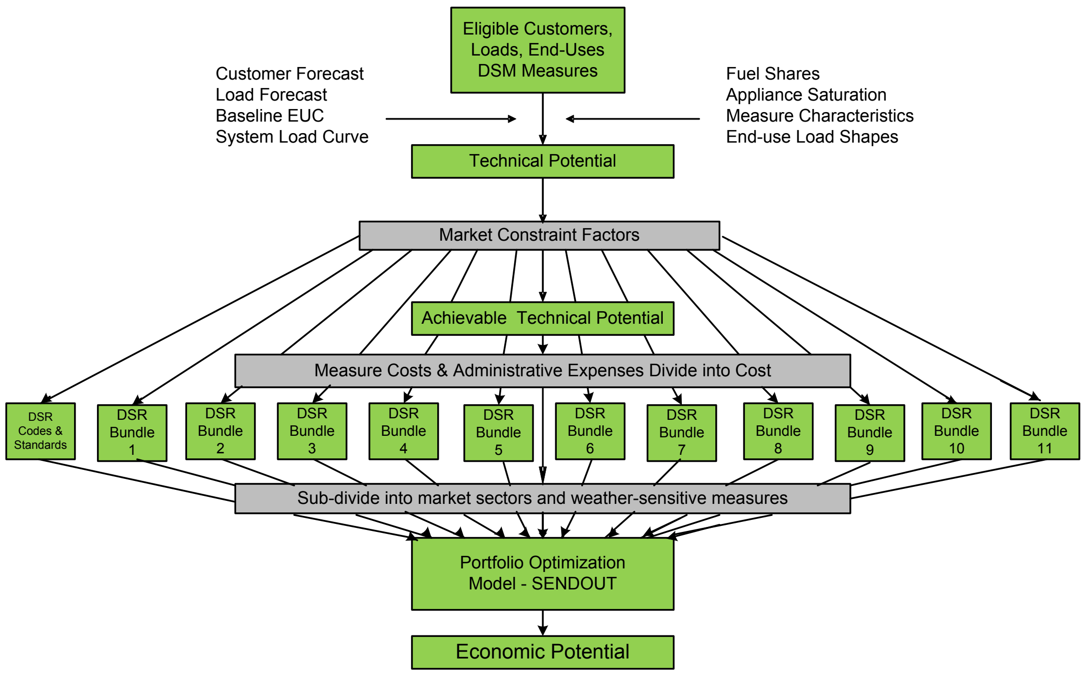


Figure 7-16 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side gas resource for a particular scenario.

Figure 7-16: Demand-side Resources – Achievable Technical Potential Bundles

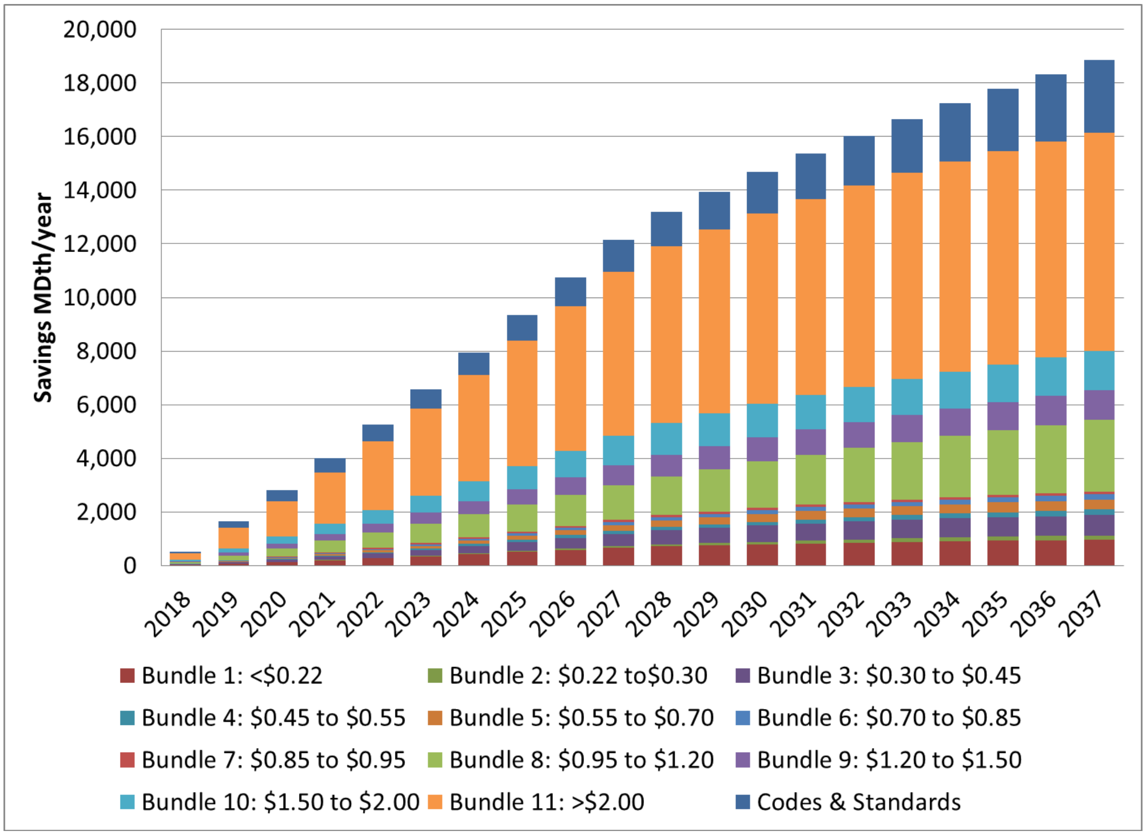
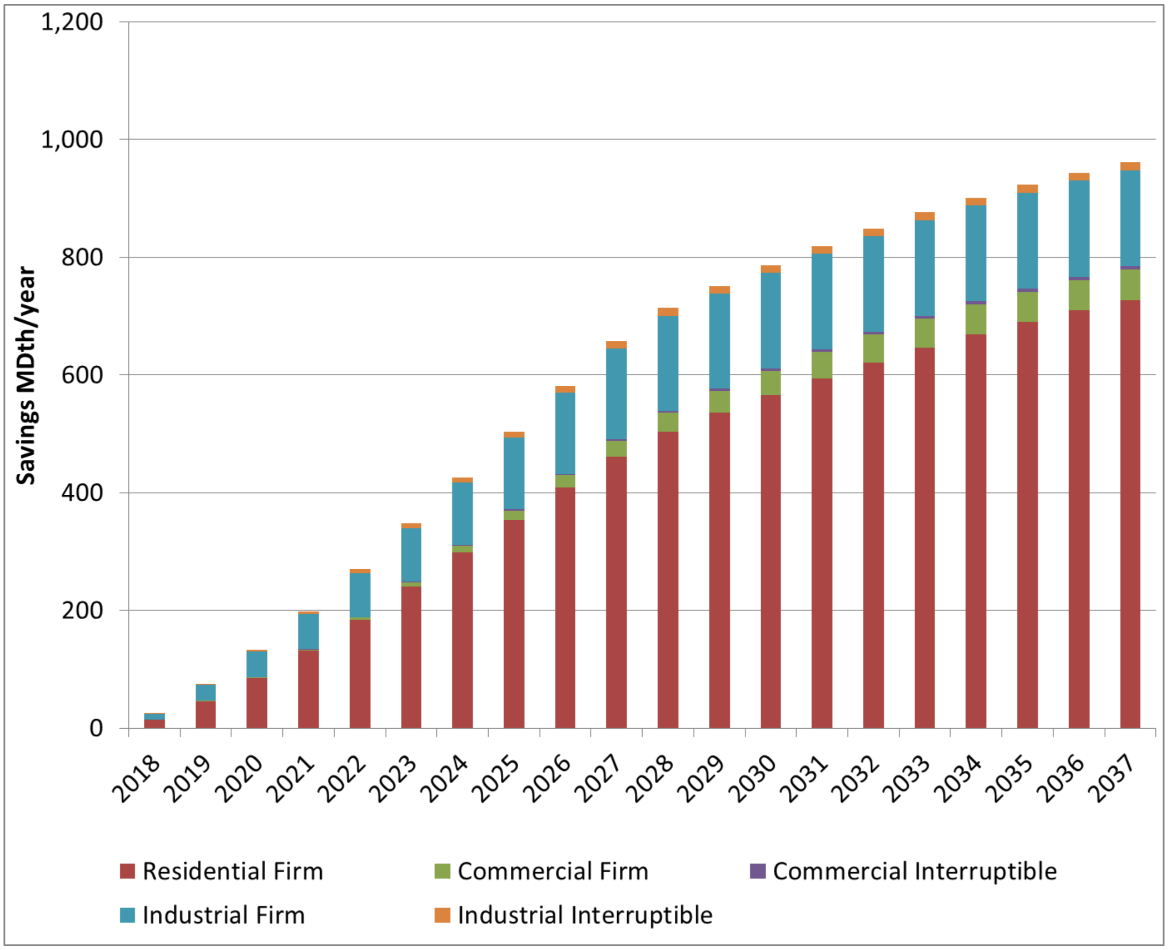


Figure 7-17 shows a sample input format subdivided by customer class for Bundle 1 (<$2.20 per Dth) used in the GPM for all the IRP scenarios.

Figure 7-17: Savings Formatted for Portfolio Model Input by Customer Class – Bundle 1 (< $2.20/Dth)



6. 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 for the winter of 2018/19 and each year beginning the winter of 2022/23.** The High Scenario shows a current and growing resource shortfall, while in the Low Scenario the gas sales portfolio is surplus until the winter of 2035/36.
2. **Immediate short-term need will be met with combination of two resources in the Base Scenario: demand-side resources and a short-term contract for firm pipeline capacity from Sumas to PSE.** In the High Scenario the short-term pipeline contract along with immediate implementation of the Swarr LP-Air facility upgrade and the LNG related distribution upgrade will still leave PSE short until new pipeline capacity can be built for winter 2021/22.
3. **Cost-effective DSR is slightly lower in the 2017 IRP.** The cost-effective bundle is slightly lower on the supply curve compared to the 2015 IRP. The decrease is due to two more years of conservation implementation since the last IRP, a lower demand forecast and updated measure savings and costs. Offsetting these factors was the change in the achievability factor from 75 percent to 85 percent. The result is a slightly lower amount of cost-effective DSR.
4. **The Swarr LP-Air upgrade project is cost effective in all but low demand scenarios** and is expected to provide 30 MDth per day of peaking capacity effective November 2024.
5. **The Tacoma area distribution system upgrade project is cost effective in all scenarios,** allowing Tacoma LNG to reach its full peaking capacity of 85,000 Dth per day starting the winter of 2027/28.
6. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in most scenarios.** The GPM indicates this pipeline capacity is more cost effective as early as 2020/21 in some scenarios and by 2029/30 in most scenarios. While potentially less expensive with greater participation, this capacity does not require participation by other parties. The pipeline alternatives to purchase gas at Malin or AECO and deliver it to PSE's city gate via the TC-GTN pipeline across the proposed Cross Cascades pipeline is chosen only in high demand scenarios by winter 2023/24.

7. **Neither the Mist storage expansion or the Fortis BC KORP project are selected in any scenario.** These options required significant demand by third parties or reliance on other projects, and like the Cross Cascades pipeline project, the feasibility and timing is outside of PSE control.
8. **The carbon cost assumption was significantly higher in the 2017 IRP compared to the 2015 IRP, and this impacted resource choices.** The levelized cost of carbon was almost the same as the levelized gas price in the mid case. We can see that in the Base + No CO_2 Scenario, a lower amount of DSR was cost effective, it was the lowest of the scenarios.

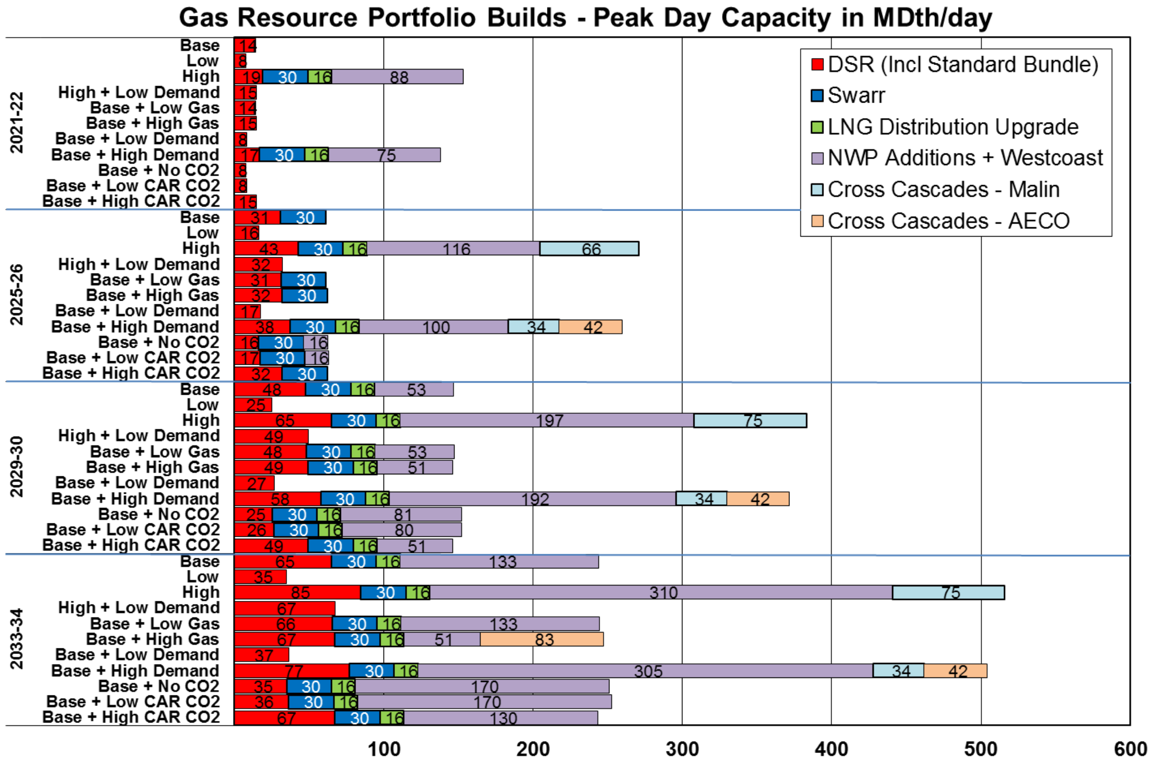
Gas Sales Portfolio Resource Additions Forecast

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 eleven scenarios[8] are illustrated in Figure 7-18 for winter periods 2018/19, 2022/23 and 2030/31. Combination #3, Cross Cascades – AECO, and Combination #4, Cross Cascades – Malin, are chosen only in high demand and high gas scenarios.

8 / *Scenarios are explained in detail Chapter 4, Key Analytical Assumptions.*

Figure 7-18: Gas Resource Additions in 2021/22, 2025/26, 2029/30 and 2033/34 (Peak Capacity – MDth/day)



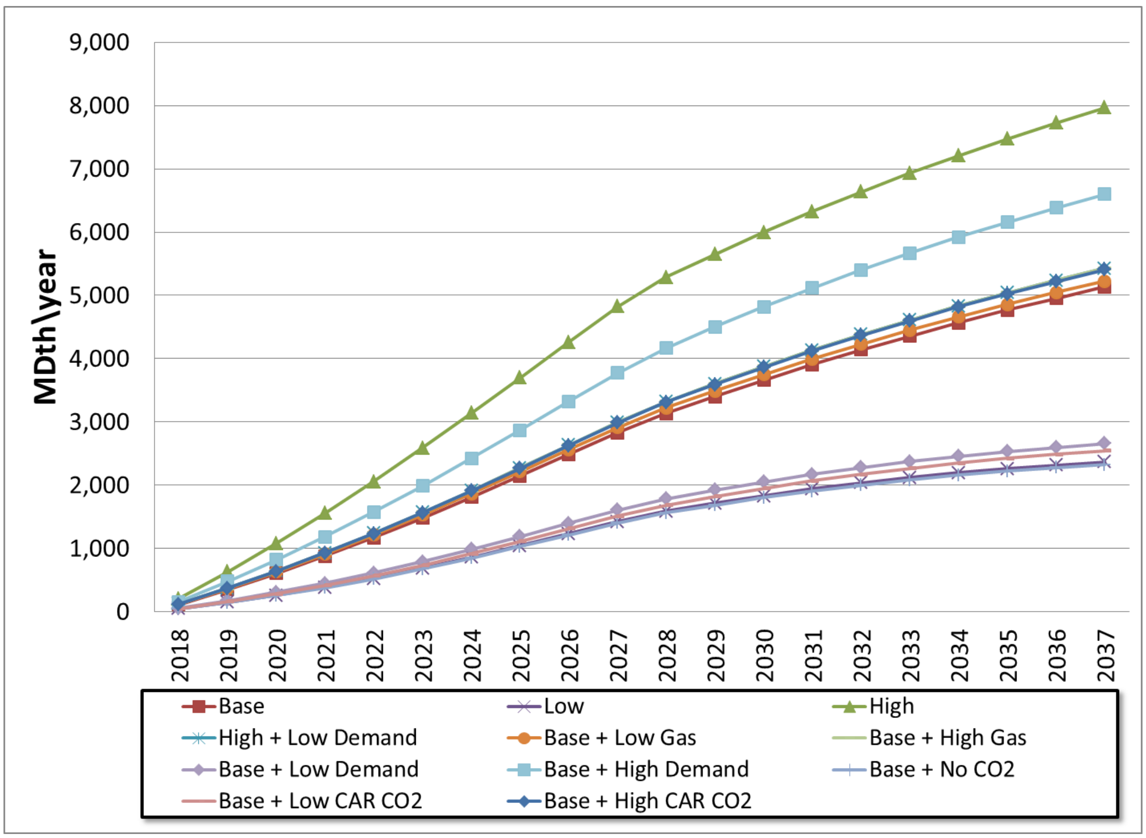
Demand-side Resource Additions

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. Compared to the 2015 IRP, the 2017 IRP carbon costs in the Base Scenario are significantly higher relative to gas prices, which is a function of both declining gas prices and higher carbon cost assumptions. Carbon costs are almost as much as the gas prices in the mid-scenarios.

The sensitivity of DSR to carbon prices is illustrated in Figure 7-19. In the Base Scenario, which includes a CO_2 price, cost-effective DSR is 14 MDth per day by 2021/22, while in the Base + No CO_2 Scenario, the DSR level falls to 8 MDth per day. In terms of gas supply planning, 6 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the IRP Base Scenario increases conservation. In the 2017 IRP scenarios that model high carbon price assumptions, cost-effective DSR increases by 75 percent in the 2021/22 winter period.

