2021 PSE Integrated Resource Plan

Chapters 1-9

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FINAL

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PSE PUGET SOUND ENERGY

2021 PSE Integrated Resource Plan

About PSE

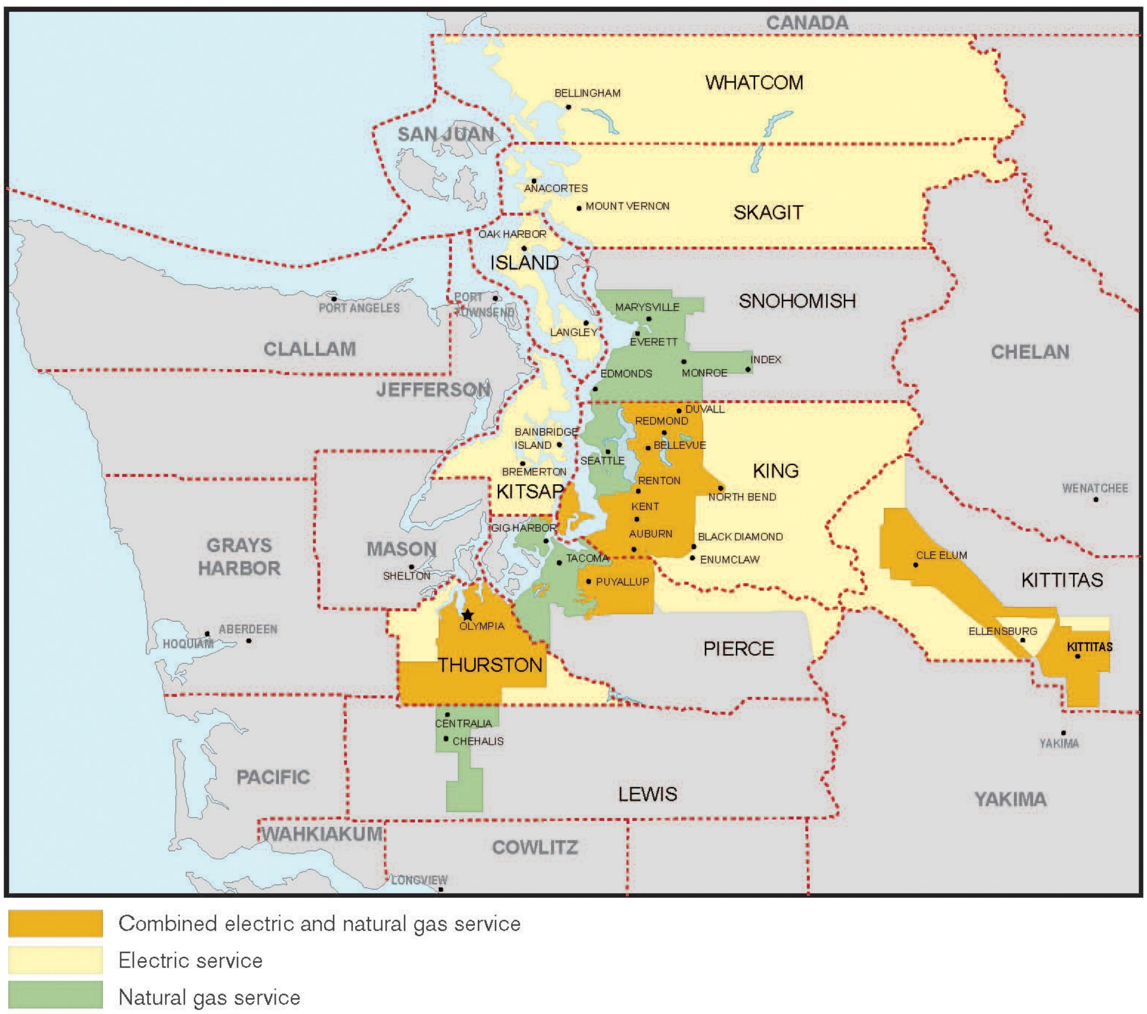
As Washington state's oldest local energy company, Puget Sound Energy serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula.

Electric service: All of Kitsap, Skagit, Thurston, and Whatcom counties; parts of Island, King (not Seattle), Kittitas, and Pierce (not Tacoma) counties.

Natural gas service: Parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties.

PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources and farsighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient.

Figure i-1: PSE's Service Area



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Definitions and Acronyms

Term/ Acronym	Definition
A4, A5	A standard for converting gases to carbon dioxide equivalents using the Intergovernmental Panel on Climate Change global warming protocols.
AARG	average annual rate of growth
AB 32	California Global Warming Solutions Act of 2006, which mandates a carbon price to be applied to all power generated in or sold into that state.
ACE	Area Control Error
ACE Rule	Affordable Clean Energy Rule. Adopted in 2018, EPA's replacement for the Clean Power Plant Rule.
ADMS	Advanced Distribution Management System, a computer-based, integrated platform that provides the tools to monitor and control distribution networks in real time.
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
ATC	available transmission capacity
AURORA	One of the models PSE uses for electric resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. AURORA is also used to test electric portfolios to evaluate PSE’s long-term revenue requirements.
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.
Baseload combustion turbines	Baseload combustion turbines 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.
BAU	business-as-usual
Bcf	billion cubic feet
BEM	Business Energy Management sector, for electric energy efficiency programs.
BES	bulk electric system
BESS	battery energy storage 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
CAA	Clean Air Act
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 plan, a series of operational steps used to prevent system overloads or loss of customer power.
CAR	Washington State Clean Air Rule
CARB	California Air Resources Board
CBI	customer benefit indicator
CCCT	Combined-cycle combustion turbine. Baseload generating plant that consists 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

CEAP	Clean Energy Action Plan
CEC	California Energy Commission
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CFS	conditional firm service, a new transmission product offered by BPA.
CHP	combined heat and power
CI	confidence interval
CIA	cumulative impact analysis
CIA	community impact assessment
C&I	commercial and industrial
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.
CPA	conservation potential assessment
CPI	consumer price index
CPP	federal Clean Power Plan
CPP	critical peak pricing or dynamic pricing
CPUC	California Public Utilities Commission
CRAG	PSE's Conservation Resource Advisory Group
C&S	codes and standards
CT	combustion turbine
CVR	conservation voltage reduction
DA	distribution automation
DE	distribution efficiency
DER	distributed energy resources
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 demand. They include energy efficiency, distribution efficiency, generation efficiency, distributed generation and demand response.

DER	Distributed energy resources. Electricity generators like rooftop solar panels that are located below substation level.
DERMS	Distributed Energy Resource Management System
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.
DG	distributed generation
distributed energy resources	Small-scale electricity generators like rooftop solar panels, located below substation level.
DLC	direct load control, one of several demand response programs
DMS	distribution management system
DOE	U.S. Department of Energy
DOH	Washington State Department of Health
DR	demand response
DSM	demand-side measure
DSM	demand-side management
DSO	Dispatcher Standing Order
DSP	Delivery System Planning
DSR	demand-side resources
Dth	dekatherms
dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EDAM	extended day-ahead market
EE	energy efficiency
EEI	Edison Electric Institute
EHD	environmental health disparities
EHEB	Economic, Health and Environmental Benefits Assessment
EIA	U.S. Energy Information Agency
EIA	Washington State Energy Independence Act
EIM	The Energy Imbalance Market operated by CAISO
EIS	environmental impact statement
EITEs	energy-intensive, trade-exposed industries

ELCC	Effective load carrying capacity. The peak capacity contribution of a resource calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP resource adequacy metric constant.
EMC	PSE's 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.
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
FLISR	Fault Location, Isolation, Service Restoration
GDP	gross domestic product
GENESYS	The resource adequacy model used by the Northwest Power and Conservation Council (NPCC).
GHG	greenhouse gas
GIS	Geographic Information System
GPM	gas portfolio model
GRC	General Rate Case
GTN	Gas Transmission Northwest
GW	gigawatt
HB 1257	Clean Buildings for Washington Act
HDD	heating degree day
HIC	Highly impacted communities
HILF	high-impact, low-frequency events
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.
IAP2	International Association of Public Participation
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
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
LAES	liquid air energy storage
LNG	liquified natural gas
load	The total of customer demand plus planning margins and operating reserve obligations.
LOLE	Loss of load expectation, a reliability metric that measures the number of days per year with loss of load due to load exceeding available system capacity.
LOLH	Loss of load hours (or loss of load energy), a reliability metric that measures the duration of electric service curtailment events (how long outages may last).
LOLP	Loss of load probability, a reliability metric that measures the likelihood of an electric service curtailment event happening.
LP-Air	vaporized propane air
LSR	Lower Snake River Wind Facility
LTCE	long-term capacity expansion model
LTF	long-term firm transmission

LTF PTP	long-term firm point-to-point transmission
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.
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
NOAA	National Oceanic and Atmospheric Administration
NOS	Network Open Season, a BPA transmission planning process.
NO_x	nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	net present value
NRC	Nuclear Regulatory Commission

NREL	National Renewable 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.
NTTG	Northern Tier Transmission Group
NUG	non-utility generator
NWA	non-wires analysis
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
OMS	outage management system
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 spikes 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
PHES	pumped hydro energy storage