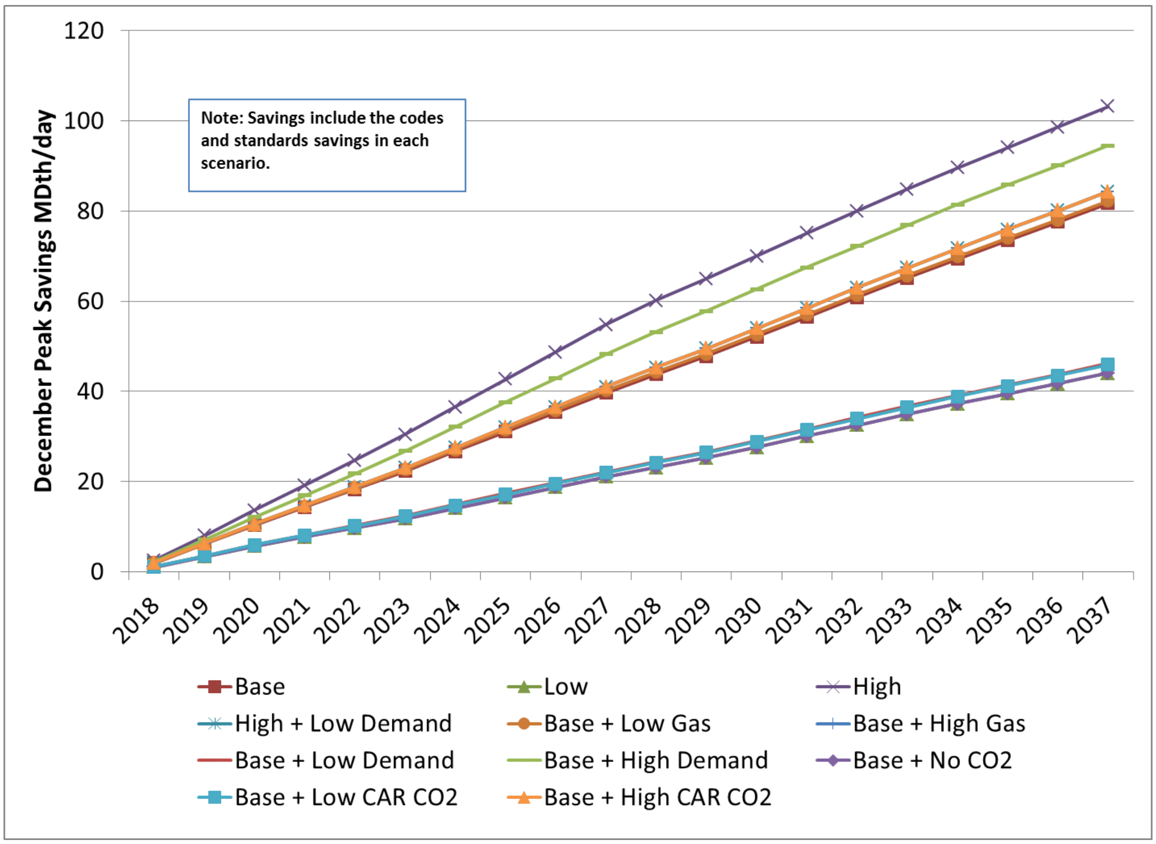
Figure 7-19: Cost-effective Gas Energy Efficiency Savings by Scenario



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 resource plan forecast ranged from roughly 3,800 MDth in 2037 for the Low Scenario to nearly 50 percent higher at 5,700 MDth in 2037 in the High Scenario.

Peak savings by scenario are shown in Figure 7-20.

Figure 7-20: 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 7-21 and 7-22, below. More detail on this analysis is presented in Appendix J, Conservation Potential Assessment.

Figure 7-21: Gas Sales Cost-effective DSR Bundles by Class and Scenario

Bundles	Base	Low	High	High + Low Demand	Base + Low Gas	Base + High Gas	Base + Low Demand	Base + High Demand	Base + No CO2	Base + Low CO2	Base + High CO2
Residential Firm	5 + 8	4	10	8	8	8	5	9	4	4	8
Commercial Firm	6	5	10	8	6	8	6	10	5	6	8
Commercial Interruptible	6	5	8	8	6	8	6	6	3	5	7
Industrial Firm	3	3	3	3	3	3	3	3	3	3	3
Industrial Interruptible	3	3	3	3	3	3	3	3	3	3	3

Figure 7-22: Gas Sales Cost-effective Annual Savings by Class and Scenario

Savings (MDth/year)	Base	Low	High	High + Low Demand	Base + Low Gas	Base + High Gas	Base + Low Demand	Base + High Demand	Base + No CO2	Base + Low CO2	Base + High CO2
Residential Firm	3,346	776	5,690	3,436	3,436	3,436	867	4,343	776	1,388	3,436
Commercial Firm	1,463	1,101	1,750	1,282	1,460	1,463	1,282	1,750	1,101	1,282	1,463
Commercial Interruptible	126	108	143	108	126	143	126	126	19	108	127
Industrial Firm	353	353	353	353	353	353	353	353	353	353	353
Industrial Interruptible	29	29	29	29	29	29	29	29	29	29	29

Overall, the economic potential of DSR in this IRP is slightly lower than in the 2015 gas sales Base Scenario, and slightly lower-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 7-23 below).

The downward shift in the overall savings is due to several factors.

- Past program accomplishments have lowered future achievable potentials.
- Updates to the measure costs and savings.
- Building stock data has been updated using the Commercial Building Stock Assessment.
- A lower demand forecast in the 2017 IRP.

On the other hand, inclusion of a higher CO_2 price in the Base Scenario increased conservation, because it made the overall levelized cost of gas in the 2017 IRP Base Scenario comparable to the 2015 IRP Base Scenario, even though the underlying gas commodity prices had declined. For more information on how gas sales DSR differs in the 2017 IRP vs. the 2015 IRP, see Appendix J, Conservation Potential Asessment.

Figure 7-23: Cost-effective Gas Energy Efficiency Savings, 2015 IRP vs 2017 IRP

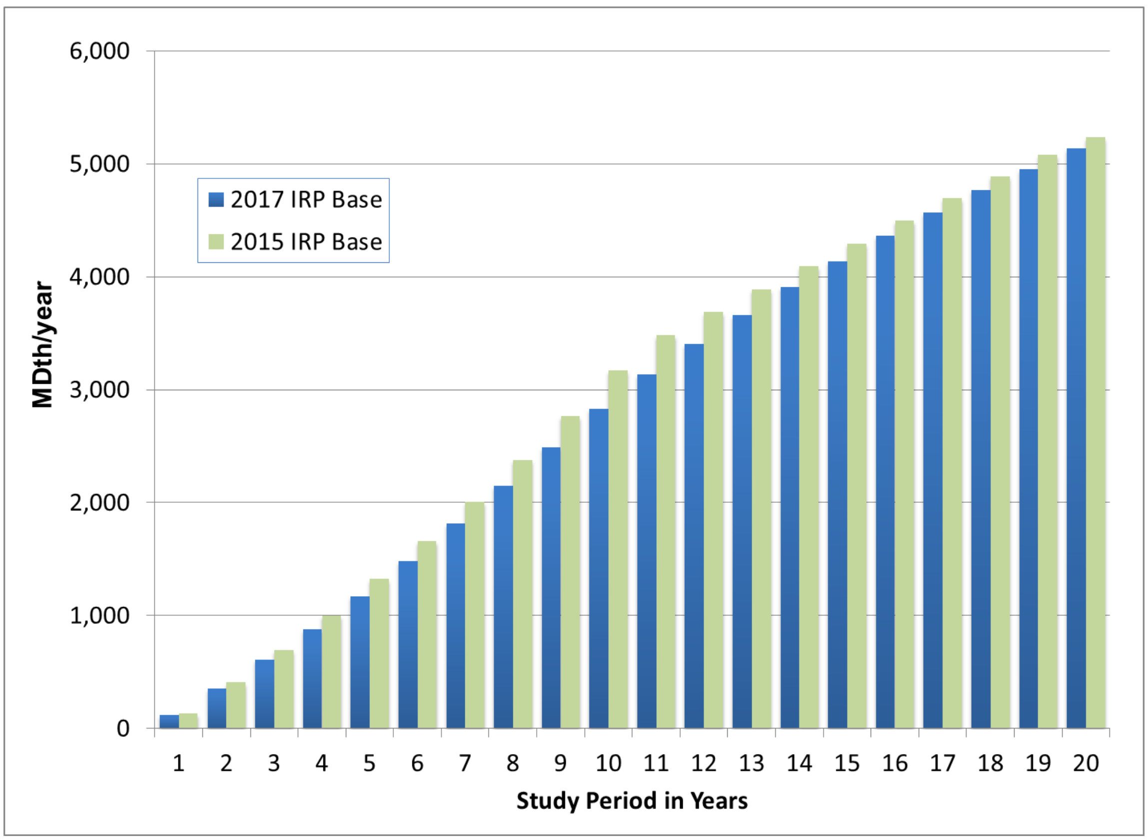


Figure 7-24 below compares PSE's energy efficiency accomplishments, current targets and the new range of gas efficiency potentials as determined by the analysis. In the short term, the 2017 IRP indicates an economic potential savings of 397 to 618 MDth for the 2016-2017 period.[9] The

9 / These savings are based on a no-intra year ramping, which are used to set conservation program targets.

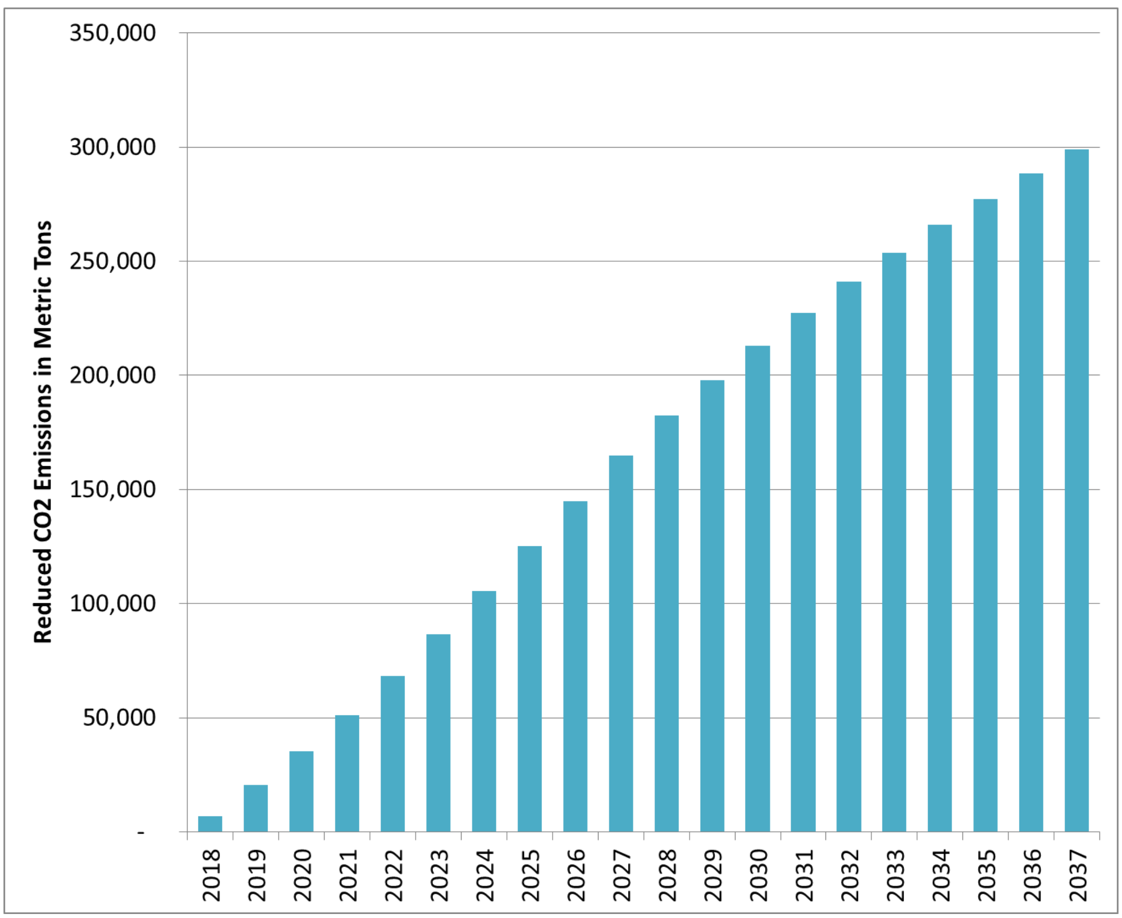
694 MDth target for the current 2016-2017 period is higher than this range. These two-year program accomplishments and projections show a downward trend for the reasons discussed above.

Figure 7-24: Short-term Comparison of Gas Energy Efficiency in MDth

Short-term Comparison of Gas Energy Efficiency	Dth over 2-year program
2014-2015 Actual Achievement	759
2016-2017 Target (updated January 2017)	801
2018-2019 Range of Economic Potential	147-633

Figure 7-25 shows the impact on CO_2 emissions from energy efficiency measures selected in the Base Scenario.

Figure 7-25: CO_2 Emissions Reduction from Energy Efficiency in Base Scenario



Peaking Resource Additions

The Swarr LP-Air upgrade project was selected as least cost (and as the first long-term resource) in all but the low demand scenarios, preceding the Tacoma LNG-related distribution upgrade by two to three years.

Distribution Upgrade Related to Tacoma LNG Project

PSE is in the construction phase of this small-scale natural gas liquefaction and LNG storage facility located within its service territory, which will serve the peaking needs of PSE's core gas customers and the growing demand for LNG as a marine and vehicle transportation fuel. The Tacoma LNG Project was found to be cost effective in every scenario of the 2015 IRP, however, with the revised load forecast, the full 85 MDth per day of LNG is not required initially. In the 2017 IRP, Tacoma LNG is modeled as an existing resource of 59.5 MDth per day beginning in 2019/20, growing to 69 MDth per day by 2021/22. PSE studied the optional resource of a planned upgrade to the distribution system that would allow the plant to deliver the full 85 MDth per day. The GPM selected the distribution upgrade to be effective in 2029/30 or earlier in all but the low demand scenarios.

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 least cost. 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 November 2018 through October 2019, when Tacoma LNG will be on line.

The Sumas to PSE 2018-2019 short-term contract was selected in most scenarios. Based on lower costs, in most scenarios the GPM chose some of the NWP and Westcoast pipeline expansion to purchase gas from Station 2 as cost effective by 2029/30, after the peaking resources, increasing the capacities in subsequent years.

The Cross Cascades projects which source gas from either Malin or AECO through Stanfield across the proposed Cross Cascades pipeline were selected only in high demand scenarios as early as 2022/23. The NWP + KORP pipeline alternative was more expensive and not chosen in any scenario.

Storage Additions

The Mist storage expansion was not selected in any scenario.

Observation

All of the selected resources (listed here in general order of least cost) – DSM, Swarr LP-Air, Tacoma LNG-related distribution upgrade and Northwest + Westcoast Pipeline expansion – are within PSE's control. The timing of individual projects can be fine-tuned by PSE in response to load growth, and none of these projects rely on participation by any other contracting party to be feasibly implemented.

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 7-26 and 7-27, respectively. Note that Combination #2, Fortis BC/Westcoast (KORP), was not chosen in any of the years. Again, additional scenario results are included in Appendix O, Gas Analysis.

Figure 7-26: Gas Sales Base Scenario Resource Portfolio

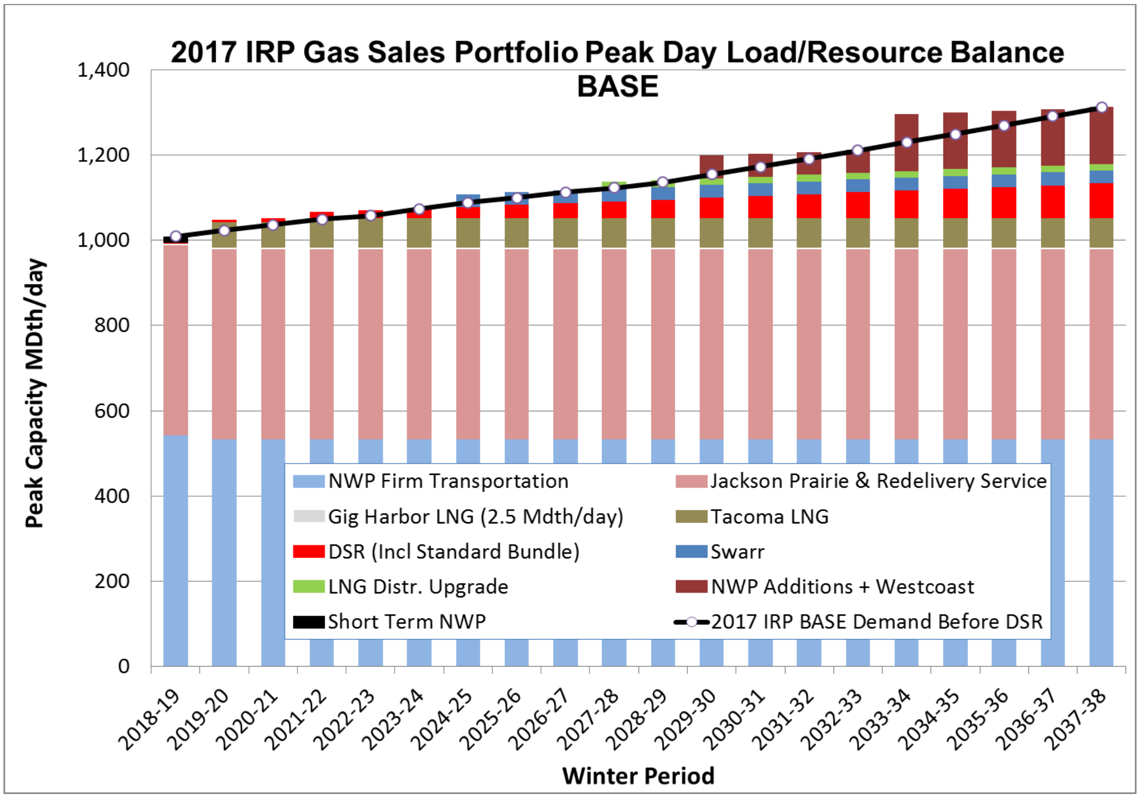


Figure 7-27: Gas Sales Base Scenario Resource Portfolio (table)

Base Scenario – MDth/day	2021-22	2025-26	2029-30	2033-34	2037-38
Demand-Side Resources	14	31	48	65	82
7- Swarr Propane-Air Upgrade	-	30	30	30	30
5- LNG Distribution Upgrade	-	-	16	16	16
1- NWP/Westcoast Expansion	-	-	53	133	133
3- Cross-Cascades from Malin Expansion	-	-	-	-	-
4- Cross-Cascades from AECO Expansion	-	-	-	-	-
6- Mist Storage/ NWP Expansion	-	-	-	-	-
2- NWP/KORP Expansion	-	-	-	-	-
Total	14	61	147	244	261

Average Annual Portfolio Cost Comparisons

Figure 7-28 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 LP-Air, 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 7-28: Average Portfolio Cost of Gas for Gas Sales Scenarios

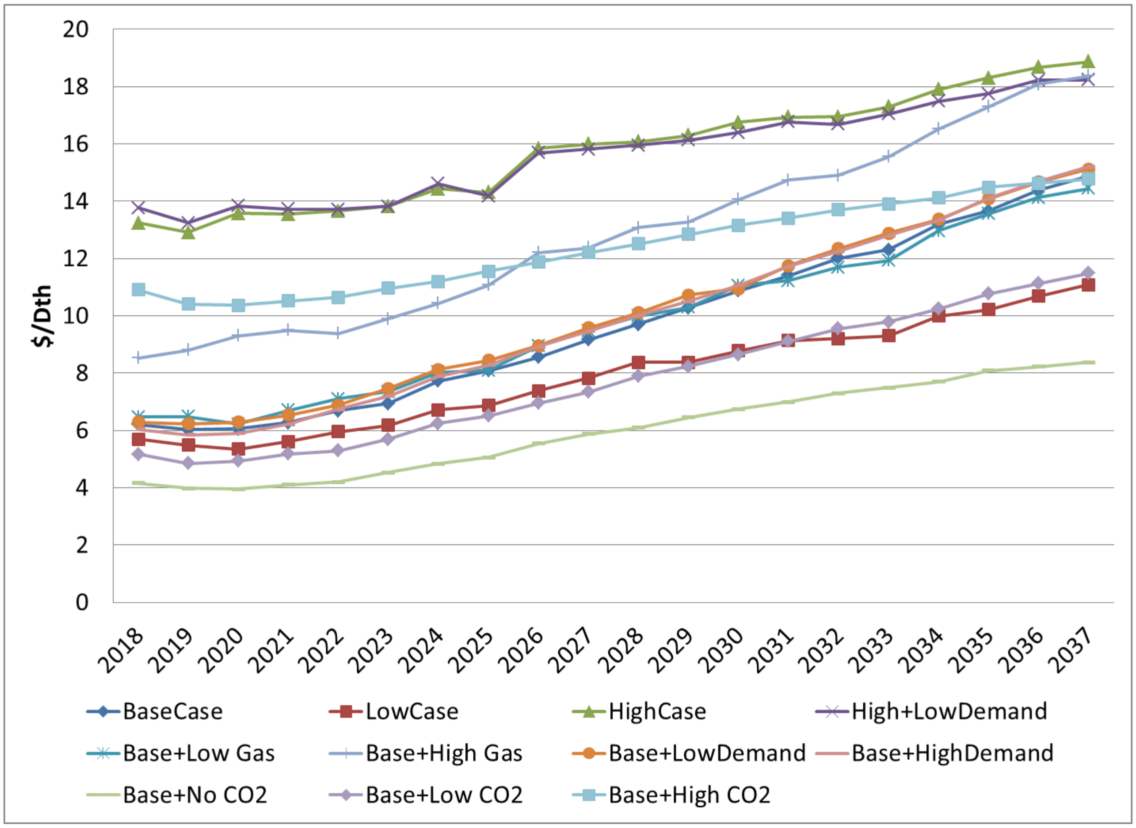


Figure 7-28 shows that average optimized portfolio costs are heavily impacted by the gas prices and CO_2 cost assumptions included in each scenario.

- 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 + Low Gas scenarios.
- Scenario costs range from $4.16 to $13.23 per Dth in 2018 to $8.37 to $18.87 per Dth in 2037.
- The Base Scenario portfolio costs are about $6.2 per Dth in 2018, increasing to about $14.90 per Dth by 2037.
- The highest average system cost was in the High Scenario, which ranged from $13.23 per Dth in 2018 to $18.87 per Dth in 2037. 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 Base + No CO_2 Scenario, which ranged from $4.16 per Dth in 2018 to $8.87 per Dth in 2037. This is because this scenario had the lowest gas plus CO_2 price assumptions. The results show that the relatively high CO_2 cost compared to the gas price has a significant impact on system costs.

Sensitivity Analyses

Four sensitivities were modeled in the gas sales analysis for this IRP. Sensitivities start with the Base Scenario portfolio and change one resource. This allows PSE to evaluate the impact of a single resource change on the portfolio.

1. DEMAND-SIDE RESOURCES
BASELINE: All cost-effective DSR per RCW 19.285 requirements.
SENSITIVITY > No DSR, all future resource needs are met in with supply-side resources.

2. ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE
BASELINE: All demand-side resources are evaluated using the weighted average cost of capital (WACC) assigned to PSE.
SENSITIVITY > Evaluate residential DSR using an alternate discount rate. The WACC is still applied to commercial and industrial energy efficiency measures.

3. RESOURCE ADDITION TIMING OPTIMIZATION
BASELINE: Swarr LP-Air and the LNG distribution system upgrade are built starting in 2019 and 2021 respectively, and offered every two years in the model.
SENSITIVITY > Swarr and the LNG distribution system upgrade are allowed every year starting in 2019 and 2021 respectively.

4. ADDITIONAL GAS CONSERVATION
BASELINE: All cost-effective DSR per RCW 19.285 requirements.
SENSITIVITY: Add two more demand-side bundles above the cost-effective demand-side bundles.

Demand-side Resources

In the Base Scenario the portfolio model assumes all cost-effective DSR per RCW 19.285 requirements. The portfolio model is then run a second time with demand-side resource alternatives removed as an option, and the model meets need with only supply-side resource alternatives. The results show that portfolio costs are significantly lower in the Base Scenario where demand-side resources are offered and are selected to optimize the portfolio. The net present value of the portfolio with demand-side resources is lower by about $360 million.

Alternate Residential Conservation Discount Rate Sensitivity

An alternate discount rate was applied to the demand-side resource alternative in this sensitivity analysis (one that was lower than PSE's assigned WACC) to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as 1) the 3-month average of a long-term 30-year nominal treasury rate for residential customer class,[10] and 2) the WACC discount rate for the commercial and industrial customer classes. The treasury rate used for developing the residential bundles was 2.94 percent. The impact was to shift measures to the lower cost point on the conservation supply curve.

This alternate discount rate was used to estimate the achievable DSR potential for the new DSR bundles (see Figure 7-14). These "alternate discount rate" bundles were then input into the gas portfolio model to obtain the cost-effective level of DSR.

The residential bundles chosen with the alternate discount rate were at a lower point on the supply curve for the residential class, and they remained unchanged for the commercial class of customers. The net effect was that cost-effective savings from residential customers was slightly higher. This impact was muted due to the "lumpiness" of the supply curve. The Base Scenario bundle had a significant jump in savings in Bundle 8, and when the alternate discount rate was used to redevelop the supply curve, the large savings shifted to lower point on the supply curve and moved to Bundle 6. This resulted in the model selecting Bundle 6, since it was likely able to satisfy the resource need with lower cost and a higher amount of conservation. In Bundle 6, cost-effective savings in the commercial and industrial bundles was the same as in the Base Scenario, as these bundles were not affected by the discount rate.

See Figure 7-29 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 slightly by the end of the twentieth year (see Figure 7-30). 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.

10 / Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2017

Figure 7-29: Cost-effective Level of Gas DSR for Residential Customer Class, Base vs. Alternate Discount Rate

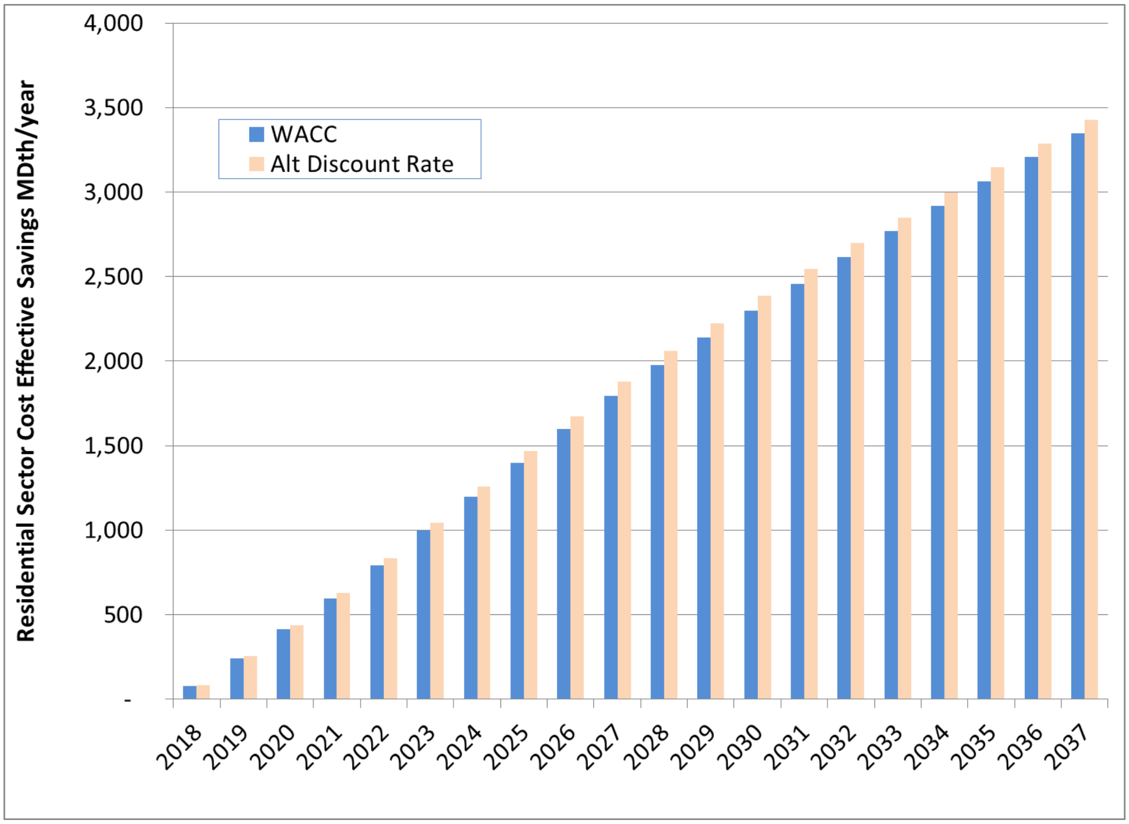
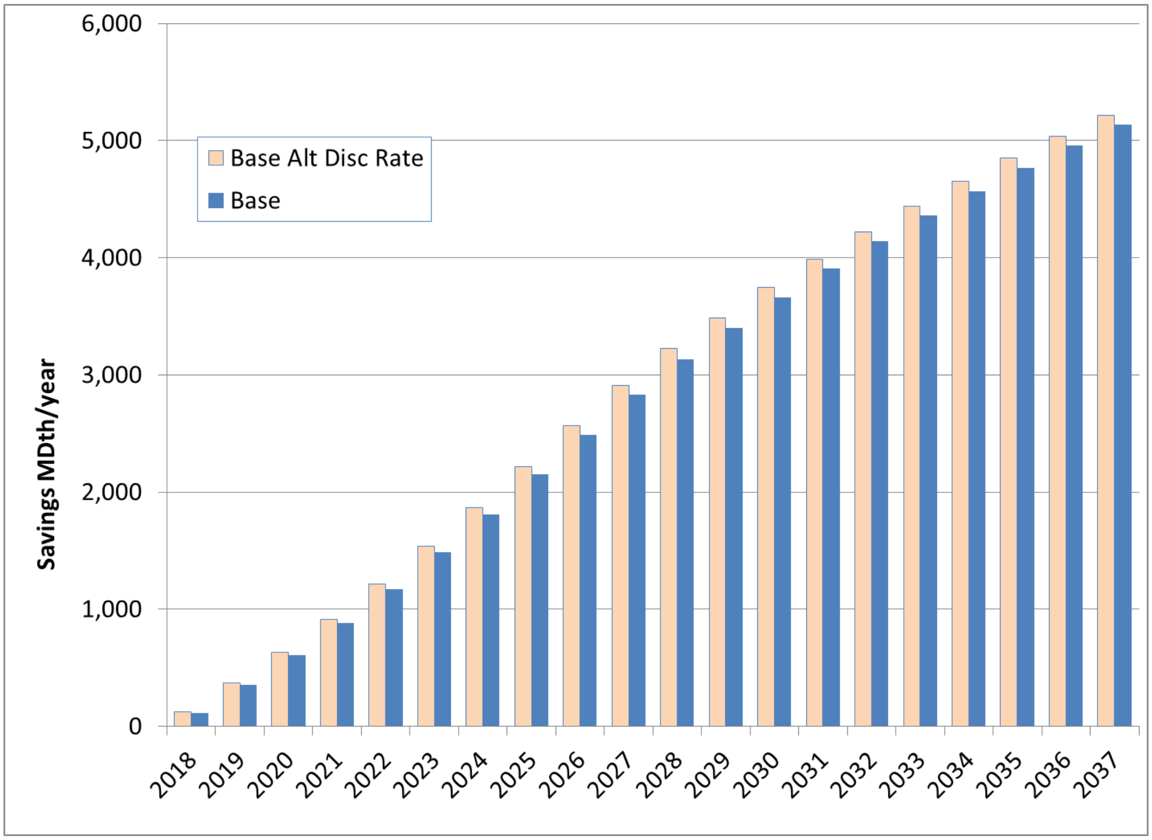


Figure 7-30: Cost-effective Level of Gas DSR,
Base vs. Alternate Residential Conservation Discount Rate



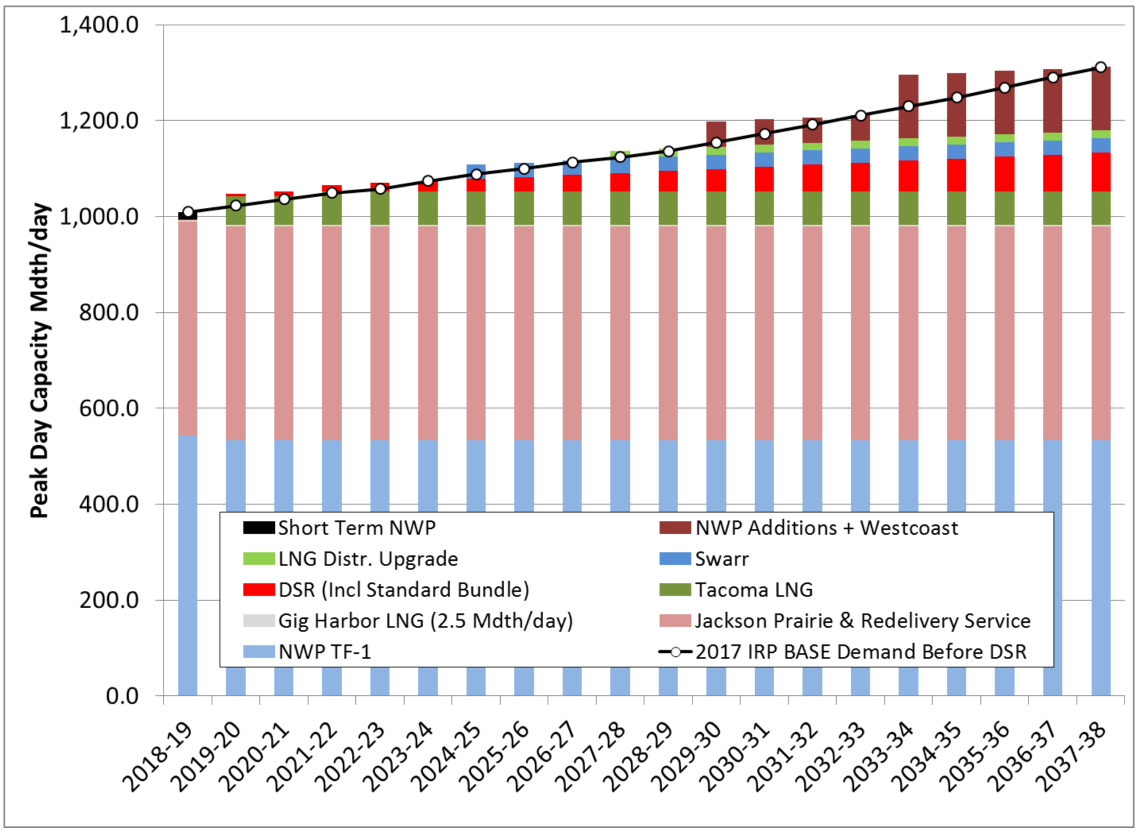
Resource Addition Timing Optimization

Two of the supply-side resources are projects that PSE would implement to increase peaking capacity: Swarr and the LNG distribution system upgrade. The timing for these resources is in PSE's control, and the lead times are short enough that these resources can be developed with a year's notice. Therefore, the Base Scenario was tested to allow these resources to be built in any given year. Swarr is available starting in November of 2019 and the LNG distribution upgrade is offered first in November 2021. Given that PSE is surplus, and the first need occurs in the winter of 2022/23, these resources are not needed in the near term in any case. However, by looking at the annual expansion option, we can determine in what year the resource is needed and we can determine if that will produce a lower portfolio cost.

KEY FINDINGS. Reflecting the flexibility PSE has in timing the Swarr and LNG distribution upgrades makes slight changes in the timing of resource builds and lowers the overall NPV portfolio cost.

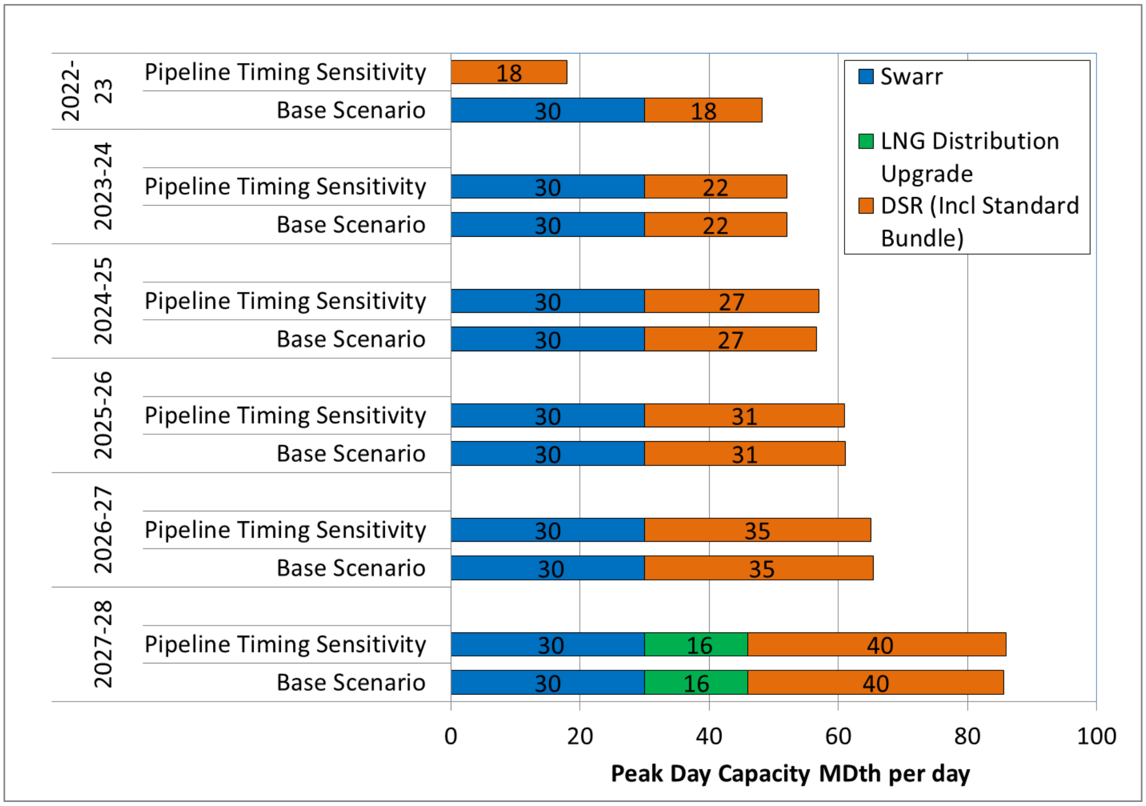
As shown in Figure 7-31, the result was a slightly smoother load/resource balance in the first ten years when Swarr and LNG distribution upgrades are selected instead of the step or "lumpy" resource additions that can be seen in in the latter half of the study when pipeline additions are offered every four years.

Figure 7-31: Timing Sensitivity Gas Resource Portfolio



The portfolio builds for the timing sensitivity are shown in comparison with the Base Scenario portfolio in Figure 7-32 below. The chart below shows that the Swarr and LNG distribution upgrade additions are the same in the Base Scenario as in the timing sensitivity, the only difference being that Swarr is delayed by one year in the timing sensitivity. All the other resource additions are unchanged.

Figure 7-32. Timing Sensitivity Impact on Other Resource Builds



PORTFOLIO COST IMPACTS. Results indicate the revised timing of resource additions from the pipeline timing sensitivity reduce portfolio costs. The 20-year NPV of cost for the Base Scenario portfolio was $8,799 million. The 20-year NPV cost for the pipeline timing sensitivty portfolio was $8,797 million – a slight reduction in portfolio cost..

Additional Gas Conservation

The cost-effective amount of conservation in the Base + No CO_2 Scenario was used as the basis for this analysis. Figure 7-33 shows the two levels of additional DSR bundles that were tested. The incremental approach estimated the cost of reducing carbon using two additional DSR bundles, and a second approach added all 10 of the DSR bundles.

Figure 7-33: Additional Conservation Bundles Tested

DSR Bundle	Base No CO2	Incremental DSR	All DSR
Residential Firm	4	6	10
Commercial Firm	5	7	10
Commercial Interruptible	3	5	10
Industrial Firm	3	5	10
Industrial Interruptible	3	5	10

NOTE: Incremental DSR is two bundles over the cost effective bundles in the Base + No CO_2 portfolio.

The additional bundles in the two cases were forced into the SENDOUT portfolio optimization model and both the total system costs and incremental carbon reduction was compared to the Base + No CO_2 portfolio. The results are shown in Figure 7-34 below.