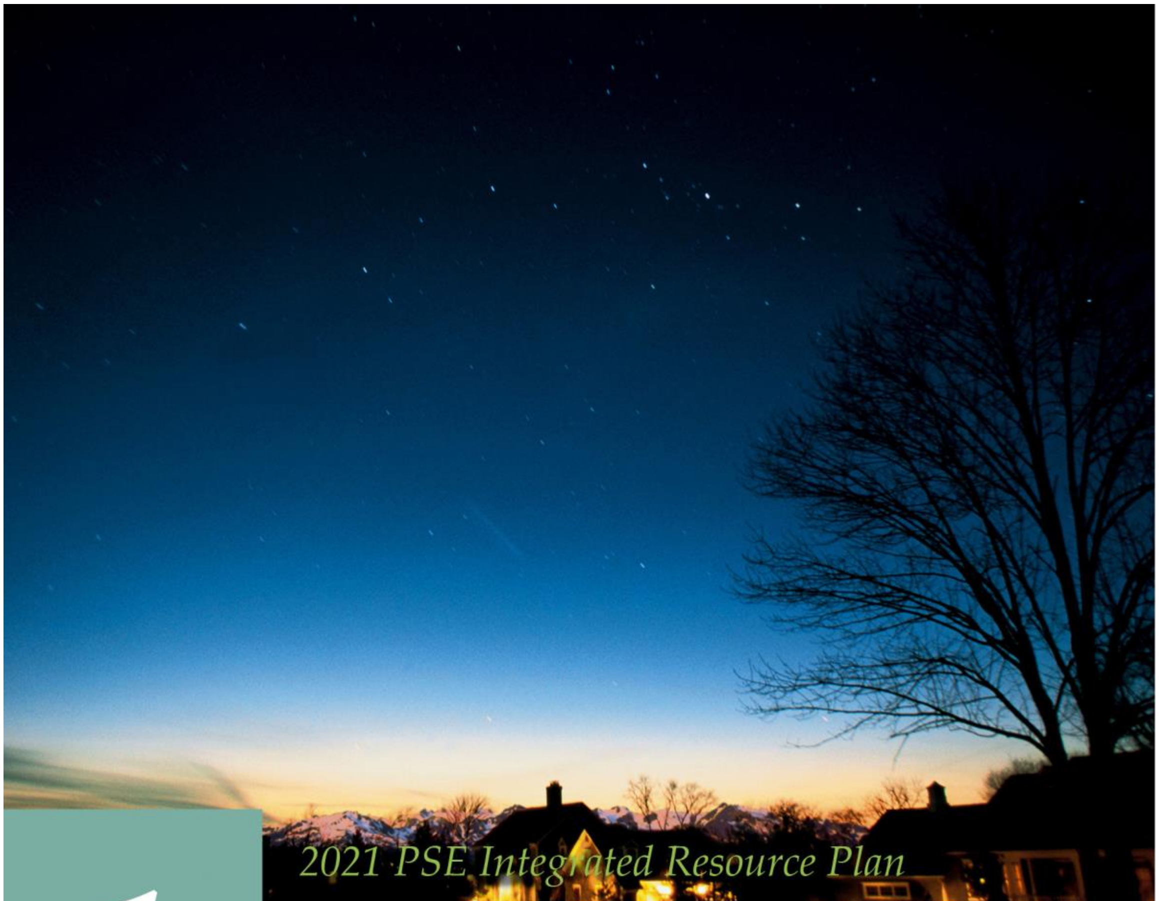
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
planning margin or PM	These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events.
planning standards	The 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
POD	point of delivery
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
PSCAA	Puget Sound Clean Air Agency
PSE	Puget Sound Energy
PSEM	Puget Sound Energy Merchant, the part of PSE responsible for obtaining and scheduling the transmission needed to serve PSE loads.
PSIA	Pipeline Safety Improvement Act (2002)
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
RA	resource adequacy
RAM	Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical reliability.
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 entering into 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
RHA	Renewable Hydrogen Alliance
RNG	renewable natural gas
RPS	Renewable portfolio standard. A requirement that electricity retailers 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 that provides real-time visibility and remote control of distribution equipment
SCCT	Simple-cycle combustion turbine, a generating unit capable of ramping up and down quickly to meet 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.
SCC	social cost of carbon, also called SCGHG, social cost of greenhouse gases
SCGHG	social cost of greenhouse gases
SCR	selective catalytic reduction
SEIA	Solar Energy Industries Association
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 Mid 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, natural 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 natural gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
T&D	transmission and distribution
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 or alternative 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.
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.
TSR	transmission service request
TSEP	Bonneville Power Administration's transmission service request study and expansion process.
UPC	use per customer
VectorGas	An analysis tool that facilitates the ability to model price and load uncertainty.
VERs	variable energy resources

VPP	virtual power plant
VVO	volt-var optimization
WAC	Washington Administrative Code
WACC	weighted average cost of capital
WCI	Western Climate Initiative
WCPM	Wholesale Purchase 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



1 Executive Summary

The Integrated Resource Plan (IRP) is best understood as a planning exercise that evaluates a range of potential future outcomes, considering customer needs, policies, costs, economic conditions and the physical energy system. It's the starting point for making decisions about what resources PSE may procure in the future.

Contents

1. OVERVIEW

The Integrated Resource Plan (IRP) is a planning exercise that evaluates how a range of potential future outcomes could affect PSE's ability to meet our customers' electric and natural gas supply needs. The analysis considers policies, costs, economic conditions and the physical energy system, and proposes the starting point for making decisions about what resources may be procured in the future.

Plan Highlights

The 2021 PSE electric and natural gas IRPs have been developed during a time of extraordinary change as policy makers, the utility industry and the public confront the challenge of climate change and the necessity to transition to a clean energy future.

PSE is committed to reaching the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and the electric resource plan presented here reflects these changes and goals. It includes:

- significant investments in renewable resources
- accelerated acquisition of energy conservation
- increased use of demand response
- integration of distributed energy resources like residential solar and battery energy storage
- reduced reliance on short-term market purchases in response to the changing western energy market
- inclusion of alternative fuels to operate new generating plants

The preferred portfolio reduces direct carbon emissions from PSE's electric supply by over 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments that enable a significant decrease in the generation from fossil fuel-based resources, and through alternative compliance options that may include additional renewable resources, energy efficiency, unbundled renewable energy credits or other energy transformation projects.

Legislation enacted in 2019 requires total natural gas costs to include the social cost of greenhouse gasses and related upstream carbon emissions. As a result of this policy change, the natural gas resource plan focuses on significant, aggressive acquisition of conservation due to the increase in total natural gas costs. Since the natural gas IRP analysis was completed prior to the conclusion of the 2021 Washington state legislative session, it does not include new legislation that may, if enacted, substantially change the use of natural gas in certain sectors. The requirements of any new legislation will be included in the 2023 natural gas IRP.

It is important to recognize that the IRP does not make resource or program implementation decisions. The IRP is a long-term view of what appears to be cost effective based on the best information we have today about the future. The electric IRP analysis is repeated every four years and updated every two years. The IRP's forecasts and resource additions will change as technology advances, clean fuel options increase, resource costs decline, the wholesale energy market evolves and new policies are established. The IRP includes the Clean Energy Action Plan (CEAP). The Clean Energy Implementation Plan (CEIP) starts where the IRP/CEAP ends and develops specific four-year targets for solutions proposed in the IRP/CEAP, taking into account the equitable distribution of customer benefits and the feasibility of implementation.

Public Participation

Public and stakeholder engagement is an essential part of developing an IRP, and the engagement generated valuable feedback and suggestions from organizations and individuals that helped inform the IRP analysis. Despite the challenges posed by the pandemic, this IRP has been developed with an increased level of public participation:

- 13 public webinars were hosted, recoded and documented, between May 2020 and April 2021.
- 32 email communications were distributed to an IRP audience of over 1,400 members.
- On average, 68 participants joined the webinars and 212 unique individuals participated at least once in the process.
- The re-designed IRP website generated over 14,500 visits.
- 303 stakeholder feedback forms, with 683 stakeholder comments, were received and responded to by PSE.
- 43 scenarios and portfolio sensitivities, developed in partnership with the IRP stakeholders, were analyzed and are documented in Chapters 8 and 9.

All webinar registration information, agendas, presentation materials, technical data files, webinar recordings, chat logs and transcripts, stakeholder feedback forms, and documentation of how stakeholder feedback influenced the IRP are available online at pse.com/irp and in Appendix A.

Public involvement will continue to increase as PSE applies lessons learned from the IRP to development of the CEIP, expands public participation in the delivery system planning process and establishes an Equity Advisory Group to advise PSE as it works to ensure that all PSE customers benefit from the transition to clean energy.

Beyond Net Zero by 2045

In January 2021, PSE pledged to become a **Beyond Net Zero Carbon** energy company by 2045. The goals are aspirational, but the commitment to statewide carbon reduction is steadfast. We pledge to:

- Reduce emissions from PSE electric and natural gas operations and electric supply to net zero by 2030.
- Reach net zero carbon emissions for natural gas sales by 2045 for customer use in homes and businesses, with an interim target of a 30 percent reduction by 2030.
- Go beyond PSE’s own emissions to reduce carbon emissions in other sectors by partnering with customers and industry to identify programs and products that will enable a decarbonized region.

We do not have all of the answers yet, but with the right combination of legislative, regulatory, commercial and technological enablers, we think this degree of emission reduction is possible. PSE will leverage its decades of experience with renewable energy projects, conservation and innovation, but we will also need support and cooperation from our partners, stakeholders, developers and the community to achieve success.

Knowing the complexity of the issues involved and the need to meet many different interests, PSE is convening an external advisory committee with representation from a diverse set of community members, partners, technical experts and others.

2. CHANGES IN THE WHOLESALE ELECTRIC MARKET

While the western energy market has had surplus capacity for more than a decade, PSE's 1,500 MW of firm transmission to the Mid-Columbia market hub has served as a cost-effective means of meeting demand by accessing energy supply from the regional power market. However, the supply/demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: Region-wide, the wholesale electric market is experiencing tightening supply and increasing volatility.

TIGHTENING SUPPLY. As customers, corporations and state legislatures across the Western Interconnect prefer or require power from clean energy sources, the market's resource mix has changed. Since 2016, nearly 15,000 MW of clean energy resources, namely intermittent wind and solar, and 500 MW of batteries have been added to the Western Interconnect, while at the same time, 12,000 MW of traditional, dispatchable coal and natural gas resources have been retired or mothballed. With less dispatchable generation capacity within the Western Interconnect, market supply/demand fundamentals have tightened.

INCREASING VOLATILITY. In response to tighter supply/demand conditions, volatility has also increased. While wholesale electricity prices remain low, on average, in the Pacific Northwest, the region is starting to experience energy price spikes when there is limited supply. Notable events include the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip, and March 2019, when regional cold temperatures coincided with reduced Westcoast pipeline and Jackson Prairie storage availability. Most recently, in August 2020, a west-wide heat wave caused many entities in the region to take a range of actions from energy alerts to rolling blackouts.

As a result of tightening supply and increasing volatility, regional power suppliers are changing how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility by utility, could be an important step toward improving reliability in the region. Numerous regional entities, including PSE, are collaborating on development of a regional resource adequacy program. Should PSE determine the program meets the needs of PSE customers, it will be incorporated into future resource planning activities.