Figure 7-34: Cost of Emission Reduction with Additional Conservation

	Base Deterministic Portfolio Cost (Levelized Millions $)	Difference from Base (Millions $)	Regional Emissions (Levelized Million Tons)	Difference from Base (Millions Tons)	Cost of Carbon Reduction ($/ton)
Base + No CO2 (Reference) GAS	$5,599		59.77		
Additional Conservation – Incremental GAS	$5,601	$2	59.69	0.08	$20.45
Additional Conservation – All GAS	$5,768	$169	58.30	1.47	$114.83

The cost of carbon reduction increases as you move up on the gas conservation supply curve. The amount of conservation is dependent on the distribution of the conservation resources on the supply curve; it is non-linear, and so the impact on emissions can vary.

8

2017 PSE Integrated Resource Plan

Delivery Infrastructure Planning

This chapter describes the planning process for PSE-owned gas and electric delivery infrastructure and outlines the challenges and opportunities that confront the delivery system at this time.

Contents

(continued next page)

1. OVERVIEW

Delivery system infrastructure planning is done on a 10-year basis, and those plans are updated continually as conditions, technologies and customer behavior change. This chapter reviews PSE's responsibilities and existing system, what drives infrastructure investment, the planning process, 10-year infrastructure plans, and current challenges and opportunities. It also describes the process for determining the system need, clarifying alternatives, and preliminary solutions or solutions funding approval.

System planning is a complex process that involves evaluation of system needs and alternatives to address those needs. External input is a major component of the planning process. For large projects, stakeholder engagement throughout project development is extensive. In addition to a general description of those steps, this chapter includes a detailed description of the Energize Eastside Transmission Capacity Project to illustrate the evaluation, analysis and community involvement PSE performs in the process of making system improvement decisions.

Currently, PSE is in the process of upgrading its delivery system infrastructure to support smart grid enhancements; this will enable us to achieve cost-effective efficiencies and expand customer offerings. Replacement of legacy analog networks and obsolete remote telemetry unit equipment began in 2010 and is expected to be completed within the next five years. This includes modern, IP-based SCADA networks that will be used to control and monitor substation, transmission and generation assets and replacement of aging Automated Meter Reading (AMR) communications system and electric customer meters with Advanced Metering Infrastructure (AMI) that enables two-way communication. These steps are necessary to build the foundation to efficiently integrate maturing technologies. Among those we are integrating and studying are distributed generation, energy storage, conservation voltage reduction and demand response. While PSE expands integration of these alternatives, we will need to be mindful of the dependability of the technology under all conditions such that customer reliability and rates are not harmed by technologies and applications that are not effectively scalable. Additionally, the technologies and integration must be compatible with existing grid standards and tariffs. This makes informing customers and stakeholders about the capability and viability of these technologies an important priority for PSE.

2. SYSTEM OVERVIEW

Responsibilities

PSE's delivery system is responsible for delivering natural gas and electricity through pipes and wires safely, reliably and on demand. We are also responsible for meeting all regulatory requirements that govern the systems. To accomplish this, we must do the following[1].

- Operate and maintain the system safely and efficiently on a year-by-year, day-by-day and hour-by-hour basis.
- Accomplish timely maintenance and reliability improvements.
- Meet state and federal regulations and complete compliance-driven system work.
- Ensure that gas and electric systems meet both peak demands and day-to-day demands.
- Ensure that localized growth needs are addressed when they differ from overall system growth needs.
- Meet the interconnection needs of independent power generators that choose to connect to our system.
- Plan for future needs so that infrastructure will be in place when the need arrives.

Some of these are regional responsibilities. For instance, all PSE facilities that are part of the Bulk Electric System and the interconnected western system must be planned and designed in accordance with the latest applicable and approved version of the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards. These standards set forth performance expectations that affect how the transmission system – 100 kilovolts (kV) and above – is planned, operated and maintained. PSE also must follow Western Electricity Coordinating Council (WECC) reliability criteria; these can be more stringent or more specific than NERC standards at times.

PSE must also ensure that the system is flexible enough to adapt to coming changes. Smart Grid components, electric vehicles, customer distributed resources and demand response programs are some of the effective solutions the industry is moving toward in the future, and we need to be prepared to integrate them for the benefit of our customers.

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1 / Obligations defined by various codes and best practices such as Washington Administrative Code (WAC) 296 - 45 Electric Power Generation, Transmission, and Distribution; WAC 480-90 Gas Companies - Operations; WAC 480-93 Gas Companies - Safety; WAC 480-100 Electric Companies; WAC 480-108 Electric companies - Interconnection with Electric Generators; WAC 480-100-358:398 Part VI Safety and Standard Rules; National Electric Safety Code (NESC) Parts 1, 2 and 3; NERC Reliability Standards; WECC Regional Reliability Standards; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; Washington Industrial Safety and Health Administration; National Electric Code; and Institute of Electrical and Electronics Engineers.

The goal of PSE's planning process is to help us fulfill these responsibilities in the most cost-effective manner possible. Through it, we evaluate system performance and bring issues to the surface; we identify and evaluate possible solutions; and we explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Existing System

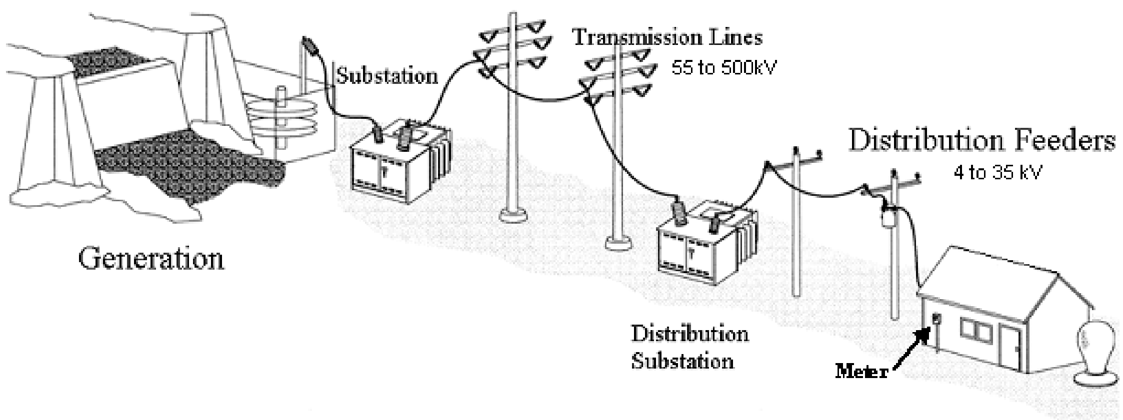
The table below summarizes PSE's existing delivery infrastructure as of December 31, 2016. Electric delivery is accomplished through wires, cables, substations, and transformers. Gas delivery is accomplished by means of pipes and pressure regulating stations.

Figure 8-1: PSE-owned Transmission and Distribution System as of December 31, 2016

ELECTRIC	GAS
Customers: 1,127,002	Customers: 812,723
Service area: 4,500 square miles	Service area: 2,800 square miles
Substations: 352	City gate stations: 40
Miles of transmission line: 2,608	Pressure regulating stations: 581
Miles of overhead distribution line: 10,662	Miles of pipeline: 12,623
Miles of underground distribution line: 10,529	Supply system pressure: 150–550 psig
Transmission line voltage: 55-500 kV	Distribution pipeline pressure: 45-60 psig
Distribution line voltage: 4-34.5 kV	Customer meter pressure: 0.25 psig
Customer site voltage: less than 600 V	

How Electric Delivery Systems Work

Figure 8-2: Illustration of Electric Delivery System

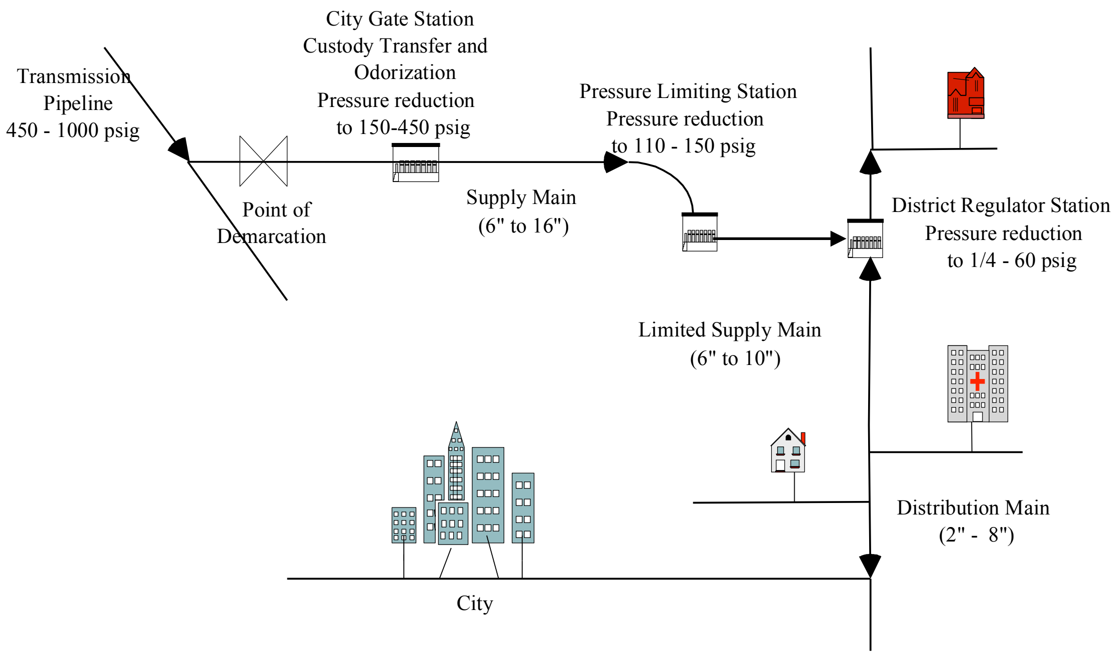


Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 to 500 kilovolts). Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables carry electricity from one place to another. Substations and transformers change voltage to the appropriate level. Circuit breakers prevent overloads, and meters measure how much power is used.

The electric grid was first built 1889, expanding in a highly radial one-way flow design. Over time, the transmission system was looped in a network manner as outages across the nation drove voluntary standards and eventually regulations that require operations with one element out of service. In urban areas a distribution system with looped feeders became common practice to improve reliability. It still operated in a radial one-way flow manner, but as automation and protection devices matured, the system was able to automatically switch to a different source. Nearly 100 percent of the transmission system is networked and portions of PSE's distribution system are looped.

How Natural Gas Delivery Systems Work

Figure 8-3: Illustration of Gas Delivery System



Natural gas is transported at a variety of pressures through pipes of various sizes. Interstate transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge [psig]) to city gate stations. City gate stations reduce pressure to between 150 and 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. From this point the gas flows through a network of piping (mains and services) to a meter set assembly at the customer's site where pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace), and the gas is metered to determine how much is used.

The gas system was first built in the late 1800s, expanding in a network two-way flow design. From its beginnings as a manufactured gas system, the pipeline materials and operating pressures have changed over time. Natural gas was introduced to the area in 1956, allowing for higher pressures and smaller diameter pipes. Where older cast iron pipe was used, new plastic pipe is inserted into it as a way of cost effectively renewing existing infrastructure in urban areas. While the energy qualities and pipeline materials have changed, the technology used to operate the system has not. Now that gas pipelines are often located within increasingly congested rights-of-way, protecting pipelines from damage becomes even more important.

3. WHAT DRIVES INFRASTRUCTURE INVESTMENT?

Even with load growth being offset by PSE conservation efforts, infrastructure expenditures may stay the same or even increase. This is because load growth is only one of the drivers of infrastructure investment. Aging equipment must be maintained or replaced; regulatory requirements may require spending on system upgrades or alterations; public transportation projects can necessitate equipment relocation; and we are required to integrate new generation resources. Below, we describe the six factors that drive infrastructure investment. Some can be known in advance, others can be forecasted, and some circumstances arise from external events such as extreme weather, new codes or policies that drive behavior or actions, or new transportation projects as a result of unexpected increased funding.

Load Growth

PSE's first and foremost obligation is to serve the gas and electric loads of our customers; when customers turn on the switch or turn up the heat, sufficient gas and electricity need to be available. Load drives system investment in three ways as overall system loads, short-term peak loads and point (block) loads must be met.

Overall System Growth

Demands on the overall system increase as the population grows and economic activity increases in our service area, despite the increasing role of demand-side resources and conservation. PSE regularly evaluates economic and population forecasts in order to stay abreast of where and when additional infrastructure, including electric transmission lines, substations and high-pressure gas lines, may be needed to meet growing loads.

Peak Loads

Peak loads occur when the weather is most extreme. To prepare for these events, PSE carefully evaluates system performance during periods of peak loading each year, updates its system models and compares these models against future load and growth forecasts. This prepares us to determine where additional infrastructure investment is required to meet peak firm loads.

Electric and gas system delivery planning is based on near-term and long-term customer growth forecast updates prepared by the Resource Planning and Analysis department. The forecasts include the impact of conservation efforts and implementation of interruptible rate schedules.

Interruptible rate schedules are most commonly employed by commercial or industrial customers due to their ability to provide backup generation for critical load and willingness to tolerate an complete outage for period of time, as PSE must be able to depend on curtailment when needed. Residential customers typically do not tolerate undefined outage lengths during extreme events such as cold weather.

The gas system is designed to operate more conservatively than the electric system because during a peak event the gas system pressure declines as loads increase. As gas pressure approaches zero, customer equipment is unable to operate as intended, requiring manual intervention by PSE to restore service safely. For this reason, gas outages have much greater public and restoration impacts than electric outages and must be avoided for all but the most extreme conditions. The electric system is more flexible. For short periods of time components can often carry more current than their nameplate ratings call for with no adverse effects, and power restoration following an outage can be achieved instantly if power is rerouted through available switches.

Point Loads

System investments are sometimes required to serve specific “point loads” that may appear at a specific geographic location in our service territory. Electrical infrastructure to serve a computer server facility is one example; gas infrastructure to serve an industrial facility such as an asphalt plant is another.

Reliability and Resiliency

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outages, equipment inspection and maintenance records, customer feedback, and PSE field input help identify areas where improvements may be made. Additional consideration is given to system enhancements that will improve resiliency (such as being able to provide a second power line from one substation to another in order to enable a self-healing grid). Some of the investments to improve reliability and resiliency include replacing aging conductors, installing covered conductors (tree wire) and converting overhead lines to underground.

Regulatory Compliance

PSE is committed to operating our system in accordance with all regulatory requirements. The gas and electric delivery systems are highly regulated by several state and federal agencies including PHMSA (Pipeline & Hazardous Materials Safety Administration), NERC, FERC (Federal Energy Regulatory Commission), the WUTC (Washington Utilities and Transportation Commission) and various worker and public safety regulations. Infrastructure investments driven by compliance requirements include electric transmission projects that are aimed at preventing cascading power outages and system collapse that could extend outside PSE's system. Gas regulations drive very specific inspection and maintenance activities and often require the replacement of assets based upon age and/or condition.

Public Improvement Projects

PSE must respond to city, county and state jurisdictions within our service area when transportation-related public improvement projects impact our facilities both within and immediately adjacent to public rights of way. PSE gas and electric facilities may require relocation or underground conversion of electrical facilities to accommodate public transportation projects. We also work closely with local jurisdictions to identify system improvement opportunities and to minimize surface restoration costs and disruptions in association with these public improvement projects.

Aging Infrastructure

With continued maintenance, gas and electric infrastructure can provide safe, reliable service for decades. PSE has a number of programs in place that address aging infrastructure by replacing poles, pipes and other components that are nearing the end of their useful life. Our goal is to maximize the life of the system and at the same time minimize customer interruptions by replacing major infrastructure components prior to significant unplanned failure.

Integration of Resources

FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new generation plant, whether it is owned and operated by PSE or by others, can require significant electric infrastructure investment to integrate and maintain appropriate electrical power flows within our system and across the region. For the gas system, integrating gas supply resources owned and/or operated by PSE or others (such as underground gas storage, on-system LNG/propane-air peak shaving, and the interstate gas transmission systems) can also require significant infrastructure investment to maintain appropriate system pressures and flows across the region.

Distributed generation (DG) – the smaller generation technologies such as roof-top solar panels – must also be reviewed and integrated, often requiring system protection enhancements to satisfy the net metering two-way flow requirements. For larger scale systems, these may also require system infrastructure improvements such as new distribution feeders or a substation.

After initial integration, PSE must monitor the impact and influx of these types of resources in order to address any developing power quality concerns and continue to support the desires of customers. The majority of customers who pursue DG today seek to do more than support their own load and desire to sell excess energy back to the utility, which requires additional consideration of infrastructure reliability. Generally, contributions from this type of generation do not occur during PSE's peak demand[2] necessitating the need for infrastructure to supply peak load in order to deliver reliable service. Storage and control systems to help balance DG limitations are maturing, and as control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to integrate distributed generation more effectively to benefit PSE's operations will increase.

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2 / PSE's peak load occurs in winter when it is dark preventing solar panels from effectively operating during those times.

4. PLANNING PROCESS

The goal of the planning process is to deliver reliable energy in the near term and over the long-term planning horizon in cost-effective ways in order to meet customer needs and maximize value to customers, communities and the company.

PSE's system planning process:

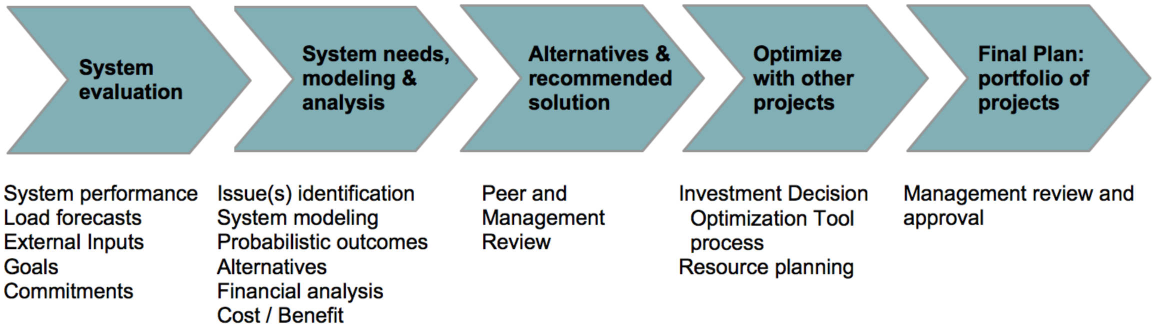
- Takes into account the service quality needs of PSE's customers
- Incorporates all applicable regional and federal orders and rules as they relate to system planning
- Includes industry best practices for planning the system

The planning process begins with an evaluation of the system's current performance and future need through data analysis and modeling tools. Planning considerations include internal inputs such as reliability indices, company goals and commitments, and reviewing the root causes of historic outages. In addition, external inputs such as service quality indices, regulations, municipalities' infrastructure plans, customer complaints and ongoing service issues are also considered. This robust process is lengthy. It starts in the spring and takes 6-8 months from initial research to finalization of the portfolio.

Next, project alternatives are developed. Those alternatives are vetted and reviewed, and projects are compared against one another. Finally, a portfolio of projects is adopted based on optimizing benefit and cost for a given funding level. The process is the same for both long-term and short-term planning. Typically utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

Even after the portfolio for a given year is approved, we continue to monitor changing conditions and make alterations as necessary. This robust process is lengthy. It starts in the spring after storm season when system performance data is available, and takes six to eight months to from initial research to finalization of the portfolio, delivering project scope and resource planning for implementation in the fall of the following year.

Figure 8-4: Delivery System Planning Process



System Evaluation

System evaluation begins with an evaluation of system performance, a review of existing operational challenges, and consideration of load forecasts, demand side management (DSM) and known commitments and obligations. Performance is measured by the system's ability to maintain quality and continuous service during normal and peak loads throughout the year while meeting the regulatory requirements that govern them.

Performance criteria for electric and gas delivery systems lie at the heart of the process and are the foundation of PSE's infrastructure improvement planning.

Figure 8-5: Performance Criteria for Electric and Gas Delivery Systems

Electric delivery system performance criteria are defined by:	Gas delivery system performance criteria are defined by:
Safety and compliance (e.g., 100% compliance)	Safety and compliance (e.g., 100% compliance)
The temperature at which the system is expected to perform (e.g., normal winter peak, extreme winter peak)	The temperature at which the system is expected to perform (e.g., 55 DD Peak Hour)
The nature of service and level of reliability that each type of customer has contracted for (e.g., firm or interruptible)	The nature of service each type of customer has contracted for (e.g., firm or interruptible)
The minimum voltage that must be maintained in the system (e.g., no more than 5% above or below standard voltage)	The minimum pressure that must be maintained in the system (e.g., level at which appliances fail to operate)
The maximum voltage acceptable in the system (e.g., no more than 5% above or below standard voltage)	The maximum pressure acceptable in the system (e.g., defined by CFR 192.623 and WAC-480-93-020)
Thermal limits of equipment utilized to deliver power to load centers and transmission customers (e.g., per PSE Transmission Planning Guidelines)	
The interconnectivity with other utility systems and resulting requirements, including compliance with NERC planning standards (e.g., 100% compliance)	

Performance Inputs

PSE collects system performance information from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), employees and customers. Some information is analyzed over multiple years to normalize the effect of variables like weather that can change significantly from year to year. For near-term load forecasting at the local city, circuit or neighborhood level, we use system peak-load broken down by county and customer growth trends, augmented by permitted construction activity for the next two years and including transmission customer load.

External Inputs

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy or smart grid strategy, are also included in the system evaluation to understand commitments and opportunities to mitigate impact or improve service at least cost. For example, the WUTC issued a policy statement requiring natural gas utilities to file a plan for replacing pipes that represent a higher risk of failure, and PSE's commitment to this plan is considered in the evaluation.

PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As the transportation projects develop through design, engineering and construction, PSE works with the local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs. For aging and risk mitigation infrastructure programs like replacement of all DuPont gas pipe associated with the aforementioned WUTC policy statement or replacement of underground high molecular weight cable, coordination over many years becomes meaningful for all who will be impacted by utility construction and surface restoration requirements.

PSE also meets with jurisdictions in various forums such as quarterly roundtable discussions that include other utilities and agencies and in formal public presentations required through agreement or local regulation in order to gather input about concerns and coordinate solutions. For example, PSE and the City of Bellevue meet annually to exchange plans related to community development and utility system improvements, which provides an opportunity for interested stakeholders to ask questions and raise issues and concerns. Similarly, PSE engages in a multi-year coordination with Bainbridge Island stakeholders to discuss reliability and gather input regarding improvements.

PSE gains public input regarding the need for infrastructure improvement through the PSE and WUTC complaint process, as well as through open forums that result from less than satisfactory service.

System Needs, Modeling and Analysis

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 8-6 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT which then creates the full understanding of all the benefits and risks.

Figure 8-6: Delivery System Planning Tools

TOOL	USE	INPUTS	OUTPUTS
SynerGi®	Gas and Electric network modeling	Gas and electric distribution infrastructure from GIS and load characteristics from CIS, load approvals, load forecast	Predicted system performance
Power World Simulator – Power Flow	Electric network modeling	Electric transmission infrastructure from WECC base case and load/generation characteristics from CIS, load approvals, and load forecast	Predicted system performance
Electric Predictive Spreadsheet	Electric outage predictive analysis	Electric outage history from SAP	Predicted outage savings
Gas Outage Spreadsheet	Gas outage predictive analysis	Gas SynerGi system performance data for future capacity	Predicted outage savings
Estimated Unserved Energy (EUE) Spreadsheet	Electric financial analysis	Estimated project costs; hourly load data from EMS; load growth scenarios from load forecast	Net Present Value; income statement; load growth vs. capacity comparisons; EUE
Distribution / Transmission Integrity Management Risk Assessment	Gas pipeline risk analysis	Gas infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
Asset Management Assessment	Electric maintenance analysis	Electric infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
All data collected by the tools above are input into iDOT			
Investment Decision Optimization Tool (iDOT)	Gas and electric project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document

PSE's gas system model and electric distribution model is a large integrated model of the entire delivery system. It uses a software application (SynerGi® Gas and SynerGi Electric, respectively) that is updated to reflect new customer loads and system and operational changes. This model helps predict capacity constraints and subsequent system performance on a variety of temperatures and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy.

To simulate the performance of the electric transmission system, PSE primarily uses Power World Simulator. This simulation program uses a transmission system model that encompasses infrastructure across 11 western states, 2 provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models are collected, coordinated and distributed through regional organizations including ColumbiaGrid and WECC (one of eight regional reliability organizations under NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards. While PSE utilizes a regional model for system evaluation and coordination, the focus is on local concerns and projects. Appendix I describes regional transmission planning and the role of ColumbiaGrid. ColumbiaGrid has had substantial responsibilities for transmission planning, reliability and other development services since 2006 in order to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. PSE is one of 8 utilities that coordinate regional planning through ColumbiaGrid, which provides transparency and encourages broad participation and interaction with stakeholders, including customers, transmission providers, states and tribes.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system, or in the case of transmission, provided by WECC. For gas, these include the diameter, roughness and length of pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these include conductor cross-sectional area, impedance, length, construction type, connecting equipment, transformer equipment and voltage settings. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system or actual circuit readings. Finally, we take into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

System Alternatives

The alternatives available to address delivery system capacity and reliability issues are listed below. Each has its own costs, benefits, challenges and risks.

Figure 8-7: Alternatives for Addressing Delivery System Capacity and Reliability

ALTERNATIVES	ELECTRIC SYSTEM	GAS SYSTEM
Add energy source	Substation	City-gate station District regulator
Strengthen feed to local area	New conductor Replace conductor	New high pressure main New intermediate pressure main Replace main
Improve existing facility	Substation modification Expanded right-of-way Uprate system Modify automatic switching scheme	Regulation equipment modification Uprate system
Load reduction **Wire/Non-wire**	Rebalance load Fuel switching Distributed energy resource Battery storage Natural gas conversion Conservation/Demand response Load control equipment Possible new tariffs	Fuel switching Conservation Load control equipment Possible new tariffs
Do nothing		

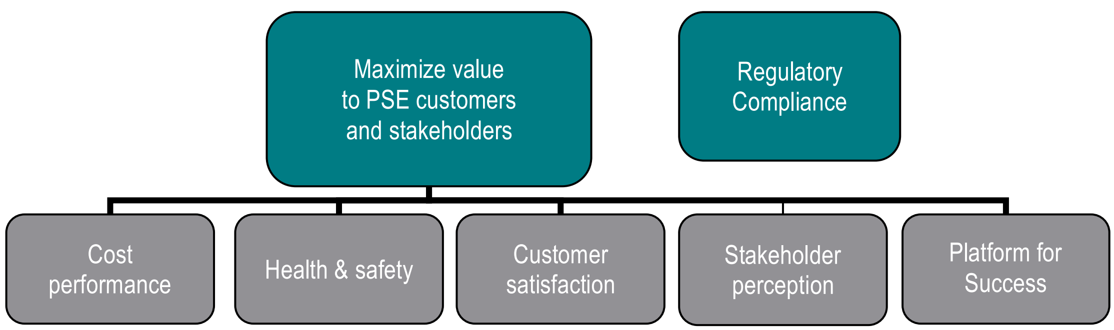
The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

- Temporary adjustment of regulator station operating pressure, as executed through PSE's Cold Weather Action Plan
- Temporary adjustment of substation transformer operating voltage, as done using load tap changers
- Automatic capacitor bank switching to optimize VAR consumption and maintain adequate voltage
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles, liquid natural gas injection vehicles, mobile substations and portable generation

Evaluating Alternatives and Recommended Solutions

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the Investment Decision Optimization Tool (iDOT). To be comparable, alternatives (either singular solutions or a collection of solutions) must solve the need fully. iDOT, as PSE has labeled it, is PriceWaterhouse Cooper's Folio software, a project portfolio optimization and value-based decision analysis tool. iDOT allows us to capture project and program criteria and benefits and score them across thirteen factors, such as meeting required compliance with codes and regulations, net present value of the project, improvement to reliability, safety, future possible customer/load additions, deferral or elimination of future costs, customer satisfaction by eliminating concern, improved external stakeholder perception, and opportunities for future success gained by greater flexibility of the system or gained through learning about new technologies and methods or drivers of specific company objectives. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 8-8: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement, such as pole or meter replacements, are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs. An example is the Pipeline Replacement Program (PRP), developed in response to the Commission Policy Statement on Accelerated Replacement of Pipeline Facilities with Elevated Risk (Docket UG-120715). Particular vintages of wrapped steel and polyethylene facilities are prioritized for replacement based on known risks such as leakage history, pipe condition and the proximity of the pipe to certain structures. Another example is the cable remediation program which prioritizes based on risks such as number of past failures, number of customers impacted and system configuration that prevents timely restoration.

Historically, like many other utilities, PSE has not broadly engaged the public and stakeholders in distribution alternative analysis for several reasons; 1) short timeframes for distribution system planning as a result of solutions needing to be completed within the same or following year; 2) the number of annual projects (generally greater than 400) would be difficult to review effectively; and 3) least cost alternatives are generally apparent to the seasoned expert planning engineer. However, NERC TPL standards define a required stakeholder process that is followed for non-consequential load loss alternatives. PSE recognizes public policy is leading to a desire for greater transparency in how alternatives are selected and will need to determine how to most effectively engage stakeholders based definitions of those policies, guidelines or rulemaking. Criteria or incentives that allow utilities to choose alternatives that are not least cost will be important.

Each recommended project and program is compared using iDOT. This involves building a hierarchy of the value these benefits bring to the stakeholders against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure proper weight and priority is assigned throughout the evaluation process. Using project specific information, iDOT optimizes total value across the entire portfolio of non-mandated or discretionary system infrastructure projects (electric and natural gas) which results in a set of capital projects that provide maximum value to PSE customers and stakeholders relative to given financial constraints. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues such as foreseen permitting or environmental process concerns. Periodically PSE has reviewed this process and the optimization tool along with resulting portfolio with WUTC staff.

Annual plans approved by operations management provide a specific portfolio of projects for the year. Final adjustments may be made as the system portfolio is compared with other objectives of the company such as necessary generator or dam work, or customer initiatives. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (such as public improvement projects that arise or are deferred; changing forecasts of new customer connections; or project delays in permitting) so that we can ensure the total portfolio financial forecast remains within established budget parameters. As plans and projects develop through the design and permitting phases, cost and benefit are routinely evaluated and confirmed before progressing. Alternatives may be reviewed through the project development progress points along with more detailed routing and siting discussions.

The specific portfolio of projects and programs are shared with regional teams and project management teams as project planning begins. Long-range plans are communicated to the public through local jurisdictional tools such as the city and county Comprehensive plans required by the Washington State Growth Management Act. Often this information serves as the starting point for demonstrating the need for improvements to local jurisdictions, residents and businesses far in advance of a project moving to planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.

Public Outreach

In addition to the methods described in the system evaluation section regarding gathering input about need and potential coordination opportunities, PSE engages the community, jurisdictions and stakeholders in various ways to arrive at the specific project that is constructed. Project-specific information provides for the greatest engagement with the public, as it enables the community and stakeholders to see specific impacts or relevant interests based on what it means to them (where the project is and what it improves). Outreach tools include community meetings, routing workshops, public open houses and online open houses, webinars, community mailers, surveys and comment cards.

PSE provides information on pse.com[3] for a wide variety of projects. These include system improvements as well as an overview of the process including public discussion and outreach. The information includes a project overview, what the community can expect during construction, links to project-specific information and contact information for questions and comments. Project-specific webpages for larger and more complex projects provide details and maps. These sites invite stakeholder questions and inquiries.

Depending on the scope and complexity of the project, community advisory groups may be formed to capture the affected area's diverse interests. The goal is to share system needs and potential solutions, to identify and assess community values in the context of the project attributes, and to develop recommendations for PSE's consideration.

As we integrate environmental considerations into project planning, potential effects are identified, assessed, minimized and mitigated as required by all applicable federal, state and local regulatory codes. PSE works with these agencies to obtain all required land use and environmental permits, approvals and authorizations prior to initiation of construction. These permitting processes provide many and various opportunities for written public comment and verbal testimony at open public hearings. Typically, valid and valuable public input is taken into consideration by the agencies and often developed into conditions of final permit approval.

3 / http://pse.com/inyourcommunity/pse-projects/Pages/default.aspx

5. 10-YEAR INFRASTRUCTURE PLANS

PSE develops both short-range and long-range infrastructure plans that support local needs. These are reviewed and validated annually. As the plan year gets closer, the company refines plan projections based on new developments or information and performs additional analyses to reveal and evaluate additional alternatives. The plan may change as a result of these investigations.

The infrastructure additions described below are intended to indicate the scope of investment that may be required over the next ten years in order to serve our customers reliably and fulfill regulatory requirements. They are described in general terms.

Electric Infrastructure Plan

Transmission

In the next decade, PSE anticipates building approximately 104 plus miles of new transmission lines (100 kV and above) and upgrading over 122 miles of existing transmission lines. In addition, we anticipate needing to add up to three 230 kV bulk power substations across our service area. These planned improvements do not include transmission needed to support the broader region or improvements needed as a result of providing interconnections for large generation resources. As a "Transmission Provider," PSE must process all transmission interconnection requests according to applicable FERC resource interconnection procedures. NERC TPL standards establish transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.[4] These requirements are a primary driver of transmission projects.

Distribution

In the next decade, PSE anticipates the need to build approximately 6 to 8 new distribution substations to serve load as existing substation capacity is exceeded and another 2 to 4 new substations to serve specific point loads. We also anticipate upgrading approximately 3 existing substations to replace aging infrastructure and adding additional capacity to serve local load growth. In total, the new or expanded substations will require 32 to 48 new distribution lines. PSE will continue work on improving reliability of its worst performing circuits as well as installing smart ready equipment for increasing the resiliency of the grid.

4 / http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission System Planning Performance Requirements&jurisdiction=United States

Ongoing Maintenance

Based upon current projections and past experience, in the next decade PSE expects to replace 1,800 miles of underground high molecular weight, failure-prone distribution cable, approximately 1,000 transmission and 10,000 distribution poles. Additionally, PSE anticipates replacement of several major substation components as a result of ongoing inspection and diagnostics. PSE anticipates replacement of its current aging and obsolete Automated Meter Reading (AMR) communication system as well as its electric customer meters with Advanced Metering Infrastructure (AMI) technology to enable smart grid enhancements and customer offerings in the future.

Figure 8-9: Summary of 10-Year Electric Infrastructure Plan

ASSET	NUMBER	LOCATION
New Transmission Lines	104 miles	System-wide
Upgraded Transmission Lines	122 miles	System-wide
New Bulk Power Substations	Up to three	System-wide
New Distribution Substations	Eight to Twelve	System-wide
Upgraded Distribution Substations	Three	System-wide
Distribution Lines	32 to 48	System-wide
Cable Replaced	1,800 miles	System-wide
Transmission Poles Replaced	1,000	System-wide
Distribution Poles Replaced	Up to 10,000	System-wide

Planned Transmission System Improvements

PSE participates in coordinated, open, and transparent transmission planning processes as intended by FERC Order 1000 and outlined through the western regional planning processes of ColumbiaGrid. PSE identifies new transmission facilities and facility replacements or upgrades required to meet system needs over the ensuing ten years. This list of projects is documented pursuant to PSE's Attachment K as a participant of those processes.[5] Transmission planning studies are performed and project requirements are updated annually. Appendix I: Regional Transmission provides more information regarding Order 1000 and Attachment K.

The following list is based on the 2016 planning results[6] and provides a high-level description of scope of work, a footnote where more information can be found, and estimated date of completion. It is important to remember that these projects are not associated with facilitating generation resource paths, but are required to meet the local growth or reliability needs of PSE's customers, which may impact the interconnected grid.

5 / http://www.oatioasis.com/PSEI/PSEIdocs/Attachment_K_20160401.pdf
6 / http://www.oatioasis.com/PSEI/PSEIdocs/PSE_Plan_2016_Draft.pdf

PROJECTS COMPLETED SINCE LAST 2015 IRP. (Information on a variety of completed projects with in the last six months can be found on PSE's website at https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Completed-improvements.aspx.) The format of this list of projects is intended to follow Attachment K as closely as possible in order to avoid inconsistency or confusion. The purpose is generally described in terms of improving reliability, increasing capacity to serve load growth, or meeting NERC TPL standards and the planning requirements relative to operating contingencies.

1. **Blumaer – Yelm 115 kV Re-conductor**[7]
   Date of Operation: 2016
   This project addressed *capacity* and *reliability* needs of the Yelm area by rebuilding the remaining 12-mile Blumaer – Yelm section of the 42-mile Blumaer – Electron Heights 115 kV transmission line, which mostly consists of 4/0 Cu and 336 ACSR conductors, to 115 kV Standard 1272 ACSR 100C conductor.

2. **Spurgeon Creek Transmission Substation Development (Phase 1)**[8]
   Date of Operation: 2016
   In Phase 1, this project addressed *reliability* of transmission service to the cities of Lacey, Olympia and Tumwater, by looping the Blumaer – St Clair 115 kV transmission line into the new Spurgeon Creek substation. This project looped the Olympia – St Clair #1 115 kV line into Spurgeon Creek.

3. **Moorlands – Vitulli 115 kV Rebuild**[9]
   Date of Operation: 2017
   This project addressed *capacity* and *reliability* needs in the Kenmore and Bothell areas and NERC planning standards requirements by rebuilding the line to increase the winter emergency line rating from 122 MVA to 249 MVA.

FUTURE PROJECTS

4. **Bellingham 115 kV Substation Rebuild**
   Estimated Date of Operation: 2019
   This project will increase system *reliability* in Whatcom County. It involves replacing the existing aging 115 kV main bus substation with a new breaker and a half 115 kV substation.

7 / https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Yelm-area-reliability.aspx
8 / https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Spurgeon-Creek-substation.aspx
9 / https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Moorlands-Vitulli-115-kV-transmission-line-upgrade.aspx

5. **Sedro Woolley – Bellingham #4 115 kV Rebuild and Reconductor**
   Estimated Date of Operation: 2021
   This project will increase *capacity* and *reliability* between Whatcom and Skagit Counties by rebuilding the 24-mile long Bellingham – Sedro #4 115 kV line and installing higher capacity conductors.

6. **Lake Hills – Phantom Lake New 115 kV Line**[10]
   Estimated Date of Operation: 2017
   This project will improve *reliability*, which involves building a new line from Lake Hills to Phantom Lake. This line is necessary to eliminate a radial-only feed to two existing substations such that they can be served during outage conditions.

7. **Sammamish – Juanita New 115 kV Line**[11]
   Estimated Date of Operation: 2017+
   This project will increase *capacity* and address *NERC planning standards requirements* by building a new line from Sammamish to Juanita with 1272 kcmil Bittern at 100° C.

8. **Novelty – Stillwater – Cottage Brook 115 kV Rebuild**
   Estimated Date of Operation: 2018
   This project will increase *capacity* and address *NERC planning standards requirements* by rebuilding the line from 2/0 copper conductors to 1272 kcmil Bittern at 100° C.

9. **Talbot 230 kV Bus Improvements**
   Estimated Date of Operation: 2018+
   This project will improve *reliability* through continuity of service during maintenance work and substation outages by constructing bus improvements on the north and south 230 kV buses at Talbot.