In the past, PSE's firm transmission capacity from the Mid-Columbia market hub has been assumed to provide PSE with access to reliable market purchases under WSPP, Schedule C[1] contracts through which physical energy can be sourced in the short-term bilateral power markets. Historically, PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. For this IRP, PSE conducted a market risk assessment to evaluate the ongoing availability of these short-term power contracts. The assessment resulted in a recommendation to limit the amount of WSPP, Schedule C contracts for the real-time, day-ahead and term market purchases within the three-year purview of PSE's Energy Supply Merchant. This recommendation will transition the historical 1,500 MW limit to a 500 MW limit by the year 2027. To replace those short-term contracts, PSE will seek firm resource adequacy qualifying capacity contracts, compliant with CETA, that meet PSE's resource adequacy requirements and align with a potential regional resource adequacy program. The peak capacity resource need and the preferred portfolio in this IRP reflect the addition of firm resource adequacy qualifying capacity contracts, while reducing the amount of short-term market purchases.

PSE's recommended approach allows PSE to survey the market for available resource adequacy qualifying agreements, and it allows for the development of the regional resource adequacy program requirements, which will help inform PSE's future needs. PSE commits to ongoing review and evaluation of resource adequacy needs as the region addresses capacity deficits, and we expect to continue to address this high-priority issue in the 2023 IRP progress report. Ongoing technology advancements, the outcome of the All-source Request for Proposal (RFP), and regional resource adequacy program developments are expected to inform the IRP progress report.

1/ https://www.wspp.org/pages/Agreement.aspx

3. ELECTRIC RESOURCE PLAN

The preferred electric portfolio is the result of IRP analyses that evaluate a range of potential future resource portfolios to identify the lowest reasonable cost, least risk portfolios that meet customer needs, policy requirements and support the equitable transition to a clean energy future, while maintaining affordability and reliability for customers. PSE's commitments to these objectives are embodied in the preferred portfolio.

The preferred portfolio should be interpreted as a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource and technology trends today. PSE does not make resource decisions in the context of the IRP; actual resource decisions are based on real costs and feasibility discovered through the resource acquisition process and the Clean Energy Implementation Plan.

Electric Resource Need

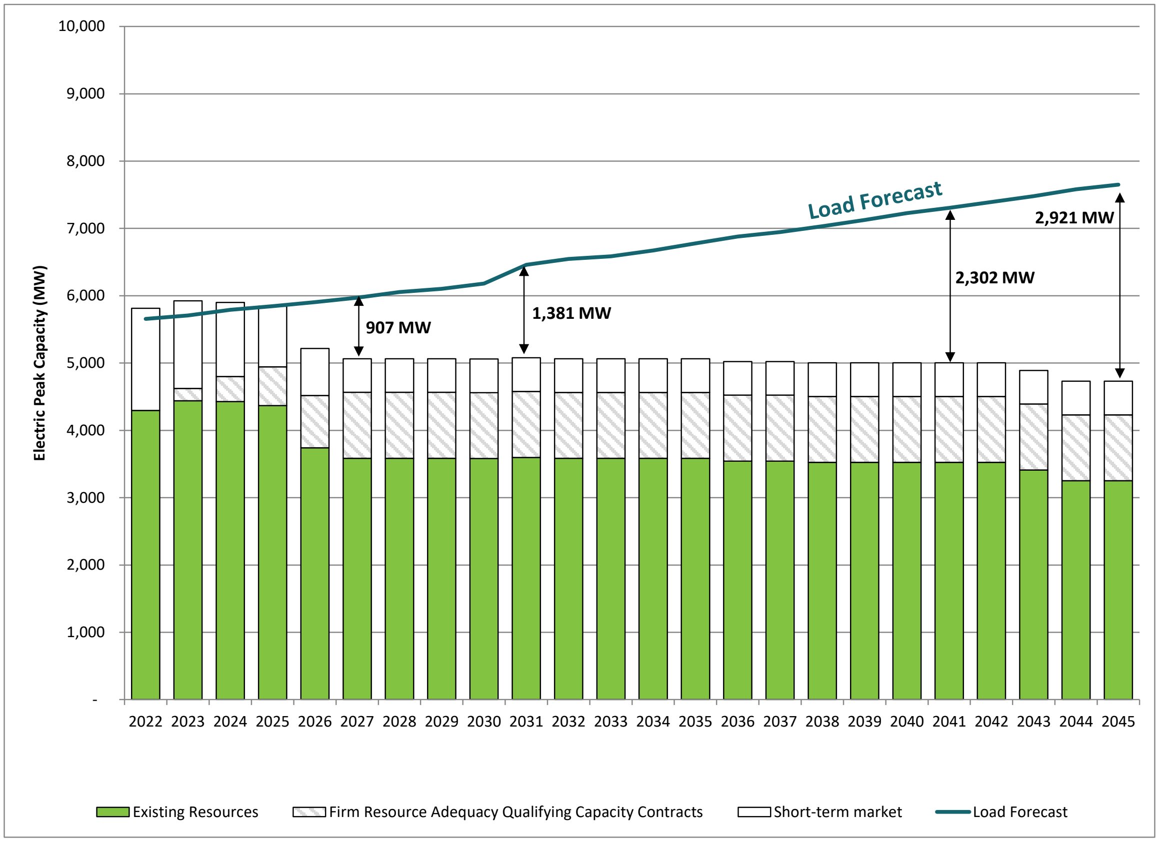
Meeting our customers' needs reliably is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

1. **Peak hour capacity reliability**: PSE must have the capability to meet customers' electricity needs reliably during peak demand hours;
2. **Hourly energy**: PSE must have enough energy available in every hour of the year to meet customers' electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the legal requirements of the Energy Independence Act and the Clean Energy Transformation Act.

Peak Hour Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of exiting coal resources, PSE may begin to experience a peak capacity shortfall starting in 2026. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 907 MW by 2027. The 907 MW is the difference between the load forecast (the demand forecast plus the required planning margin) and the total peak capacity credit of existing resources. Figure 1-1 shows peak capacity need through 2045. After reducing short-term market purchases as discussed in the previous section, the peak capacity need increases to 1,853 MW by the year 2027.

Figure 1-1: Electric Peak Hour Capacity Need

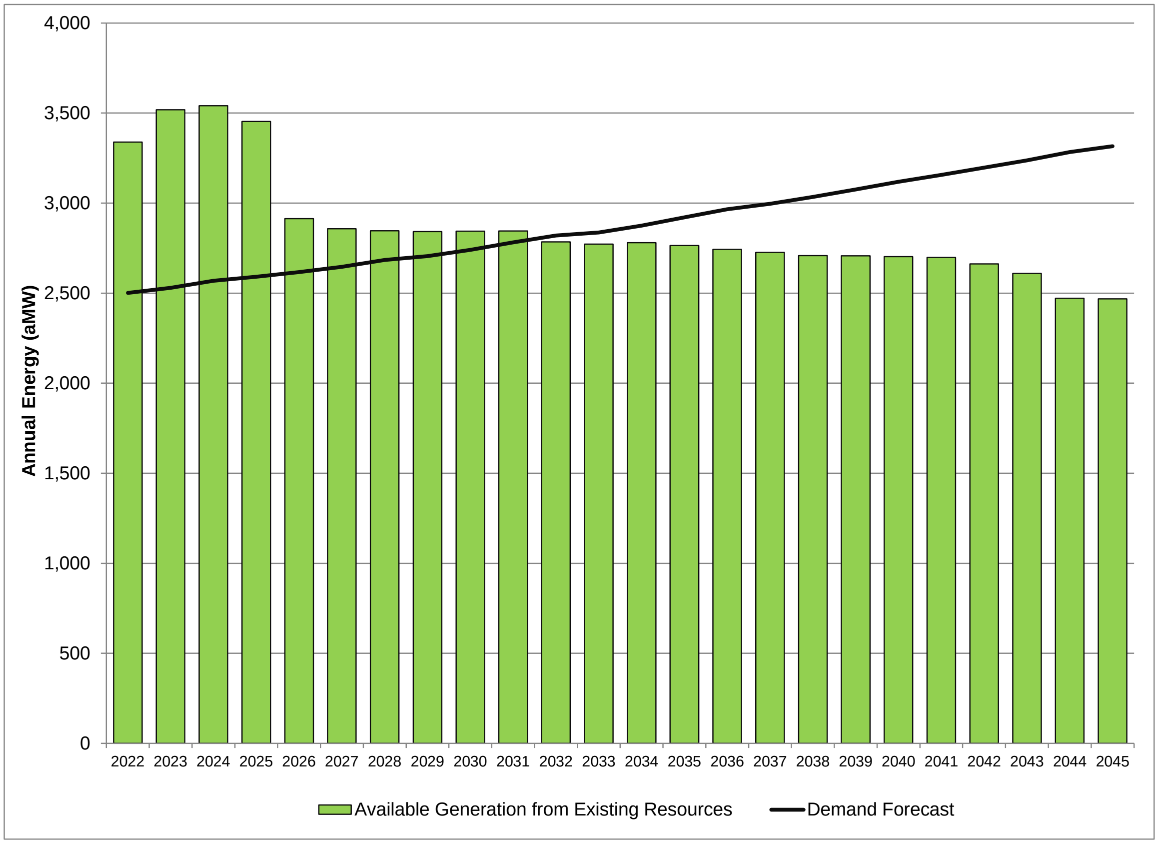


Energy Need

Customer energy needs must also be met in every hour of the year. PSE IRP models require portfolios to supply the amount of energy needed to meet physical loads, and also examine how to do this most economically through existing resources, new resources and purchasing and selling electricity on the energy market. PSE's existing portfolio of supply-side and demand-side resources could generate more energy than needed to meet load on an hourly basis through to 2031; however, it is often more cost-effective to purchase energy from the market than dispatch our existing resources.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the availability of energy resources. This chart does not represent the dispatch of resources or how they will be used to meet PSE's loads, it simply looks at how much energy all the available resources that PSE owns or contracts can potentially generate. For example, PSE's thermal resources are dispatched based on economics, but this chart shows how much energy they could produce if they were run for the entire year. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2031.

Figure 1-2: Annual Energy Position with Energy from All Existing Resources

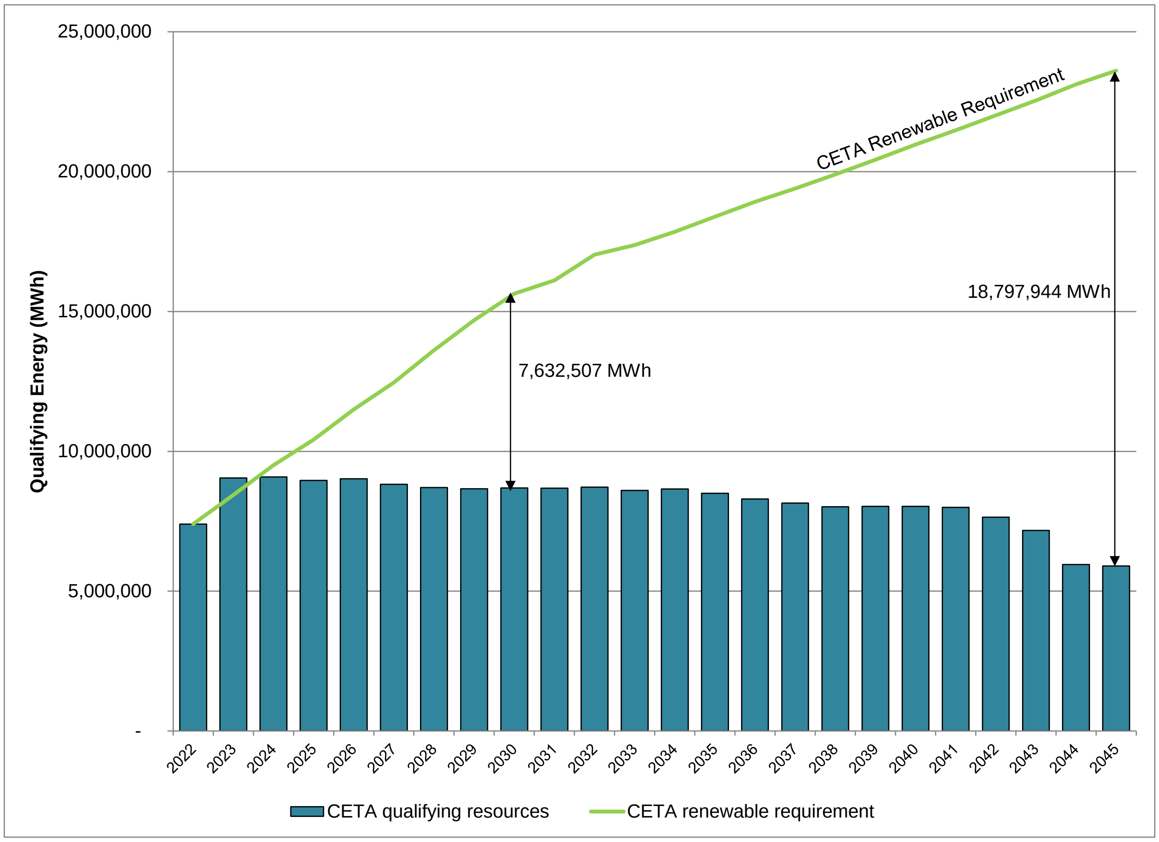


Renewable Energy Need

In addition to reliably meeting the physical needs of our customers, Washington State's Clean Energy Transformation Act (CETA) requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 1-3 illustrates PSE's renewable energy need. For the long-term IRP analysis, a linear ramp to achieve the Clean Energy Transformation Standards in 2030 and 2045 is assumed; however, actual resource acquisitions and the CEIP likely will produce a less linear pathway than shown here. Before any conservation, the renewable energy need is over 7.6 million MWh in 2030. The renewable need is the difference between the green line and the teal bars.

Figure 1-3: Renewable Energy Need



Electric Preferred Portfolio

The IRP preferred portfolio provides a 24-year resource outlook. As explained above, it is not an action plan; rather, it is a forecast of resource additions developed by the modeling that appears most cost effective over the 24-year period given the resource and market trends observed today, while meeting the needs described above and considering customer benefits. Updates will be made every two years and a new long-term IRP analysis will be completed every four years.

The electric preferred portfolio complies with the Clean Energy Transformation Act and is consistent with PSE's beyond net zero carbon goals.

- **ACCELERATED ACQUISITION OF ENERGY CONSERVATION**. The portfolio includes aggressive, accelerated investment in helping customers use energy more efficiently.
- **INCREASED DEMAND RESPONSE**. Compared to previous plans, increased acquisition of demand response appears as a cost-effective resource earlier in the planning horizon. From the 16 demand response programs evaluated in this IRP, 14 were found to be cost effective over the 24-year timeframe.
- **INTEGRATION OF DISTRIBUTED ENERGY RESOURCES**. Distributed energy resources, such as battery energy storage and rooftop and ground-mounted solar, play an important role in mitigating transmission constraints. These resources may also provide non-wire solutions to meeting specific long-term needs identified on the transmission and distribution systems.
- **SIGNIFICANT INVESTMENTS IN RENEWABLE RESOURCES**. Meeting the Clean Energy Transformation Standards will require large amounts of utility-scale renewable resources located both inside and outside of Washington state. This IRP evaluated several wind and solar locations, along with hybrid combinations such as solar plus battery storage, and wind plus battery storage. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest because it makes a higher contribution to peak capacity needs.
- **ADDITIONAL NEED FOR FLEXIBLE CAPACITY**. A large capacity deficit is created when 750 MW of coal is removed from PSE's portfolio in 2026. Renewable resources, distributed energy resources and demand response will contribute to meeting peak hour capacity need, but simple-cycle combustion turbines operated on biodiesel (a CETA complaint fuel) was found to be the most cost-effective way of maintaining system reliability. Given the limited run-time expected of these turbines, it is estimated that existing Washington state biodiesel production could meet the annual fuel supply needs.
- **FIRM RESOURCE ADEQUACY QUALIFYING CAPACITY CONTRACTS.** To reduce exposure to the increasingly supply challenged and volatile wholesale energy market, this

IRP recommends that up to 1,000 MW of PSE's Mid-C transmission should be filled with firm resource adequacy qualifying capacity contracts that meet PSE's reliability requirements for resource adequacy.

Figure 1-4 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 24 years. The preferred portfolio is a diverse mix of demand- and supply-side resources that meet the projected capacity, energy and renewable resource needs described above and considers customer benefits. Incremental resource additions are shown across three time horizons along with the total resource additions for the 24-year planning horizon.

Figure 1-4: Electric Preferred Portfolio, Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage Hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

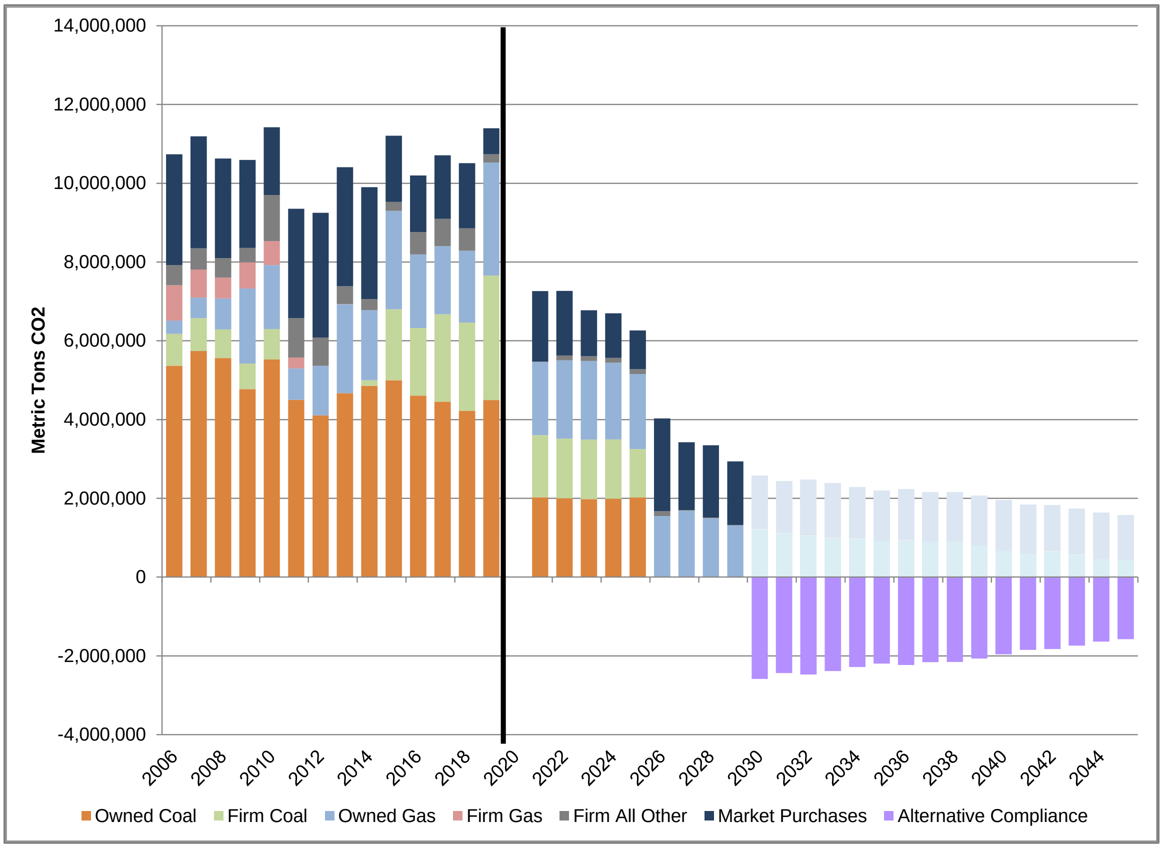
NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace with the growing demand for clean energy. Investments in the delivery system are also needed to deliver energy to PSE's customers from the edge of PSE's territory and support the integration of distributed energy resources and demand response within the delivery grid.

Greenhouse Gas Emissions

PSE's resource plan achieves significant greenhouse gas emission reductions. By 2030, PSE will drastically decrease direct greenhouse gas emissions when Colstrip Units 3 and 4 retire and the coal-transition contract with TransAlta ends, along with a significantly lower economic dispatch of existing fossil-fuel resources. A substantial drop in emissions also occurred at the end of 2019 when Colstrip Units 1 and 2 retired. In 2030, PSE will achieve a carbon neutral electric portfolio through compliance mechanisms which are not yet determined but may include additional renewable resources, energy efficiency, unbundled renewable energy credits or other energy transformation projects. Figure 1-5 shows the reduction in emissions through to the end of the planning horizon.

Figure 1-5: Reduction in PSE Greenhouse Gas Emissions



Electric Short-term Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement reliable programs that put PSE on a path to achieve an additional 53.4 aMW of energy efficiency by the end of 2023 through program savings.