10 / *https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Lake-Hills-Phantom-Lake.aspx*
11 / *https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Sammamish-Juanita.aspx*

10. **Eastside 230 kV Transformer Addition and Sammamish – Lakeside – Talbot 115 kV Rebuilds (the Energize Eastside Transmission Capacity Project)**[12]
Estimated Date of Operation: 2018+
These projects are intended to provide additional *capacity* to serve the projected load growth in north central King County, to reinforce the existing transmission ties between north King and central King areas, and to address *NERC planning standards requirements*. This involves the addition of a 230 kV/115 kV transformer substation in the center of the Eastside load area, and rebuilding the 115 kV Sammamish – Lakeside – Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth. A detailed description of this project is presented in the next section of this chapter.

11. **Electron Heights – Enumclaw 55-115 kV Conversion**
Estimated Date of Operation: 2019
This project provides *capacity* and better *reliability* in southeast King county and east Pierce county and also addresses *NERC planning standard requirements* by converting an existing 55 kV transmission line and associated substations to 115 kV operation.

12. **Brisco Park Substation and O'Brien – Brisco 115 kV Transmission Line**
Estimated Date of Operation: 2019+
This project will provide needed *capacity* and better *reliability* to support the existing and expected load growth in this commercial/industrial area by providing a new 115 kV transmission line in Kent and a new 6-breaker 115 kV ring bus substation in Tukwila.

13. **Spurgeon Creek Transmission Substation Development (Phase 2)**
Estimated Date of Operation: 2020
In Phase 2, this project will improve the *reliability* of transmission service to the cities of Lacey, Olympia and Tumwater by looping the future transmission tap extension from Olympia via the Airport substation to Spurgeon Creek. This project also loops in the Olympia – St Clair #1 115 kV line into Spurgeon Creek.

14. **White River – Electron Heights 115 kV Line Re-route to Alderton (Phase 2)**
Estimated Date of Operation: 2017-18
This project will improve the *reliability* of transmission service to the cities of Bonny Lake, Orting and surrounding areas where major housing developments are to be built by looping the White River – Electron Heights three-terminal 115 kV transmission line into Alderton.

12 / *https://www.energizeeastside.com*

15. Pierce County Transformer Addition

Estimated Date of Operation: 2017-18

This project is intended to provide additional *capacity* to serve the projected load growth in Pierce County and surrounding areas. The project will involve installation of a 230-115 kV transformer at Alderton substation and about 8 miles of 230 kV transmission line from White River to Alderton.

16. Woodland – St. Clair 115 kV (Phase 2)

Estimated Date of Operation: 2021+

This project will increase the transmission intertie capability and *reliability* between Pierce and Thurston counties by adding a third transmission intertie between Pierce and Thurston Counties with construction of the remaining 8 miles 115 kV line between Gravelly Lake and Woodland substations.

17. Alderton – Woodland 115 kV uprate

Estimated Date of Operation: 2021+

This project will increase *capacity* in the Pierce County area by uprating the Alderton – Woodland section of the White River – Fairchild – Alderton 115 kV transmission line, which consists of about 6 miles of 795 TERN 55C conductor. The line section will be uprated to 100C. This project is planned to be completed concurrent with the Woodland – St Clair Phase 2 project.

18. White River 115 kV Bus Improvement

Estimated Date of Operation: 2021+

This project improves *reliability* by reconfiguring the White River 115 kV main bus to multiple bus sections to reduce the number of line bay forced outages for a bus fault or 115 kV breaker failure condition.

19. West Kitsap Transmission Project

Estimated Date of Operation: 2020+

This project is intended to provide additional *capacity* to serve the projected load growth in Kitsap County and improve transmission reliability for customers in central and north Kitsap County. The project is planned to be staged in phases over time and will involve construction of multiple segments of 115 kV transmission lines between BPA Kitsap/South Bremerton to Valley Junction. The final step of the multi-year plan is to add a 230-115 kV transformer capacity in Kitsap County.

Areas of Future Focus

PSE will continue to improve the electric system planning process as more data regarding demand and conservation potential becomes available with technologies such as AMI (Advanced Metering Infrastructure). Additionally, as technologies mature and PSE's grid becomes more modern, alternatives will be refreshed and reevaluated when necessary. Due to the complexity of the larger planned transmission system improvement projects, the first gate of project development known as Initiation will refine the need and reconfirm preliminary alternatives and solutions and consider implementation challenges and new information. This process targets needs that are more than four to five years out in order to provide adequate review and engagement. This process will improve as PSE matures its ability to predict localized circuit-level load growth and conservation potential. Additionally, the incorporation of learnings about alternative technologies and applications will be important as well.

Energize Eastside Transmission Capacity Project

To illustrate the evaluation, analysis and community involvement PSE performs in the process of making system improvement decisions, PSE is including a detailed description of the Energize Eastside Transmission Capacity Project (project #10 above) in this chapter of the IRP.

The Energize Eastside project is needed to meet the local growth needs of the east side of King County, including Bellevue, Redmond, Kirkland, Renton, Newcastle and Issaquah. The following pages discuss the identification of need, the analysis of alternatives considered to address need and the engagement of the Eastside community in a robust public process. The needs assessment and solution identification phases of this project have been completed. Currently, the project is in the route selection and permitting phases.

Project Background

Electricity is currently delivered to the Eastside area[13] through two 230 kV/115 kV bulk electric substations – the Sammamish substation in Redmond and the Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using 115 kV transmission lines. PSE has made many system improvements in the Eastside area over the years, but the primary 115 kV lines that connect the Sammamish and Talbot Hill substations (which are the backbone of the Eastside electrical system) have not been upgraded since the 1960s. Since then, the Eastside population has grown from approximately 50,000 to nearly 400,000. This growth is expected to continue. The Puget Sound Regional Council (PSRC) is a regional planning agency with specific responsibilities under federal and state law for transportation planning, economic development and growth management. PSRC is a leading source of data and forecasting that is essential for regional and local planning. PSE has been tracking PSRC's data releases since the project was launched in December 2013, and updated project materials with the new data in July 2014. PSE has specifically used PSRC's Land Use Baseline growth projections, which model population and employment growth in the Puget Sound region. Projections by the PSRC show the Eastside population will likely grow by another third and employment will grow by more than three-quarters over the next 25 years.

13 / For the purpose of this project, the Eastside is defined as the area between Renton and Redmond, bounded by Lake Washington to the west and Lake Sammamish to the east.

As required by federal regulations, PSE performs annual comprehensive electric transmission planning studies to determine if there are potential system performance violations (transformer and line overloads) under various operational scenarios and forecasted electrical use. The need for additional 230kV support for the Eastside area was identified and has been included in PSE comprehensive plans since 1993.

During the 2009 comprehensive reliability assessment, PSE determined that there was a transmission reliability supply need developing due to the loss of one of the Talbot Hill Substation transformers. Since 2009, other issues have also been identified which impact this portion of the PSE system. These issues include concerns over the projected future loading on the Talbot Hill Substation and increasing use of Corrective Action Plans (CAPs)[14] to manage outage risks to customers in this portion of the PSE system.

PSE performed studies in 2013 and 2015 that revealed it could not meet federal reliability requirements by the winter of 2017/2018 and the summer of 2018 without the addition of 230 kV to 115 kV transformer capacity in the Eastside area. (Links to these studies are provided on page 30.)

To respond to the deficiencies identified in the transmission planning studies, PSE has proposed to construct and operate a new 230 kV to 115 kV electrical transformer served by approximately 18 miles of new high-capacity electric transmission lines (230 kV) extending from Renton to Redmond; this plan includes continued aggressive conservation measures. The proposed transformer will be placed at a substation site near the center of the Eastside.

Electrical power transmitted to the new substation for distribution to local customers will address a deficiency in electrical transmission capacity during peak periods identified by PSE through its system planning process. PSE's Eastside system currently experiences peak demand during the winter driven by heating loads; the summer peak is driven by cooling loads. Continuing population growth increases the risk of more severe overloading by summer 2018. To address this risk, PSE launched the Energize Eastside project in December 2013.

14 / See page 8-38 for description of a Corrective Action Plan.

Regulatory Requirements

The performance requirements of any integrated transmission system are heavily regulated at both the federal and regional levels. PSE's regulators include FERC, NERC and WECC (the Federal Energy Regulatory Commission, North American Electric Reliability Corporation and Western Electricity Coordinating Council, respectively).

NERC is the regulatory authority certified by FERC to develop and enforce reliability standards. NERC has delegated the task of monitoring and enforcing the federal reliability standards to WECC, the regional entity that has authority over transmission in the western region.

The NERC standards mandate that certain forecasts and studies must be completed to determine if the system has sufficient capability to meet expected loads now and in the future. When completing transmission planning studies, contingencies are simulated to determine if the electric system meets the mandatory NERC performance requirements[15] for a given set of forecasted demand levels, generation configurations and levels, and multiple system component outages.

Even if these outage scenarios are unlikely, federal regulations require that the appropriate planning be performed proactively. This conservative planning methodology is implemented to prevent large scale, cascading, transmission system blackouts, like those that have occurred in the recent past (for example, the 2003 Northeast blackout that affected 55 million people in the Northeast and Midwest regions of the United States and Canada).

The PSE transmission planning studies performed in 2013 and 2015 determined that thermal violations on transmission line and transformer equipment might occur under foreseeable scenarios within the next few years. The thermal violations are a result of running scenarios for several component outage contingencies, as required by NERC, that take into consideration peak demand (which is heavily dependent on seasonal temperatures and daily demand profiles) and levels of conservation. In essence, this is a requirement to have redundancy in the transmission system.

15 / The NERC transmission planning standards (TPL) that were in effect in 2012-2013 were: TPL-001-3, TPL-002-0b 2nd Rev (TPL-002-2b), TPL-003-0b 2nd Rev (TPL-003-2b), and TPL-004-2. TPL-001-3, TPL-002-2b, TPL-003-2b, and TPL-004-2 are being retired as they are replaced in their entirety by TPL-001-4. Enforcement of the new standards began January 1, 2015. Visit the NERC website at http://www.nerc.com/pa/Stand/Reliability Standards/TPL-001-4.pdf for more information. Note: Compliance is mandatory irrespective of stakeholders willingness to accept greater reliability risk. See U.S. - Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004.

Needs Assessment Reports

In total, five separate studies performed by four separate parties have confirmed the need to address Eastside transmission capacity:

- **Electrical Reliability Study by Exponent, 2012 – City of Bellevue**
  http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/final_electrical_reliability_study_phase_ii_report_2012.pdf
- **Eastside Needs Assessment Report by Quanta Services, 2013 – PSE**
  https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf
- **Supplemental Eastside Needs Assessment Report by Quanta Services, 2015 – PSE**
  https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf
- **Independent Technical Analysis by Utility Systems Efficiencies, Inc., 2015 – City of Bellevue**
  http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/cob_independent_technical_analysis_1-3.pdf
- **Review Memo by Stantec Consulting Services Inc.**, 2015 – EIS consultant
  http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/stantec_review_memo_eastside_needs_assessment_report.pdf

PSE NEEDS ASSESSMENT REPORTS, 2013[16] AND 2015.[17] PSE transmission planning studies demonstrate that, under certain contingencies, the delivery system on the Eastside could not continue to meet reliability requirements without significant infrastructure upgrades.

The Needs Assessment reports published in 2013 and 2015, which PSE performed pursuant to the mandatory federal transmission planning standards, identified four major areas of concern.

1. ***Overload of PSE facilities in the Eastside area.*** Studies identified potential overloading of transformers at Sammamish and Talbot Hill substations, and several 115 kV transmission lines routing power to the Eastside area are at risk of overloading under certain conditions.

2. ***Small margin of error to manage risks from inherent load forecast uncertainties****.* PSE's planning studies rely in large part on load forecast data. Imbedded in PSE's load forecasts are several factors that include elements of risk. These include conservation, weather and block loads.

16 / A link to the 2013 report is provided above.
17 / A link to the 2015 report is provided above.

- Conservation: To date, PSE customers have achieved 100 percent of the company's conservation goals, which are very aggressive according to industry experts. If 100 percent of conservation goals are not achieved, then the transmission system capacity will be surpassed sooner than expected. [18]
- Weather: PSE's load forecast assumes "every other year" cold weather. (Some utilities take a more conservative approach, using the coldest and hottest weather in five or ten years, as inputs to system performance studies.[19]) If the region experiences weather extremes outside of those used in PSE's planning studies, electricity demand will surpass the transmission system capacity sooner than expected.
- Block loads: These include large development projects that add significant load to the system. If block load growth increases more than anticipated, demand for electricity will surpass the transmission capacity sooner than expected.

3. ***Increased use and expansion of Corrective Action Plans (CAPs) to keep the system compliant***. CAPs are a series of operational steps used to prevent system overloads or loss of customers' power. They are a short-term fix to alleviate potential operational conditions that could put the entire grid at risk. They protect against large-scale, cascading power outages; however, they can put large numbers of customers at increased risk of power outages. For example, to prevent winter overloads on the Talbot Hill transformer banks, PSE is already using CAPs, which increases outage risk to customers. As growth continues, additional CAPs will be needed. By Federal standards, CAPs are not intended to be long-term solutions to system deficiencies.

4. ***Impacts to interconnections identified by ColumbiaGrid.*** Though the need for Energize Eastside is driven by local demand, because the electric system is interconnected for the benefit of all, it is a federal requirement to study all electric transmission projects to ensure there are no material adverse impacts to the reliability or operating characteristics of PSE's or any surrounding utilities' electric systems. ColumbiaGrid, the regional planning entity, produces a Biennial Transmission Expansion Plan that addresses system needs in the Pacific Northwest, including the PSE system.

18 / PSE tested the conservation goals at 100%, 75%, 50%, and 0%. See the 2013 and 2015 Eastside Needs Assessment reports.
19 / For example ISO-NE have plans to a 90/10 or one in ten-year weather forecast.

PSE's 2015 Supplemental Needs Assessment Report confirmed the winter deficit findings in the 2013 Needs Assessment Report, stating that:

> By winter of 2017-18, there is a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, Newcastle, and Renton along with Clyde Hill, Medina, and Mercer Island... ***By winter of 2019-20, at an Eastside load level of approximately 706 MW, additional CAPs are required that will put approximately 63,200 Eastside customers at risk of outages.***

The 2015 Needs Assessment also confirmed that by summer of 2018, there would be a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Renton, Bellevue, Issaquah and Newcastle along with Clyde Hill, Medina and Mercer Island. ***By summer of 2018, CAPs will be required to manage overloads under certain multiple contingencies, and the use of these CAPs will place approximately 68,800 customers at risk and could require 74 MW of load shedding, affecting approximately 10,900 customers at a time.***

Based on the 2015 Needs Assessment, if the Energize Eastside project gets delayed until after the summer of 2018, load shedding may be used as a corrective action plan to meet the mandatory reliability requirements defined by NERC. This could result in PSE having to turn the power off to tens of thousands of customers under certain forecasted conditions and would be necessary to prevent more widespread outages beyond the Eastside area. To further study this, in 2015 PSE commissioned Nexant to simulate three scenarios of rotating outages that could be needed if no action is taken to upgrade the Eastside's transmission system. Nexant's Energize Eastside Outage Cost Study determined that if PSE must use corrective action plans that include rolling blackouts, more than 130,000 customers could be impacted as early as the summer of 2018, at a cost of tens of millions of dollars to the local economy.

Load shedding is not a practice that PSE or many other responsible utilities use unless absolutely necessary. Since load shedding adversely impacts residential, commercial and industrial customers, and surrounding cities, towns and neighboring communities, it is necessary and good utility practice to coordinate with cities, towns, municipal officials and emergency services, and to publicly inform those affected.

CITY OF BELLEVUE-COMMISSIONED INDEPENDENT TECHNICAL ANALYSIS.[20] The City of Bellevue contracted with Utility System Efficiencies, Inc. (USE) to perform an independent technical analysis (ITA) of the purpose, need and timing of the Energize Eastside project, and this study confirmed the capacity deficiency in the Eastside area.

This independent analysis concluded that PSE followed industry practice in forecasting its demand load, incorporating the four major components of forecasting:

- PSE incorporated weather normalizing. The variables used in the weather normalization process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for its economic/demographic data, acquiring data at the county level, and for the Eastside area at the census-tract level, in order to differentiate growth rates within the service territory. Data on jobs and employment in the Eastside region were obtained by PSE from the Puget Sound Regional Council (PSRC) and the Washington State Office of Financial Management, and included census-tract-level analysis.
- PSE employed regression analysis at this step, an industry standard computer analysis technique, to determine the forecast before new conservation measures and block load adjustments.
- PSE acquired and developed significant end-user data via its IRP process. This includes over 4,000 Demand Side Resource (DSR) measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100 percent conservation scenario which projects 135 MW of winter peak DSR by 2031. PSE gathered block load data and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp out) to account for the impact on demand.

The ITA concluded that “PSE used reasonable methods to develop its forecast showing the Eastside area growing at a higher level [faster pace] than the county or system level.”

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20 / A link to the City of Bellevue ITA is provided on page 30.

In addition, the ITA addressed common questions about the project, including:

- Is the Energize Eastside project needed to address the reliability of the electric grid on the Eastside? ***The ITA determined, "YES."***
- If the load growth rate was reduced, would the project still be needed? ***The ITA determined, "YES."***
- If generation was increased in the Puget Sound area, would the project still be needed? ***The ITA determined, "YES."***
- Is there a need for the project to address regional flows, with imports/exports to Canada (ColumbiaGrid)? ***The ITA determined that by modeling zero flow to Canada, the project is still necessary to address local need***.

SEPA ANALYSIS AND PROJECT NEED. In addition to the needs analyses described above, Energize Eastside's environmental reviews also involved needs analyses. For example, during development of the State Environmental Policy Act (SEPA) Draft Environmental Impact Statement (EIS), a review memo summarized the EIS team subcontractor's independent analysis of project need:

> "...PSE['s] needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE's system on the Eastside that requires attention in the near future." – DeClerck, Review Memo by Stantec Consulting Services Inc., July 31, 2015.[21]

21 / *A link to the Stantec memo is provided on page 30.*

FERC FINDINGS AND CONCLUSION. In response to a complaint filed with the Federal Energy Regulatory Commission against PSE and others, specific to Energize Eastside, FERC dismissed the complaint, stating*:*

> Based on the record before us, we find that Puget Sound [PSE] and the other Respondents complied with their transmission planning responsibilities under Order No. 890 in proposing and evaluating the Energize Eastside Project. – FERC Docket No. EL15-74-000, *Order Dismissing Complaint*, Issued Oct. 21, 2015.[22]

The FERC response also concluded:

> We agree with Puget Sound [PSE] and ColumbiaGrid that the Energize Eastside Project was properly classified a Single System Project because it was designed to address Puget Sound's projected inability to serve its own customers, ColumbiaGrid's Puget Sound Area Study Team did not find any Material Adverse Impacts associated with the project, and ColumbiaGrid included the project as a Single System Project in its most recent 2015 Biennial Plan. Accordingly, we find that the Energize Eastside Project was proposed and evaluated in accordance with the then-applicable transmission planning requirements. – FERC Docket No. EL15-74-000, *Order Dismissing Complaint*, Issued Oct. 21, 2015.[23]

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22 / https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/2015_1021_FERC_OrderDismissingComplaint.pdf
23 / Ibid

Requirements for Solutions to Meet Need

Any solution to solve this deficiency must meet all NERC performance criteria, address all relevant PSE equipment overloads, and continue to meet the performance criteria for ***at least 10 years*** after construction. To define the solution, PSE developed criteria to evaluate potential solutions. The following excerpt is from Section 2.5.1 of the 2015 Solutions Study.