Under the Energy Independence Act (EIA), Utilities must pursue all conservation that is cost-effective, reliable and feasible. They need to identify the conservation potential over a 10-year period and set two-year targets. This 10-year cost-effective savings of 266 aMW divided by 5 is called the pro-rata share, so PSE's draft 2021 EIA target for the 2022-2023 biennium is the 10-year pro-rata share, which is 53.4 aMW. If we were to look at just the 2-year savings from the cost-effective energy efficiency instead of the 10-year pro-rata share, the 2-year energy efficiency saving is only 41.7 aMW.

2. Equity Advisory Group

Convene and engage an Equity Advisory Group to provide guidance from a diversity of voices in the development of PSE's short-term and long-term strategies, initiatives and programs to ensure the equitable distribution of benefits and reduction of burdens to highly impacted communities and vulnerable populations in the transition to clean energy.

3. Mitigate Risk of Short-term Energy Market

Update internal policies for market transaction limits for PSE's Energy Supply Merchant and begin to secure firm resource adequacy qualifying capacity contracts to reduce the risk associated with short-term bilateral energy market purchases.

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

Determine and execute the appropriate resource acquisition strategy to meet the 2021 IRP resource needs with CETA-complaint resources. Ensure that all resources are evaluated across a consistent set of criteria and that appropriate enabling technologies sufficiently address the requirements necessary to support both distributed energy and utility-scale renewable resources.

5. Demand-side Resources: Develop and Issue a Demand Response and Distributed Energy Resources RFP

File a targeted RFP with the Washington Utilities and Transportation Commission no later than November 15, 2021 for both distributed energy resources and demand response resources.

Additional specific actions for the next four years will be developed and communicated in the CEIP. The electric action plan is discussed in further detail in Chapter 2, Clean Energy Action Plan.

4. ELECTRIC RESOURCE PLAN NEXT STEPS

The IRP determines the capacity, renewable and energy resource needs which set the supply-side targets for detailed planning in the Clean Energy Implementation Plan and the resource acquisition process. The CEIP will prescribe four-year targets for resources by adding near-term detail concerning resource assumptions, modeling, sensitivities and costs to PSE's 24-year IRP outlook and Clean Energy Action Plan. These costs may be derived from projects submitted through the RFP process or through other program plans, though this may be challenging in 2021 due to the compressed timeframe of the first CEIP cycle.

The formal Request for Proposal (RFP) resource acquisition processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP should also be considered when making prudent resource acquisition decisions.

CETA adds a new dynamic to resource planning in the form of evaluating and determining equitable distribution of benefits for all customers, specifically in identifying highly impacted communities and vulnerable populations. In developing the CEIP, PSE will also consider the equitable distribution of benefits to customers for the proposed projects and programs, including the equitable distribution of non-energy impacts. The IRP/CEAP includes an assessment of current conditions based on economic, health, environmental, energy security and resiliency, and other metrics, and the CEIP will use the criteria from this assessment in determining the programs and projects to implement over the next four years. The CEIP takes into consideration the mix of resources from the IRP, and applies the layer of customer benefits.

5. NATURAL GAS RESOURCE PLAN

PSE develops a separate integrated resource plan to address the needs of more than 840,000 retail natural gas sales customers. This plan is developed in accordance with the Washington Administrative Code (WAC) 480-90-238, the IRP rule for natural gas utilities. The natural gas sales analysis is described in detail in Chapter 9 and supported by several Appendices.

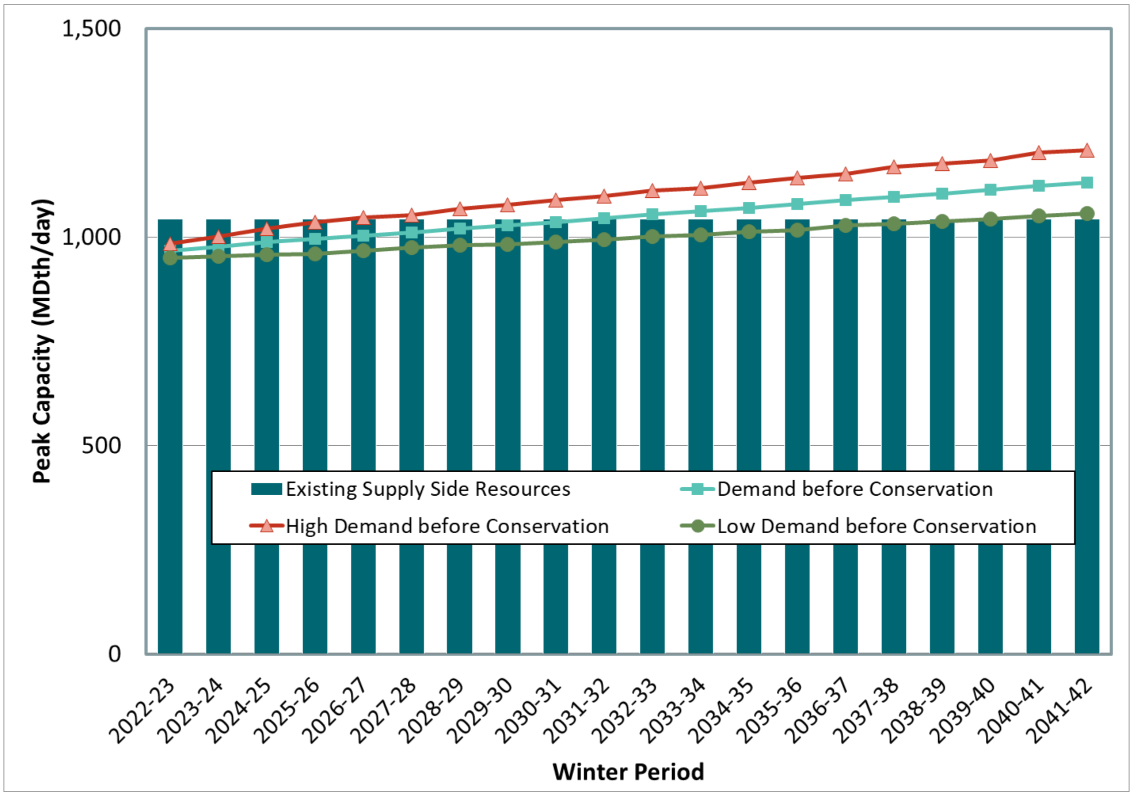
Since most of the natural gas analysis was completed prior to the 2021 Washington State legislative session, it does not include new legislation that may substantially reduce the use of natural gas in certain sectors, if enacted. While the resource plan accounts for uncertainty in demand, costs, regulations and policies, it does not account for a transformative change that could have a drastic impact on the use of natural gas. Any new legislation enacted in the 2021 legislative session that pertains to the natural gas sector will be included in the 2023 natural gas IRP.

PSE already integrates some renewable natural gas (RNG) into the delivery system to decrease carbon emissions, and PSE will continue to look for innovative ways to harvest more RNG. PSE has also begun to evaluate opportunities to partner in testing and learning how hydrogen can be blended into the natural gas system to reduce carbon emissions. This will prepare PSE to leverage the technology as supply increases, cost decreases and the technology matures.

Natural Gas Sales Resource Need

Natural gas sales resource need is driven by design peak day demand. Natural gas service must be reliable every day and the design peak demand drives the need to ensure that PSE plans for meeting firm supply on a 13-degree day. Figure 1-7 illustrates the load-resource balance for the gas sales portfolio. The lines above the bars represent three different demand scenarios analyzed in this IRP, and the bars represent firm natural gas supply. The chart demonstrates PSE has a small resource need beginning in the winter of 2031-2032, where the bars are below the Mid Demand line. Demand is shown prior to conservation since the cost-effective amount of conservation is an optimized result from the natural gas analysis.

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



Natural Gas Sales Resource Additions Forecast

The natural gas resource plan is a forecast of resource additions that look like they will be cost effective in the future given what we know about resource and market trends today. It calls for increased and continued investment in conservation to meet all future peak day capacity needs. Figure 1-8 summarizes the conservation that PSE forecasts to be cost effective in the future in terms of peak day capacity and MDth per day.

Figure 1-8: Natural Gas Resource Plan Forecast

	Cumulative Reduction to Demand (MDth/day)		
	2025-2026	2030-2031	2041-2042
Conservation	21	53	107

Conservation

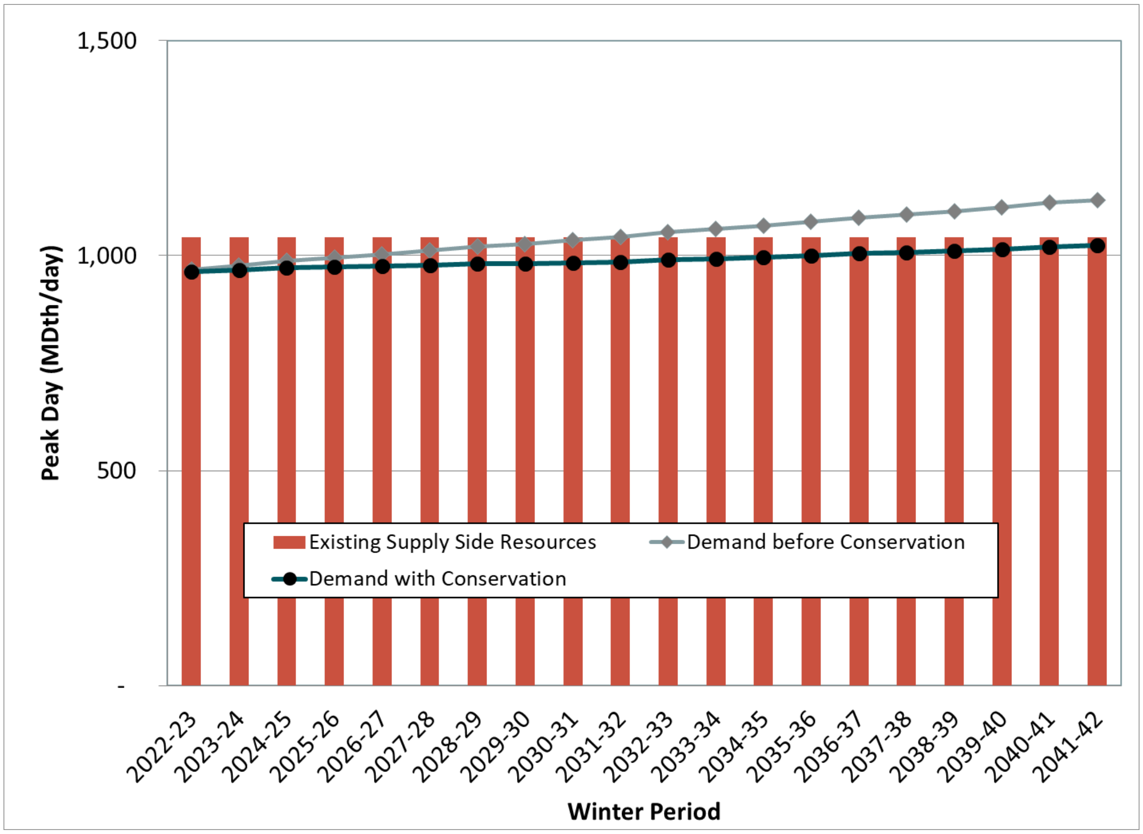
The social cost of greenhouse gases (SCGHG) has a big impact on the amount of cost-effective conservation. In 2019, the state of Washington passed new legislation that requires the inclusion of SCGHG and related upstream carbon emissions in determining cost-effective conservation. When the costs of SCGHG and upstream emissions added to natural gas prices, the resulting total cost is more three times the cost of the natural gas itself. As a result, the cost-effective amount of conservation almost doubles compared to recent energy efficiency savings and current targets, as shown in Figure 1-9.