ELECTRICAL PERFORMANCE CRITERIA

a. Must meet all performance criteria:
   - Applicable transmission planning standards and guidelines, including mandatory NERC and WECC standards (NERC TPL-001-4 and WECC TPL-001-WECC-CRT-2)
   - Within study period (2015– 2024)
   - Less than or equal to 95 percent of emergency limits for lines
   - Less than or equal to 90 percent emergency limit for transformers
   - Normal winter load forecast with [both] 100 percent and 75 percent conservation
   - Normal summer load forecast with 100 percent conservation
   - Adjust regional flows and generation to stress cases similar to annual transmission planning assessment
   - Take into account future transmission system improvement projects that are expected to be in service within the study period
   - Minimal or no re-dispatching of generation[24]
   - No load shedding
   - No new Remedial Action Schemes
   - No Corrective Action Plans

b. Must address all relevant PSE equipment violations

c. Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems

d. Must meet performance criteria listed above for 10 or more years after construction with up to 100 percent of the emergency limit for lines or transformers.

24 / *See the Eastside Needs Assessment Report (October 2013)*

Alternatives Considered

PSE studied a variety of potential solutions to resolve the Eastside transmission deficiencies; these included additional conservation, additional generation, demand response (DR), distributed generation (DG), energy storage, expansion of transmission substations, transmission line upgrades and new transmission lines. The results of these studies are documented in PSE's Solutions Report (2014)[25] and Supplemental Eastside Solutions Study Report (2015).[26]

Ultimately, the 2015 Solutions Study verified the findings of the 2014 Solutions Report, that the preferred solution to solve the Eastside's transmission deficiencies was aggressive conservation combined with construction of a new 230/115 kV transformer and 230 kV line with associated ancillary facilities.

The alternatives studied are summarized in Figure 8-10, and discussed in more detail in the following pages.

Figure 8-10 Summary of Alternatives and Technologies Studied

ALTERNATIVE STUDIED	MEETS CRITERIA	STUDIES AND REPORTS (Authors)
1. Additional conservation within the Eastside Area	NO	2015 Solutions Study (PSE) Non-wires Alternatives Screening Study (E3)
2. Additional generation within the Eastside Area	NO	2015 Solutions Study (PSE)
3. Energy storage	NO	2015 Solutions Study (PSE) Eastside System Energy Storage Alternatives Screening Study (Strategen)
4. Transmission line reinforcements and transformer additions	YES	2015 Solutions Study (PSE)
5. Combination of solutions	NO	2015 Solutions Study (PSE)

25 / https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports /TransmissionSolutionStudyFebruary2014REDACTEDv2.pdf
26 / https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/ SupplementalSolutionsReport_Redacted_May2015.pdf

ALTERNATIVE 1 – ADDITIONAL CONSERVATION. PSE retained Energy and Environmental Economics, Inc. (E3) in 2014 to conduct a Non-wires Alternatives Screening Study.[27] E3 included energy efficiency, demand response and distributed generation measures in its evaluation of cost-effective non-wires potential in the Eastside area. The study concluded that the cost-effective non-wires potential for the Eastside is not large enough to provide sufficient load reduction to allow even a 4-year deferral of Eastside transmission upgrade needs.

The amount of additional conservation in the Eastside area required to avoid transmission upgrades ranged from a low of 138 MW to a high of 244 MW.[28] The minimum conservation level of 138 MW was in addition to achieving 100 percent of the projected conservation for the entire PSE system (424 MW from the 2014 Load Forecast); the high level of 244 MW was in addition to achieving 75 percent of the projected conservation for the entire PSE system (318 MW from the 2014 Load Forecast).

The study determined that the non-wires potential in the area, including energy efficiency, demand response and distributed generation measures did not represent a permanent solution to the need for the transmission upgrade options, nor was it sufficiently cost-effective to defer the need date for transmission upgrades while maintaining equivalent reliability levels. For more detail see the full report.

27 / https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/PSEScreeningStudyFebruary2014.pdf

28 / A 70 MW to 140 MW range was identified in the 2014 Solution Study. This level was sufficient to drop below 100 percent of the Talbot Hill transformer rating in winter of 2017/18. However, a valid solution requires a transformer loading of no more than 90 percent. Therefore, the 2015 Solution Study identified a higher level of conservation, which was sufficient to drop the loading level on the Talbot Hill transformers down to 90 percent under the worst contingency.

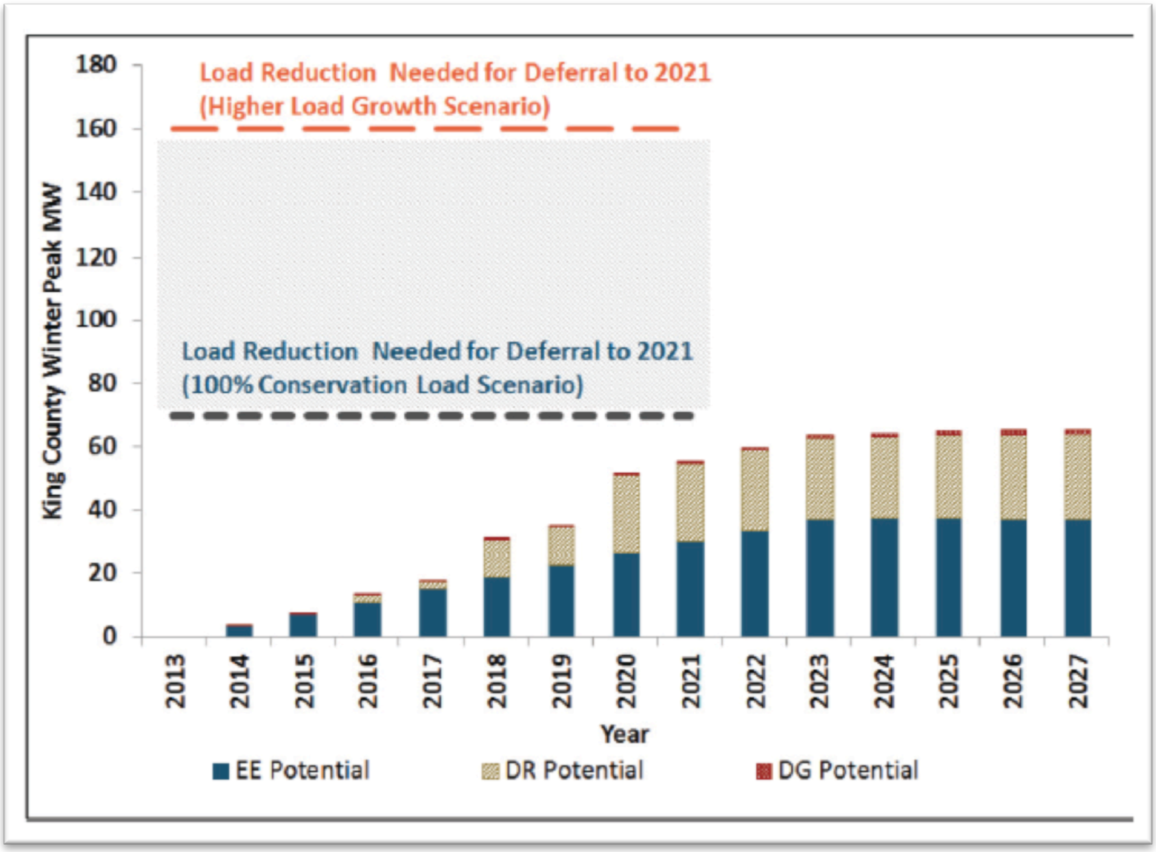
E3's valuation of deferral savings for the project is detailed in this excerpt from its report.

The results of this savings calculation are shown in the table below. If the transmission upgrades could be deferred from the planned online date of Winter 2017 to Winter 2021, this four year deferral would create total present value savings for PSE ratepayers of $40.24 million in transmission project costs. Assuming that PSE would require 70 MW of incremental load reduction to enable a four-year project deferral, this savings is equivalent to a capacity payment of $575/kW for the four-year period, or annual savings of $155/kW-year.

Table 3: Transmission Revenue Requirement Savings of Deferring Eastside Transmission Upgrades

	Winter 2021
Transmission Revenue Requirement Savings ($ million)	$40.24
$/kW (contracted)	$575
$/kW-year (levelized)	$155

Figure 8-11: King County Non-wires Potential vs. Reduction for Needed Deferral



ALTERNATIVE 2 – ADDITIONAL GENERATION WITHIN EASTSIDE. PSE studied both conventional generation and distributed generation (DG) in its 2015 Solutions Study. To be effective, this alternative would require at least 300 MW of generation located in the Eastside area. Locating conventional generation of this size on the Eastside has major siting and environmental challenges. For DG to meaningfully impact the identified needs, DG must be installed in the right locations, available when needed and be of significant magnitude. Locating 300 MW or more of distributed renewable generation within the Eastside area by the winter of 2017/2018 was not practical. See the Supplemental Eastside Solutions Study reports (2014 and 2015) for more detail.

ALTERNATIVE 3 - ENERGY STORAGE. PSE contracted with Strategen in 2015 to perform an Eastside System Energy Storage Alternatives Screening Study,[29] which concluded that an energy storage system with power and energy storage ratings comparable to PSE's identified need has not yet been installed anywhere in the world. In addition, Strategen determined that the existing Eastside transmission system does not have sufficient capacity to charge energy storage systems to a level sufficient to meet PSE's operating standards.

Based on the interconnection, permitting, procurement and construction timelines provided by PSE, project development for any energy storage configuration would take approximately four years, resulting in a mid-2019 online date. Private developers who are able to take on more project risk may be able to accelerate this cycle by approximately one year.

29 / *http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/eastside_system_energy_storage_alternatives_screening_study_march_2015.pdf*

Strategen evaluated a baseline configuration and two alternatives that also included non-wires measures.

- Strategen estimated that the Baseline Configuration to defer the Eastside transmission system upgrade through 2021 would cost ratepayers approximately $1.44 billion in net present value (NPV) terms, based on PSE's revenue requirement; however, the Baseline configuration is not technically feasible.
- Alternate Configuration #1 would cost ratepayers approximately $264 million in NPV terms, based on PSE's revenue requirement. Cost-effectiveness value was derived primarily from the system capacity, flexibility and oversupply reduction benefits for PSE's customers. (Carbon emission reduction is another benefit, but it is currently non-monetizable.) With a benefit-cost ratio of approximately 1.13, this configuration does appear to be cost-effective, but it does not meet the reliability requirements for the solution.[30]

Neither Alternative #1 nor Alternative #2 appears capable of meeting PSE's target online date of 2017/2018. The cost-benefit ratio for the Baseline and Alternative #2 were not calculated because they were not technically feasible. Figure 8-12 presents the capital cost estimates from the E3 report. See the 2014 PSE Screening Study by E3 for details.

30 / Per the 2015 Strategen report, "The Baseline Configuration (a 328 MW / 2,338 MWh storage system) is not technically feasible because the existing Eastside transmission system does not have sufficient capacity to fully charge the system."

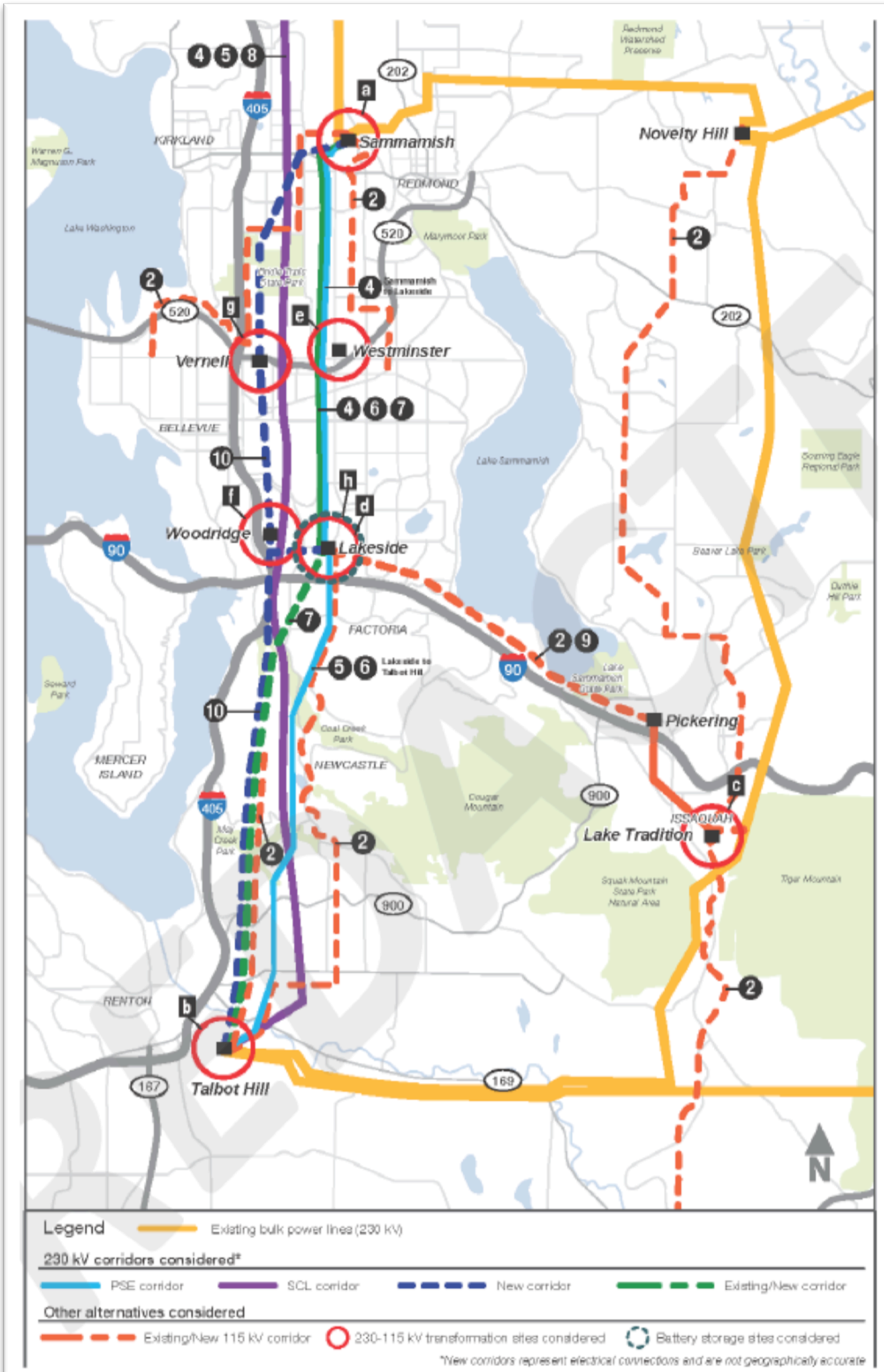
Figure 8-12: Energy Storage Configuration Summary

Configuration	Power (MWp)	Energy (MWh)	Duration (hours)	Est. Cost ($MM)	Includes Non-Wires Alternatives[11]	Technically Feasible	Meets Requirements
Baseline Normal Overload Reduction	328	2,338	7.1	**$1,030**	✓	✕	✓
Alternate #1 Emergency Overload Elimination*	121	226	1.9	**$184**	✓	✓	✕
Alternate #2 Normal Overload Elimination	545	5,771	10.6	**$2,367**	✓	✕	✓

ALTERNATIVE 4 - TRANSMISSION LINE REINFORCEMENTS AND TRANSFORMER ADDITIONS. Combinations of ten transmission line reinforcements and seven transformer additions were reviewed in PSE's 2015 Solutions study as potential solutions to the Eastside transmission deficiency. These transmission line and transformer addition locations are shown in Figure 8-13.

PSE determined that a wires option to construct a new 230/115 kV transformer and 230 kV line with associated ancillary facilities is the preferred solution to solve the Eastside's need.

Figure 8-13: Transmission and Transformer Addition Locations for Energize Eastside



ENVIRONMENTAL IMPACT STATEMENT PROCESS. The Energize Eastside project is undergoing environmental review, which includes preparation of a Washington State Environmental Policy Act (SEPA) Environmental Impact Statement (EIS).

The Phase 1 and Phase 2 Draft EIS evaluated the Energize Eastside alternatives studies, a “No Action” Alternative (as required by SEPA), and three other “action alternatives.” These alternatives were developed by the partner cities in cooperation with PSE, with the intent of providing options that could attain or approximate PSE objectives for the project at a lower environmental cost.

The No Action Alternative provides a benchmark against which the proposed project and other action alternatives can be compared. In 2015, PSE commissioned Nexant to simulate three scenarios of rotating outages that could be needed if no action is taken to upgrade the Eastside’s transmission system. Nexant determined that if PSE must use corrective action plans that include rolling blackouts, more than 130,000 customers could be impacted as early as the summer of 2018, at a cost of tens of millions of dollars to the local economy.

The table below shows the results of the study, which highlights the number of customers and economic impacts of rotating outages.

Figure 8-14: Summary of Outage Cost Analysis by Nexant

Summary of Outage Cost Analysis by Nexant

Scenario	Customer Class	Number of Customers Experiencing Rotating Outages	Total Outage Cost	Customer Load Shed	Cost per Unserved kWh
			$ Millions	MWh	$
Scenario 1, Summer 2018	Medium and Large C&I	2,799	$65.1	2,419	$26.9
	Small C&I	7,983	$23.3	207	$112.5
	Residential	120,213	$3.8	2,093	$1.8
	Scenario 1 Total	**130,995**	**$92.2**	**4,719**	**$19.5**
Scenario 2, Summer 2024	Medium and Large C&I	4,480	$179.3	5,266	$34.0
	Small C&I	14,086	$84.5	577	$146.4
	Residential	192,674	$10.8	4,751	$2.3
	Scenario 2 Total	**211,240**	**$274.6**	**10,594**	**$25.9**
Scenario 3, Winter 2023-2024	Medium and Large C&I	3,142	$153.1	8,897	$17.2
	Small C&I	9,786	$115.7	875	$132.3
	Residential	161,890	$8.1	8,914	$0.9
	Scenario 3 Total	**174,818**	**$276.9**	**18,686**	**$14.8**

Source: Puget Sound Energize Eastisde Outage Cost Study, Oct. 2015; by Nexant, Inc.

- Scenario #1 includes the 230 kV overhead lines, but also includes options for locations, including underground and underwater options. Of these options, the EIS team only carried forward PSE's preferred option of a new substation and 230 kV transmission line.
- Scenario #2 includes a variety of solutions that would require very limited new transmission lines next to existing substations. These would need to be implemented in combination in order to meet the project objectives. The EIS team did not carry this option forward as the solutions do not meet the project objectives, and they would rely heavily on voluntary customer actions in some cases.
- Scenario #3 would involve installing enough 115 kV lines and transformers to address the project objectives without building 230 kV lines. This option was not carried forward for further analysis.[31]

PSE's Preferred Alternative

After extensive study and evaluating and re-evaluating dozens of alternatives both independently and through the Phase I Draft EIS, PSE determined that the most effective solution that meets all criteria and complies with the federal performance requirements is the addition of a 230 kV/115 kV transformer in the center of the Eastside load area. This new transformer would be connected to new 230 kV transmission lines constructed between the Sammamish (Redmond) and Talbot Hill (Renton) substations along with continued aggressive conservation – the Energize Eastside project.

This involves constructing a new 230 kV to 115 kV substation, called Richards Creek, to be located on PSE-owned parcel 1024059130 in Bellevue. The Richards Creek substation property is located immediately south of the existing Lakeside 115 kV substation, which is situated on parcel 1024059083 in Bellevue. The new Richards Creek 230 kV to 115 kV transformer will provide a new electrical capacity source for the Eastside area.

To connect the transformer, PSE will replace two existing 115 kV lines that were last upgraded in the 1960s with two 230 kV lines. Operating both lines at 230 kV has the lowest potential for interaction with the petroleum product pipelines that share the transmission line corridor. Electricity will be transmitted to the Richards Creek substation at 230 kV and then the voltage will be lowered ("stepped down") to 115 kV for distribution to customers on the Eastside.

31 / Per the Phase 2 DEIS: "acquisition of up to 60 miles of right-of-way for new 115 kV lines would likely result in some displacement. Delays due to the legal steps required for such acquisition, which could include condemnation, would not meet the project objectives for timeliness to meet reliability requirements. For these reasons, this alternative was not carried forward."