Figure 1-9: Short-term Comparison of Natural Gas Energy Efficiency

Natural Gas Energy Efficiency	Energy Efficiency over 2-year program (MDth)
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP	1,192

The important role that cost-effective, reliable conservation plays in moderating the need to add supply-side natural gas resources in the future can be seen in the black demand line in Figure 1-10. The bars represent the firm natural gas supply and the two lines above the bars represent natural gas demand with and without conservation.

Figure 1-10: Natural Gas Sales Resource Plan



Natural Gas Sales Short-term 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 12 MDth per day of capacity by 2024 through program savings and savings from codes and standards.

2. Renewable Natural Gas

Meet customer interest in carbon reduction programs through program development and implementation. Evaluate and develop strategies and pursue cost-effective opportunities for renewable natural gas (RNG) acquisition to support voluntary customer RNG programs and future carbon reduction.

3. Emission Reduction Strategy and Planning

Explore potential and voluntary carbon reduction opportunities, and develop and evaluate associated strategies for implementation. Bring the electric and natural gas modeling processes into closer alignment to improve the evaluation of future fuel use for power and the gas-to-electric end-use conversions. Explore the potential for the blending of clean fuels (hydrogen) with existing pipeline infrastructure and customer end use applications. Investigate a range of appliances that may assist with both reducing carbon and helping to ensure natural gas and electric system reliability on peak load days.

2 Clean Energy Action Plan

This chapter describes the 10-year Clean Energy Action Plan for implementing the Clean Energy Transformation Standards.

Contents

1. OVERVIEW

The Clean Energy Transformation Act (CETA) introduced the CEAP as a new aspect of the IRP designed to identify likely action over the next 10 years to meet the goals of CETA. The content of the Clean Energy Action Plan (CEAP) is specifically defined in WAC 480-100-620 subsection 12. This chapter follows the structure defined in subsection 12 and short-term actions are outlined in Chapter 1. This is the first IRP to include a CEAP, and as with any new requirement or assessment, the CEAP will evolve over time, and future IRPs will benefit from the lessons learned in this first implementation of the new planning process.

PSE is committed to achieving the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and CEAP presented here reflects these changes and goals. Specifically, the CEAP provides a 10-year outlook that refines the IRP preferred portfolio. In turn, the CEAP informs the Clean Energy Implementation Plan (CEIP), which develops specific targets, interim targets and actions over a 4-year period per RCW 19.405.060.

2. EQUITABLE TRANSITION TO CLEAN ENERGY

Assessment of Current Conditions

CETA sets out important new planning standards that require utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, PSE performed an Economic, Health and Environmental Benefits (EHEB) Assessment (or "the Assessment") to provide guidance for development of the utility's CEAP and CEIP. The purpose of the Assessment is two-fold: first, to identify highly impacted communities and vulnerable populations within PSE's service territory; and second, to measure disparate impacts to these communities using specific customer benefit indicators.

At the November 2020 IRP meeting, PSE outlined the methodology and proposed customer benefit indicators to be used in the Assessment and solicited stakeholder feedback. This feedback was incorporated into the development of the Assessment, as well as insights gained from the WUTC's December 2020 final rulemaking language and associated adoption order and the February 2021 Cumulative Impact Analysis completed by the Washington Department of Health. A full description of the methods, results and future plans for the Assessment are available in Appendix K.

PSE recognizes the importance of developing a process in which all voices are included and heard, and acknowledges that the IRP public participation process is only the first incremental step in seeking stakeholder feedback on the Assessment. Many populations and communities are not represented in the IRP public participation process. This will be an important part of the evolution of the resource planning process, and PSE anticipates additional engagement through the CEIP public participation process and in future IRP cycles.

The initial qualitative and quantitative customer benefit indicators developed through the Assessment provide a snapshot in time of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE's service territory. Due to the timing of the IRP process and the new CETA regulations, the initial customer benefit indicators included in the CEAP should be viewed as preliminary and likely to change through public participation and input from PSE's Equity Advisory Group. The initial customer benefit indicators will be modified and evaluated over time to measure progress towards achieving an equitable distribution of benefits and reduction of burdens.

Role of the Equity Advisory Group

As part of the CEIP public participation process, PSE is establishing an Equity Advisory Group to provide specific input on the first CEIP, due in October of 2021, as well as on the implementation of that plan. In future planning cycles, the Equity Advisory Group's input will be important to incorporate starting with the planning for the IRP process. This will be an important area of learning and improvement through the entire planning cycle from the IRP through to the CEIP.

Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits in the transition to a clean energy future is to include customer benefit indicators in the preferred portfolio development process. For this IRP, due to the timing of the rulemaking and establishment of the Equity Advisory Group, PSE was only able to incorporate feedback during the IRP public process. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process.

To reflect customer benefit indicators in the development of the preferred portfolio, the customer benefit indicators were first linked to specific portfolio modeling outputs. These outputs were then combined into broader customer benefit indicator areas which provided a context for interpreting the portfolio outputs. Each portfolio from the sensitivity analyses was ranked on how well it performed in each of the customer benefit indicator areas to get an understanding of which benefits or burdens it may confer upon PSE's customers. Portfolios had to score well in several customer benefit indicator areas to be considered a preferred portfolio. The customer benefit indicator framework is described in more detail in Chapters 3 and 8.

In summary, PSE is taking several preliminary actions to ensure that all customers benefit from the transition to clean energy:

1. Establishing the Equity Advisory Group
2. Developing a public participation plan for the CEIP to obtain input on equitable distribution of benefit and burdens
3. Refining customer benefit indicators and metrics with the EAG and the CEIP public participation process
4. Updating the Customer Benefits Analysis to incorporate the customer benefit indicators and related metrics in the CEIP and future IRPs

3. 10-YEAR CLEAN RESOURCE ADDITIONS

10-Year Clean Resource Summary

In alignment with the IRP 24-year outlook, Figure 2-1 below summarizes the 10-year outlook for the resource mix in the preferred portfolio. The customer benefit indicators informed the final selection of resources while also ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs and addressed market risk.

Figure 2-1: 10-year Annual Resource Additions Preferred Portfolio

Resource Type	Incremental Nameplate Resource Additions (MW)										Total (MW)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Distributed Energy Resources											
Demand-side Resources											
Energy Efficiency	36	39	41	42	44	47	50	50	54	56	458
Distributed Generation – Solar PV	0.2	0.4	0.7	1.2	2.1	3.6	6.1	10	16	18	58
Distribution Efficiency	1.2	0.3	0.7	1.8	1.2	1.3	1.3	1.3	1.3	1.3	12
Codes & Standards	37	24	19	12	15	14	25	13	4	6	169
Total Demand-side Resources	74	64	61	57	63	66	82	75	75	81	696
Battery Energy Storage	-	-	-	25	25	25	25	25	50	25	200
Solar - ground and rooftop	-	-	-	80	30	30	30	30	30	30	260
Demand Response	-	5	6	18	27	34	40	27	26	13	196
DSP Non-wire Alternatives	3	6	9	4	3	5	6	5	4	4	50
Total Distributed Energy Resources	78	75	75	184	148	160	183	161	185	153	1,402
Renewable Resources											
Wind	-	-	-	400	200	400	-	200	200	100	1,500
Solar	-	-	-	-	-	100	-	100	198	0	398
Total Renewable Resources	-	-	-	400	200	500	-	300	398	100	1,898
Peaking Capacity with Biodiesel	-	-	-	-	255	-	-	-	-	-	255
Firm Resource Adequacy Qualifying Capacity Contracts	-	185	187	202	202	203	-	-	-	-	979

Conservation Potential Assessment

Demand-side resource (DSR) alternatives are analyzed in a Conservation Potential Assessment and Demand Response Assessment (CPA) to develop a supply curve that is used as an input to the IRP portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings that can potentially be captured without raising the overall electric portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio. The full assessment is included in Appendix E.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP. While the IRP evaluates demand-side resources through the CPA process, the CEIP will establish the specific targets for renewable energy, energy efficiency and demand response, and may evaluate programs aligned with those targets.

- **ENERGY EFFICIENCY MEASURES.** This includes a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, lighting upgrades and appliance upgrades.
- **DEMAND RESPONSE (DR).** Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility’s supply cost. The achievable technical potential for demand response was assessed through the CPA, and the cost-effective demand response programs identified in this IRP are described in a separate section below.
- **DISTRIBUTED GENERATION.** Distributed generation refers to small-scale electricity generators located close to the source of the customer’s load on customer’s side of the utility meter. The CPA identifies combined heat and power (CHP) and customer-owned rooftop solar as distributed generation. Other distributed energy resources are also evaluated in this IRP and described in a separate section below.
- **DISTRIBUTION EFFICIENCY (DE).** Distribution efficiency addresses conservation voltage reduction (CVR), which is the practice of reducing the voltage on distribution circuits to reduce energy consumption, since many appliances and motors can perform properly while consuming less energy. Phase balancing is required for CVR to eliminate total current flow energy losses.
- **CODES AND STANDARDS (C&S).** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. Only those in place at the time of the CPA study are included.

Figure 2-2 shows the achievable technical potential of demand-side resource savings in PSE's service territory. The year 2031 savings represent the 10-year potential starting in 2022.

Figure 2-2: 10-year Achievable Technical Potential Demand Side Resource Savings

Demand-Side Resources	Nameplate 2031	Energy Savings 2031	Peak Capacity Savings 2031
Energy Efficiency	458 MW	263 aMW	458 MW
Distributed Generation: Solar PV	58 MW	7 aMW	0 MW
Distribution Efficiency	12 MW	11 aMW	12 MW
Codes and Standards	169 MW	93 aMW	177 MW
Total Achievable Technical Potential	696 MW	374 aMW	646 MW

NOTES
1. Demand response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency.
3. Given the nature of the IRP, assumptions for the models need to be set months before the IRP is finalized. This is simply of forecast of best known information at the time. Some of these forecast may have changed since the IRP inputs were finalized.

The IRP analysis evaluates the amount of demand-side resources (conservation) that is cost effective to meet the portfolio's capacity and energy needs, optimizing lowest cost and considering both distributed and centralized resources. The final analysis indicates that although current market power prices are low, accelerating the acquisition of DSR continues to be a least-cost strategy to meet renewable requirements. CETA renewable requirements result in significant increases in avoided cost, and this impacts the amount of cost-effective DSR. The large amounts of renewable resources needed to meet CETA move higher cost demand-side resources into the portfolio because conservation reduces load, thereby reducing the amount of renewable resources needed to meet requirements. Figure 2-3 shows the cost-effective amount of demand-side resources identified in the IRP by category (energy efficiency, customer solar PV forecast, distribution efficiency and codes and standards).

Figure 2-3: Cost-effective Demand-side Resources Incremental Nameplate Additions

Demand-Side Resources	Incremental Nameplate Additions		10-year Total
	2022-2025	2026-2031	
Energy Efficiency	157 MW	301 MW	458 MW
Distributed Generation: Solar PV	2 MW	56 MW	58 MW
Distribution Efficiency	4 MW	8 MW	12 MW
Codes and Standards	92 MW	77 MW	169 MW
Total Demand-side Resources	256 MW	440 MW	696 MW

NOTES
1. Demand Response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency. Additional distributed energy resources were evaluated in this IRP and are described below.

Resource Adequacy

PSE has established a 5 percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. LOLP measures the *likelihood* of a load curtailment event occurring in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s). Therefore, the likelihood of capacity being lower than the load, occurring anytime in the year, cannot exceed 5 percent.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE's resources with those of other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and the availability of supply-side resources. A full description of the peak capacity and ELCC values is in Chapter 7.

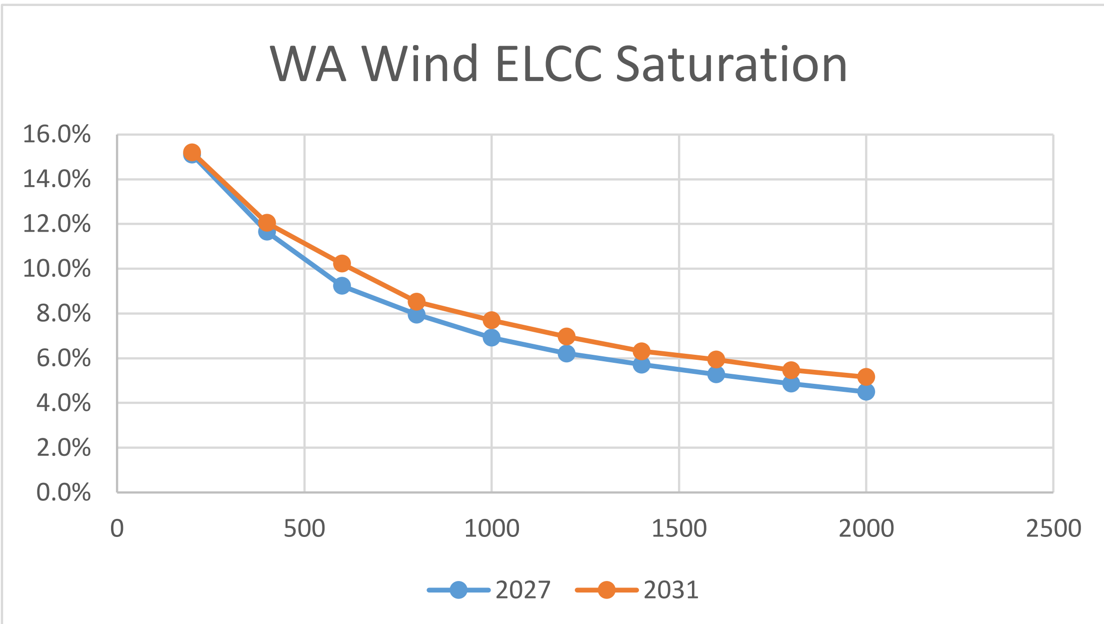
Figure 2-4 shows the estimated peak capacity credit or ELCC of the wind and solar resources included in this IRP. The order in which the existing and prospective projects were added in the model follows the timeline of when these projects are acquired or about to be acquired. The concept of resource saturation is also important to the ELCC calculation. Each incremental resource added in the same geographical area provides less effective peak capacity because it provides more of the same resource profile rather than increasing the diversity of the resource profile. The ELCC calculation for the first 100 MW of the resource is shown below in Figure 2-4, and the full saturation curve for up to 2,000 MW of Washington wind and solar is shown in Figure 2-5.

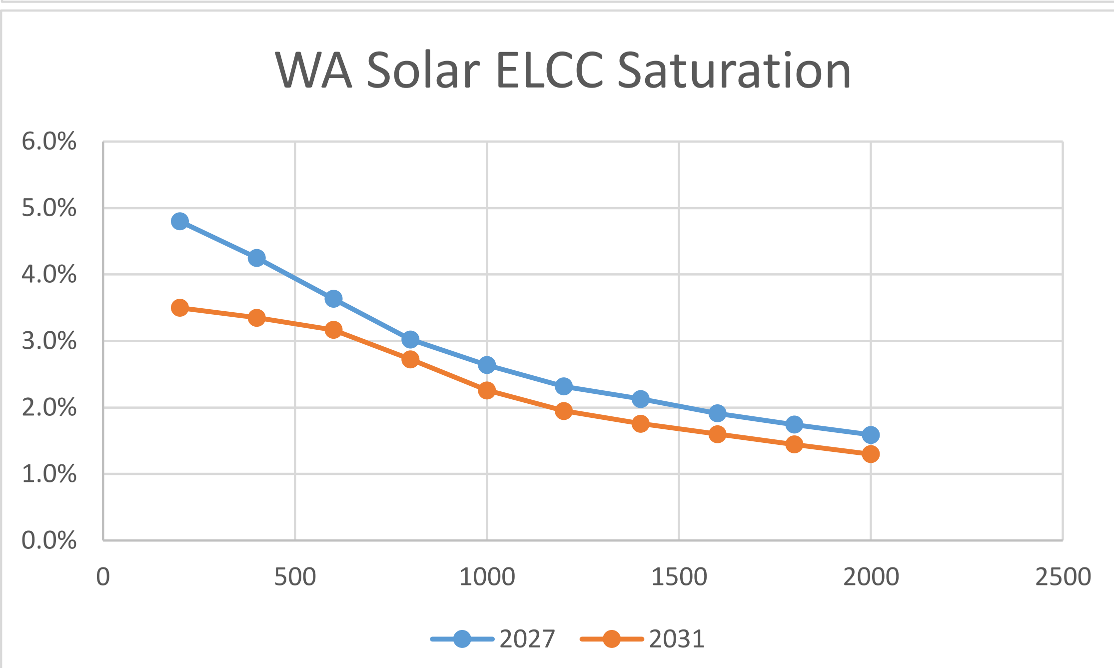
Figure 2-4: Peak Capacity Credit for Wind and Solar Resources

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar	100	4.0%	3.6%
Generic WA West Solar – Utility scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

ELCC SATURATION CURVES. The table above shows the peak capacity credit for the first 100 MW of installed nameplate capacity for Washington state wind and solar. Below, Figure 2-5 plots the peak capacity credit for the next 200 MW and then the next 200 MW after that and so on, showing how the peak capacity credit decreases as more wind or solar is added in the same region. Wind or solar nameplate capacity is shown in MW on the horizontal axis, and peak capacity credit as a percent of nameplate capacity is shown on the vertical axis.

Figure 2-5: Saturation curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak capacity credit of two types of batteries were modeled as well as pumped storage hydro. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. Figure 2-6 shows the peak capacity credit of the types of storage resources modeled in the IRP. The peak capacity credit for battery storage is low because batteries are relatively short-duration resources. Unlike generating resources, battery storage resources have to recharge; therefore, when long-duration needs for energy occur as in winter peaks, batteries provide little contribution compared to generating resources. Longer duration storage resources provide higher peak capacity credits.

Figure 2-6: Peak Capacity Credit for Energy Storage

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

DEMAND RESPONSE CAPACITY CREDIT. The estimated peak capacity credit of demand response is shown in Figure 2-7.

Figure 2-7: Peak Capacity Credit for Demand Response

DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Wholesale Electric Market Risk

The wholesale electric market has changed significantly in recent years and is now experiencing tighter supply and increasing price volatility. As a result, regional power suppliers, including PSE, are making changes to how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility-by-utility, has the potential to increase reliability for all providers in the region, and as a result, numerous regional entities, including PSE, are collectively developing a regional resource adequacy program. At this time, the program has not been included in the IRP analysis because sufficient details are not yet known. However, it is important that PSE takes appropriate steps in its resource planning to allow for future participation in a regional resource adequacy program once established.

For this IRP, PSE conducted a market risk assessment to evaluate the use of its 1,500 MW of firm transmission to the Mid-Columbia market hub with short-term energy purchase agreements. . The assessment resulted in a recommendation that part of PSE's Mid-C transmission be dedicated to firm resource adequacy qualifying capacity contracts to ensure reliable service. The recommendation includes limiting the amount of real-time, day-ahead and term market purchases and replacing a portion of those energy contracts with firm resource adequacy qualifying capacity contractual arrangements to meet PSE's resource adequacy requirements as well as those of a future regional resource adequacy program. PSE has a strong preference for clean resources and contractual arrangements.