The existing transmission lines are located in PSE's Sammamish – Lakeside – Talbot Hill corridor, which was established in the late 1920s and early 1930s. Within this existing corridor, the proposed pole locations for the rebuilt lines will generally be in the same locations as the existing poles. In some instances, there may be advantages to moving pole locations to accommodate landowner preferences and/or reduce potential environmental impacts (for example, to move existing pole locations out of wetlands).

These facilities are needed to address the deficiency in electrical transmission capacity during peak periods that PSE identified through its system planning process. This project will improve reliability for Eastside communities and supply the needed electrical capacity for growth and development on the Eastside.

Engaging the Community on Energize Eastside

In today's increasingly connected and rapidly changing environment, PSE recognizes the need for openness and transparency so that interested parties are able to quickly access relevant expertise and information.

Since launching the Energize Eastside project in December 2013, PSE has engaged the Eastside community in a robust public involvement process. This process has included mailings, public meetings and direct outreach efforts to ensure that stakeholders are informed about the project and have had plentiful and diverse opportunities to participate. PSE's public involvement process, especially with regards to routing, has been conducted over and above formal environmental review and permitting requirements.

To date, public outreach and involvement has included:

- **22** Community Advisory Group-related meetings
- **6** public open houses, **2** question and answer sessions, and **2** online open houses at key project milestones
- **500+** briefings with individuals, neighborhoods, cities and other stakeholder groups
- More than **2,900** comments and questions received
- **30+** email updates to more than **1,500** subscribers
- **8** project newsletters to **55,000+** households
- Ongoing outreach to **500+** property owners, including door-to-door and individual meetings
- Participation in **16** EIS-related public meetings

In addition, PSE's Energize Eastside website provided project updates and functioned as a repository for project materials, including maps, technical studies like the need and solution studies, the Community Advisory Group Final Report, fact sheets on a wide range of topics, newsletters, meeting summaries and other materials.

An overview of the public engagement process follows.

PHASE 1: PUBLIC ROUTE DISCUSSION (2014). To provide a forum that would generate robust input from diverse community stakeholders, PSE convened a Community Advisory Group to consider community values when evaluating transmission line route options. The advisory group spent a year learning about the Eastside's electrical system, participating in meetings and workshops and evaluating 18 route options identified by PSE.

In addition to the Community Advisory Group, PSE involved the community through public meetings, neighborhood meetings, briefings and comments, which provided Eastside residents opportunities to share their community values and ask initial questions about the project. For details about the advisory group process, review the Community Advisory Group Final Report (2015).[32]

PHASE 2: FIELDWORK AND ENVIRONMENTAL REVIEW (2015 – TODAY). In 2015, PSE began collecting field information necessary for design and environmental review. PSE kept stakeholders informed about these fieldwork activities to ensure residents knew when crews were expected to perform surveys near their homes and businesses.

In 2015, the project began environmental review, which includes preparation of a Washington State Environmental Policy Act Environmental Impact Statement. The City of Bellevue leads the EIS process in cooperation with Newcastle, Kirkland, Redmond and Renton. The SEPA process is a separate regulatory requirement that must be completed before any permits may be issued and includes public involvement milestones.

PSE has provided supplemental EIS notifications about major milestones and comment periods to keep stakeholders informed and to support community engagement. In addition, PSE has participated in eight scoping meetings and eight draft EIS hearings over the two-phased EIS process. The Final EIS is anticipated in early 2018.

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32 / https://energizeeastside2.blob.core.windows.net/media/Default/CAG/2015_0114_Energize_Eastside_CAG_Final_Report_FINAL_for_web.pdf

PHASE 3: PROPERTY-OWNER CONSULTATIONS (2016 – TODAY). As project design progressed, PSE began reaching out to individual property owners to share information and answer questions. In spring 2016, the project team visited neighborhoods along the existing corridor and Factoria area in Bellevue to talk with residents and business owners about the project. This door-to-door outreach was conducted to help inform customers about the project status and to address questions and concerns from property and business owners.

In September 2016, PSE began meeting with property owners and tenants along the existing corridor to discuss property-specific design and tree replacement plans. We shared our current design for that specific property, including pole locations and how we plan to access those locations during construction. These conversations have helped us refine our project design and better understand customer interests and concerns.

In May 2017, PSE began meeting with property owners to begin developing property-specific landscaping and tree replacement plans with property owners. We are currently reaching out to affected property owners about these efforts.

FUTURE PHASES: PERMITTING AND CONSTRUCTION. PSE expects to begin submitting permit applications in summer 2017 to keep the project moving forward.

We value the community's input and ongoing interest in the project, and PSE is committed to keeping property owners and the community informed about its progress. Visit the project website at www.energizeeastside.com for the latest information and for more details about how the public has been involved in Energize Eastside.

Gas Infrastructure Plan

Pressure Regulation Stations

In the next decade PSE plans to build or upgrade approximately 7 Northwest Pipeline-supplied gate or limit stations and 16 district regulator stations to serve load as existing station capacity is exceeded.

Pipelines

In the next decade, PSE expects to add approximately 24 miles of high pressure main and 23 miles of intermediate pressure main as loads grow in our service area.

Ongoing Maintenance

As with the electric system, PSE is continually addressing aging gas infrastructure within the system in accordance with regulatory requirements and operating practices. In the next decade, PSE plans to replace 200 to 300 miles of gas main that is reaching the end of its useful life. As mentioned above, PSE anticipates replacing its current aging and obsolete Automated Meter Reading (AMR) communication system and gas customer modules with Advanced Metering Infrastructure (AMI) technology to enable smart grid enhancements and future customer offerings.

Figure 8-15: Summary of 10-year Gas Infrastructure Plan

ASSET	NUMBER	LOCATION
New High Pressure Main	24 miles	System-wide
New Intermediate Pressure Main	23 miles	System-wide
Gate or Limit Station Upgrades	Seven	System-wide
District Regulation	Sixteen	System-wide
Gas Main Replaced	200-300 miles	System-wide

Planned Gas Supply System Improvements

PSE has included higher pressure projects that are associated with the operations at greater than 250 psig and which are significant in cost due to complexity. In this discussion, these are defined as costing $10 million or greater over the next 10 years.

PROJECTS COMPLETED SINCE LAST 2015 IRP. (Information on a variety of projects completed within the last six months can be found on PSE's website at https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Completed-improvements.aspx.)

1. **Tolt Pipeline (Phase 1)**[33]
   Date of Operation: 2015-2018
   The project is intended to provide additional *capacity* and *reliability* to serve the growth from Bothell/Woodinville to Bellevue. Phase 1 of the project involves constructing 2.8 miles of 16-inch high pressure main.

FUTURE PROJECTS

2. **North Seattle Reinforcement Projects**
   Estimated Date of Operation: 2020+
   This collection of projects will increase *capacity* and *reliability* to serve existing load and growth in the north Seattle area, from Lynnwood to southern Seattle. These projects are in the planning phase and consist of upsizing or adding new high pressure main and regulation.

3. **South Tacoma Distribution Upgrades**
   Estimated Date of Operation: 2020+
   This collection of projects will increase *capacity* and *reliability* to serve growth in the Tacoma area, from Tacoma to DuPont and Bonney Lake. These projects are in the design phase, which consists of upsizing, looping or adding new intermediate pressure main.

4. **Tolt Pipeline (Phase 2)**[34]
   Estimated Date of Operation: 2020+
   Phase 2 of this project will increase *capacity* and *reliability* to serve growth in the greater Eastside area, from Bothell/Woodinville to Bellevue. Phase 2 of the project involves constructing 1.2 miles of 16-inch natural high pressure main.

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33 / https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Tolt-Natural-Gas-Line-Project.aspx
34 / https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Tolt-Natural-Gas-Line-Project.aspx

Areas of Future Focus

PSE will continue to improve the gas system planning process as more data regarding demand and conservation potential becomes available with technologies such as Advanced Metering Infrastructure. As technologies mature, alternatives will be refreshed and reevaluated when necessary. Generally, alternatives to date are various infrastructure solutions such as uprating, regulation or pipeline upgrades. Due to the complexity of larger planned system improvement projects the first gate of project development known as Initiation will refine the need and reconfirm preliminary alternatives and solutions and consider implementation challenges and new information. This process targets needs that are more than four to five years out in order to provide adequate review and engagement. This process will improve as PSE matures its ability to predict localized circuit-level load growth and conservation potential. Additionally, the incorporation of learnings about alternative technologies and applications will be important as well.

6. CHALLENGES AND OPPORTUNITIES

New Regulations

Regulatory compliance is a significant driver of PSE infrastructure investment, but it is difficult to anticipate what rules may be adopted in the future or to predict how they may impact spending on our delivery systems. The following examples from the last decade illustrate the kind of expenditures that regulatory activity can necessitate.

Gas System

Beginning with the Pipeline Safety Improvement Act (PSIA) of 2002 and again in 2006 with the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act, Congress has directed the Pipeline and Hazardous Materials Safety Administration to increase the strength of integrity management programs that cover natural gas transmission and distribution pipelines. These programs require PSE to perform detailed inspections and analysis of pipeline systems to gain more knowledge of pipeline integrity risks and to devise measures to mitigate these risks. Numerous actions have resulted from these requirements, including expanded pipe replacement programs, enhanced damage prevention activities and increased inspection intervals. These expanded pipe replacement programs have increased both the number and footage of projects.

Pipeline safety incidents which have occurred across the country continue to focus the attention of state and federal regulators and lawmakers on improving pipeline and public safety performance. Proposed legislation includes:

- expanding the mileage of pipelines subject to more rigorous inspection and testing,
- requiring the use of automatic and remote controlled shut-off valves,
- expanding the use of excess flow valves, and
- requiring more timely notification of pipeline incidents.

All would require additional investment in processes and infrastructure to support compliance.

Electric System

In 2007, new regulations mandated by The Energy Policy Act of 2005 became effective and enforceable by regional electric reliability organizations. This act was triggered by concern about the robustness and reliability of nation's electrical grid, and it moved the industry into an era in which system planning, performance and operating requirements are no longer voluntary, but mandated by law and audited and enforced by fines and sanctions. At minimum, the PSE Bulk Electric System must be planned and operated to comply with these new reliability standards. As a result, PSE is making significant investments in both hardware and software assets for the portions of our system operating above 100 kV.

Regulations of the type affecting the Bulk Electric System are not currently present on the distribution system. However, distribution planning continues to be of interest in state legislative proceedings and with regulators. Current proposed legislation would establish a new reporting requirement for utilities to define a plan to foster the application and use of distributed generation.

New drone technology and FAA regulations have the potential to gather system information that may be useful in future planning exercises. PSE began evaluating areas where this technology may be utilized in 2015/2016.

Maturing System Alternatives

Finding optimal solutions to energy delivery system problems is a priority for PSE, and we are piloting and implementing several maturing technologies and alternatives that have the potential to help meet today's challenges and future challenges. While some technologies are mature enough for customer applications, the scalability and integration for meeting system needs is still maturing for the utility. Distributed energy resources have been considered by PSE for many years in the planning model, and as they mature they will become more viable to offset the reliability of traditional infrastructure solutions. Customer reliability and rates are key considerations to intentionally advancing these ideas so that no harm comes from applications that are not effectively scalable. Informing customers and stakeholders about the capability and viability of these technologies is also an important priority for PSE.

Smart Grid Technologies

Smart Grid is a term used to describe the integration of intelligent devices and new technologies into the electrical grid that promote self-healing and enable customer choice to a degree not possible with the grid's original infrastructure. At a basic level, these technologies are a networked group of generators, storage systems, sensors and control systems that allow for an optimized response to changes. The solutions are highly complex and require new technology integrations, complementary tariffs and policies governing their use, and extensive reengineering of business processes and work practices. PSE's objectives for the smart grid include the abilities to: meet customer expectations for service and product offerings, improve reliability, find alternatives to serving energy needs, increase operational efficiencies, and improve communication and usage information for customers.

PSE has set forth plans for a smart grid in the biennial Smart Grid Technology Report[35] filed with the WUTC in 2016. PSE will leverage existing investments in smart grid technologies while expanding the foundational elements to more fully integrate smart grid technology. PSE will demonstrate the value of smart grid technology in both targeted locations as well as in field test beds. Demonstrations in the targeted locations will focus on technology that is more mature and ready for expanded implementation throughout our service area such as distribution automation, advanced meter infrastructure (AMI) and conservation voltage reduction. To evaluate more cutting edge and complex technologies and test the interplay and impacts that these technologies have when combined, field test beds will be conducted in small, neighborhood-sized sections of our service area.

PSE is planning for distributed generation integration and control, coupled with demand response and voltage optimization. These technologies, when successfully implemented, are the cornerstones of a smart grid. As they are implemented together successfully, PSE will look to expand to more locations.

35 / *https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=161048*

To accomplish this vision, PSE will pull from decades of experience with grid technologies, many of which were cutting edge implementations at their time, including its use of transmission automation, AMR and system-wide SCADA. With implementation and improvements to Outage Management System (OMS), Geographical Information System (GIS) and Customer Information System (CIS), Energy Management System (EMS), and Internet Protocol (IP) based Supervisory Control and Data Acquisition (SCADA) network, PSE will be able to further advance operation and efficiency. Current work includes replacement of the aging AMR system with an AMI system capable of command and control which will increase the viability of alternatives that save energy and defer or delay traditional infrastructure; investigation of an advanced distribution grid management system (ADMS) that will facilitate control of distribution assets for distribution automation, voltage optimization and distributed generation integration; and continued replacement of PSE's legacy analog networks and obsolete remote telemetry unit equipment.

Distributed Generation

Distributed generation (DG) is the incorporation of small-scale generation into the electric grid close to where its users are (close to load). Many such sources exist: internal combustion engines, fuel cells, gas turbines and micro-turbines, hydro and micro-hydro applications, photovoltaics, wind energy, solar thermal energy and waste/biomass. The collective impact of distributed generation has the potential to reduce demand for large-scale electric power generation and the associated infrastructure requirements, and it could offer alternatives to load and reliability concerns at the circuit level.

PSE has incorporated distributed generation into its planning process for many years, but the maturity of the technology and grid created barriers to implementing DG as a cost-effective alternative to system improvements; however, the maturity of the technology is increasing. PSE has already responded to over 4,000 customers who have interconnected distributed renewable generators under 100 kW (mostly solar), and the number of requests is increasing annually. Also, several customers have participated in tariffs to interconnect larger generators sized between 100 kW and 5 MW; these interconnections follow an established procedure and timeline for study and cost assignment. PSE has interconnected 20 such customers so far. Most interconnections thus far desire to redirect surplus back on to the grid which requires reliable infrastructure to make that happen. Additionally, while the growing interconnections will offset total load, peak load reduction is less likely because PSE's peak loads often occur outside of daylight hours when solar generators are not producing. PSE sizes the delivery system to meet peak loads; however, the growing use of energy storage may influence the ability for DG to impact peak loads.

Distributed generation in PSE's service territory has not yet triggered significant impacts to the grid resulting from the two-way power flow, but several challenges arising from distributed generation have yet to be fully addressed. The upstream impacts of the two-way flow require a different approach to protection and control systems. PSE is also monitoring the impact of inverter technology on power quality. Even a modest amount of distributed generation requires the distribution grid to be equipped to manage power quality, thermal and mechanical limits of the grid elements, power system stability and the security of supply. Research in states that experience high penetrations of distributed generation points to several technologies that support its adoption. These include smart inverter technology, distributed generation control systems, upgrading and uprating distribution grid elements, and integrated storage.

Energy Storage

PSE's experience with grid-scale energy storage started with a 2MW project in the town of Glacier, Wash., in Whatcom County. To integrate this storage component, PSE needed to invest in protection upgrade at the substation, replacing the substation fuses with a circuit switcher. In addition, because the storage system required communications with the central energy management control system, PSE needed to install adequate communication networks to enable this communication. PSE's 2 MW battery will support about 150 customer homes for a day.

The vision for the battery is to perform peak shaving, frequency support and local outage mitigation. The battery has demonstrated its capabilities with regard to peak shaving and frequency support, and PSE is still working to demonstrate the ability to provide local outage mitigation. Because the town of Glacier is fed by a radial transmission line and radial distribution system, when either of these lines experiences an outage, there is no redundancy or backup available to mitigate the outage. Before power can be restored, repairs must be made to the lines. The battery may provide a new alternative, if it can provide power to the town when damage occurs to the transmission line or certain sections of the distribution lines. Otherwise, alternatives for redundancy are to bring in new transmission lines and add feeder ties to other substations, but in a remote area like Glacier, adding these new circuits would require many miles of new lines, an option for which the costs outweigh the benefits. Hence, a battery that can mitigate a subset of the outages offers a unique opportunity. (Read more about energy storage in Appendix L.).

Unlike a distributed generator, energy storage acts as a load on the grid as well as a generation source. PSE will need to consider how charging the battery impacts the demands on the grid. Additionally, robust and reliable infrastructure will still be required to support alternatives such as siting large batteries to feed partial or entire circuits or siting many small batteries to feed several houses.

Conservation Voltage Reduction

Reducing the voltage at an end-user's site by a small percentage can result in energy savings without compromising the operation of customers' equipment. PSE began a conservation voltage reduction (CVR) pilot program in conjunction with Northwest Energy Efficiency Alliance (NEEA) in 2006 implementing a pilot study of 10 residential customers that achieved a 2 percent energy savings with no adverse effects. Results on more recent PSE projects are showing an average of 1.5 percent energy savings on the substation circuits.

Since then, PSE has implemented CVR at six substations. Implementation involves three categories of work: installation of AMI meters to measure voltage near the end of the line, phase balancing and adjusting voltage settings at the substation transformer and line regulators. Because CVR relies on AMI metering to measure voltage, so far the implementation has been viable in areas where PSE has piloted AMI network and metering in advance of full AMI implementation. As full AMI implementation is completed, changes to IT systems and business processes will provide the opportunity to implement CVR more broadly across PSE service territory over the next 5 to 10 years. This will improve the viability of CVR as an alternative to implementing traditional infrastructure or generation solutions to address local capacity concerns.

Demand Response Alternatives

When demand for power is at its highest and customers reduce their energy use in response, utility energy delivery system planners call this demand response (DR). Based on estimated demand response capacity for residential, commercial and industrial customer sectors in our 2007 and 2009 IRPs, PSE developed two voluntary demand response pilots, one for residential loads that was conducted from 2009 to 2011, and one for commercial/industrial loads that was conducted from 2008 to 2010. In the 2015 IRP, the analysis found demand response to be a cost-effective resource in the demand-side portion of the portfolio. Based on those findings, PSE has moved forward with an acquisition strategy for demand response.

The acquisition strategy for DR includes consideration of the technology and management needed to ensure response is effective. Viability at the local or circuit level as an alternative to traditional infrastructure solutions will depend on the confidence we have in managing this program. PSE anticipates increasing utilization of DR over time. As with CVR, the fully implemented AMI system, with its improved technology and two-way communication, will facilitate more meaningful progress in implementing DR.

Electric Vehicles

PSE's customers are adopting electric vehicles (EV). In 2014, PSE launched a pilot program to collect interval energy usage data from EV owners. Over 1,100 customers have joined the pilot, providing PSE with a large population of data points. This information is used to develop load curves which will ultimately inform cost of service, distribution system impacts, and generation and transmission system impacts. We have developed estimates of expected energy needs, performed initial assessment of distribution impacts on select circuits, and performed some tests on the effectiveness of curtailed charging.

EVs are not specifically an alternative to traditional infrastructure or generation, but the future penetration and load impact must be considered and managed effectively. To date, PSE has determined that EVs pose minimal impacts to generation and transmission systems in the short run. Near-term distribution system impacts are small and likely manageable. In significant numbers, the additional loads from EVs could enhance the efficiency and economics of operating the electric system, with greater results achieved by encouraging off-peak charging when the system has spare capacity. However, unmanaged (through tariff incentives, for example), the peak demand on a specific circuit may increase significantly and actually drive infrastructure. PSE is working with the EV community to prepare effectively as adoption increases.