Ensuring Resource Adequacy

PSE must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources and demand response, contribute to meeting the capacity needs of PSE's customers, but they make different kinds of contributions. This IRP determined that the limited-run use of simple-cycle combustion turbines (peakers) operated on biodiesel (a CETA complaint fuel) is the most cost effective means of ensuring resource adequacy. Chapters 3, 5 and 8 describe the numerous clean resource combinations PSE analyzed as an alternative to the biodiesel peaker solution and the significant increases in portfolio costs that resulted. Figure 2-8 summarizes the capacity needed to meet reliability requirements across the first ten years of the planning horizon. The recommended approach from the market risk assessment is also included and shown as firm resource adequacy qualifying capacity contracts.

Figure 2-8: Capacity Additions to meet Reliability

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Peaking Capacity with Biodiesel	0 MW	255 MW	255 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	979 MW

Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times requesting them to reduce their energy use. Some program types require action by the customer, others can be largely automated. For example, an automated program might warm a customer's home or building earlier than usual with no action required. In a program that requires customer action, a wastewater plant may be asked to curtail pumping during certain peak energy need hours if they can operationally do so. Because customers can always opt out of an event, demand response programs include some risk. If PSE is relying on a certain amount of load reduction from demand response to handle a peak event but customers opt out, then PSE must use generating resources to fill the customer's needs.

Demand response programs modeled for this IRP are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral Demand Response

Figure 2-9 lists the estimated achievable technical potential for all winter demand response programs modeled for the residential, commercial and industrial sectors in this IRP. The table shows the achievable potential of each demand response program in MW and the percentage of winter peak need it fills to illustrate the total potential impact of demand response on system peak. The winter percent of system peak load was calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019. The total demand response nameplate achievable potential is 228 MW. The peak capacity credit of demand response programs is shown above in Figure 2-7. Further details about demand response programs modeled in this IRP can be found in Appendix D and E. The program costs shown include a transmission and distribution (T&D) benefit that reflects the value of the program to the distribution system non-wires alternatives. Some programs have a negative cost because the benefits they deliver are greater than their cost to the system.

Figure 2-9: Demand Response Achievable Potential and Levelized Cost by Product Option

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-Auto DR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

This IRP evaluated 16 different demand response programs and 14 of those were found to be cost effective. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate capacity by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers; by 2031, this grows to 196 MW. Figure 2-9 summarizes the cost-effective demand response nameplate capacity.

Figure 2-9: Cost-effective Demand Response Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Demand Response	29 MW	167 MW	196 MW

Renewable Resources

For this IRP, wind was modeled in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and off the coast of Washington. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States.

Energy storage resources were modeled separately and in combination with the renewable resources. Two battery storage technology systems were 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. Pumped storage hydro resources were also analyzed. These are generally large, on the order of 250 to 3,000 MW, and the analysis assumes PSE would split the output of a pumped storage hydro project with other interested parties. PSE analyzed an 8-hour pumped storage hydro resource and modeled the project in 25 MW increments. In addition to standalone generation and energy storage resources, PSE modeled hybrid resources that combine two or more resources at the same location to take advantage of synergies between the resources. Three types of hybrid resources were modeled: eastern Washington solar plus 2-hour lithium-ion battery, eastern Washington wind plus 2-hour lithium-ion battery and Montana wind plus pumped storage hydro.

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources from the Pacific Northwest region may be limited. The timing of renewable resource additions is driven by CETA renewable requirements and is shown in Figure 2-10 below. Hybrid resources were shown to be cost effective later in the planning horizon so they are not shown in the first ten years.

Figure 2-10: Renewable Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Wind Resources	400 MW	1,100 MW	1,500 MW
Solar Resources	-	398 MW	398 MW
Total Renewable Resources	400 MW	1,498 MW	1,898 MW

Distributed Energy Resources

While the adoption of distributed energy resources (DER) is still low in PSE's service territory, about 1 percent of PSE customers are participating in net-metered solar, with an installed capacity of approximately 85 MW. As DER technology evolves and prices decline, customer adoption will likely increase. DERs will play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs. To accomplish this, PSE will file a draft targeted RFP with the WUTC no later than November 15, 2021 for both distributed energy resources and demand response resources, consistent with Order 05 in Docket UE-200413.

In this IRP, PSE specifically included several different types of distributed energy resources. In addition, demand response, which is considered a distributed energy resource, was also modeled in this IRP as discussed above.

BATTERY ENERGY STORAGE. Two distributed battery storage technology systems were analyzed: lithium-ion and flow technology. These battery storage 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 or on the distribution system, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour and 4-hour lithium-ion batteries and 4-hour and 6-hour flow battery systems.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop and ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington.

NON-WIRES ALTERNATIVES. The role of DERs in meeting delivery system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs, and they can be deployed across both the transmission and distribution systems, providing some flexibility in how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

Figure 2-11 shows the battery energy storage, solar and non-wire alternatives distributed energy resources.

Figure 2-11: Distributed Energy Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Battery Energy Storage	25 MW	175 MW	200 MW
Solar	80 MW	180 MW	260 MW
Non-Wire Alternatives	22 MW	28 MW	50 MW
Total Distributed Energy Resources	127 MW	383 MW	510 MW

4. DELIVERABILITY OF RESOURCES

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona) and in California. The specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment are described in detail in Appendix J. The 10-year delivery system plan is described in Appendix M.

Investments in the delivery system are needed to deliver energy to PSE's customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix M identifies work that is needed to ensure safe, reliable, resilient, smart and flexible energy delivery to customers, irrespective of resource fuel source. These include specific upgrades to the transmission system to meet NERC compliance requirements and other evolving regulations related to DER integration and markets and to the distribution system to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost for interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. The key investment areas are summarized below.

Visibility, Analysis, and Control

Data availability, integrity and granularity are critical aspects to planning for and operating DERs. Through PSE's ongoing investment in Advanced Metering Infrastructure (AMI) and SCADA at distribution substations, PSE will have new data and visibility that can be utilized for delivery system planning, customer program planning and operational analytics. AMI is an integrated system of smart meters, communications networks and data management systems that enables two-way communication between utilities and customers. AMI meters will serve to provide significant enhancements to the types and granularity of data PSE can collect to proactively plan for growth, integrate new technologies, offer services to customers, respond more quickly to system needs and operate the system safely. PSE is currently implementing an Advanced Distribution Management System (ADMS). ADMS is a computer-based, integrated platform that provides the tools to monitor and control our distribution network in real time. The implementation of ADMS will ultimately lead to advanced operational capabilities for DERs including an integrated Distributed Energy Resource Management System (DERMS). Prior to implementation of a fully integrated DERMS, PSE anticipates the need for a virtual power plant (VPP). Virtual power plants forecast and aggregate different types of DERs in order to coordinate dispatch to meet system resource needs. VPPs can aggregate DERs including demand response, EV charging management, CHP, solar PV (smart inverters) and distributed storage. Some VPPs can also manage alternative pricing programs such as Peak Time Rebates. In order to realize the dispatchable capacity benefits of the DER additions expected over the next 5 years, PSE needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. PSE will develop the technical and operational requirements for a VPP platform in mid-2021. In addition to AMI and ADMS, SCADA provides real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility and enhance overall reliability of the distribution system.

PSE also recognizes the importance of maintaining and augmenting the data that we already have, particularly the asset data within our Geographic Information System (GIS). PSE is working to evolve GIS processes so that changes in the field can be quickly incorporated and so that data such as DER asset information is collected and displayed. GIS connects with many enterprise systems, and GIS data will be increasingly central to the ability to plan for and operate DERs. Finally, data analytics programs will support optimization of customer service and system operations including predicting asset replacement needs before failure as DERs are added to the grid.

PSE also plans to implement a geospatial load forecasting tool that includes DER forecasting capabilities as well as end-use forecasting information that supports our energy efficiency and demand response programs. With this tool we can understand not only the anticipated growth of DERs, but also the specific feeder locations. This will enable proactive system investments and potentially uncover targeted demand-side management options and support non-wires alternatives. PSE will continue to enhance its modeling tools and capabilities to ensure grid stability.

Reliability and Resiliency

To avoid reactive investments due to unanticipated DER adoption and integration and in addition to the work already described, PSE will pursue targeted, proactive asset management and system upgrades to enable DER integration and transportation electrification through ensuring a healthy system, managing load and DERs, and ensuring reliable operation. Grid modernization investments will improve the reliability of PSE systems, improve their ability to withstand and recover from extreme events, and enable smart and flexible grid capabilities. Ongoing and site-specific asset investments are needed such as pole replacement, tree-wire conductor and cable remediation programmatic transformer replacements as DERs and electric vehicles propagate, and substation and circuit enhancements that ensure or expand DER effectiveness.
Managing increasing loads will be intentional with advanced capabilities such as Volt-Var Optimization (VVO) and enabling faster system outage restoration through use of Fault Location, Isolation Service Restoration (FLISR), all enabled through the ADMS platform and additional investments in reclosers, switches, voltage regulators, capacitors banks and network communications infrastructure. FLISR will support grid reliability to enable battery energy storage charging and transportation electrification. VVO will manage voltage and reactive power as loads shift due to DER implementation.

PSE will also pursue energy security and resiliency investments such as microgrids or infrastructure hardening where specific locations require increased resilience. These locations could include highly impacted communities, transportation hubs, emergency shelters and areas at risk for isolation during significant weather events or wildfires.

DER Integration Processes

In addition to the enabling technologies, analytical capabilities and system component upgrades, PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for both customers and developers by prescreening applications. Additional customer tools, such as modifications to billing systems and program administration and design, may be needed as PSE's operating model moves from traditional one-way power flow to two-way energy flow and delivery. PSE continues to integrate non-wire alternative analysis in developing investment plans to meet various energy needs of our customers.

Security, Cybersecurity and Privacy

While pursuing our grid modernization strategy, PSE will continue to put a strong focus on cyber-security. PSE applies the same level of due diligence across the enterprise to ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape. PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. As critical infrastructure technology becomes more complex, it is even more crucial for PSE to adapt and mature cyber-security practices and programs allowing the business to take advantage of new technical opportunities such as Internet of Things (IoT) devices. In addition, we continue to foster strong working relationships with technology vendors to ensure their approach to cyber-security matches PSE's expectations and needs.

Backbone Infrastructure Projects

Finally, PSE will continue to upgrade its local transmission system in order to meet NERC compliance requirements and evolving regulations related to DER integration and markets and meet peak demand reliably. PSE will deploy identified, project-specific non-wires solutions to support the near-term integration of DERs and continue to validate the DER forecast to realize predicted solutions to meet resource needs.

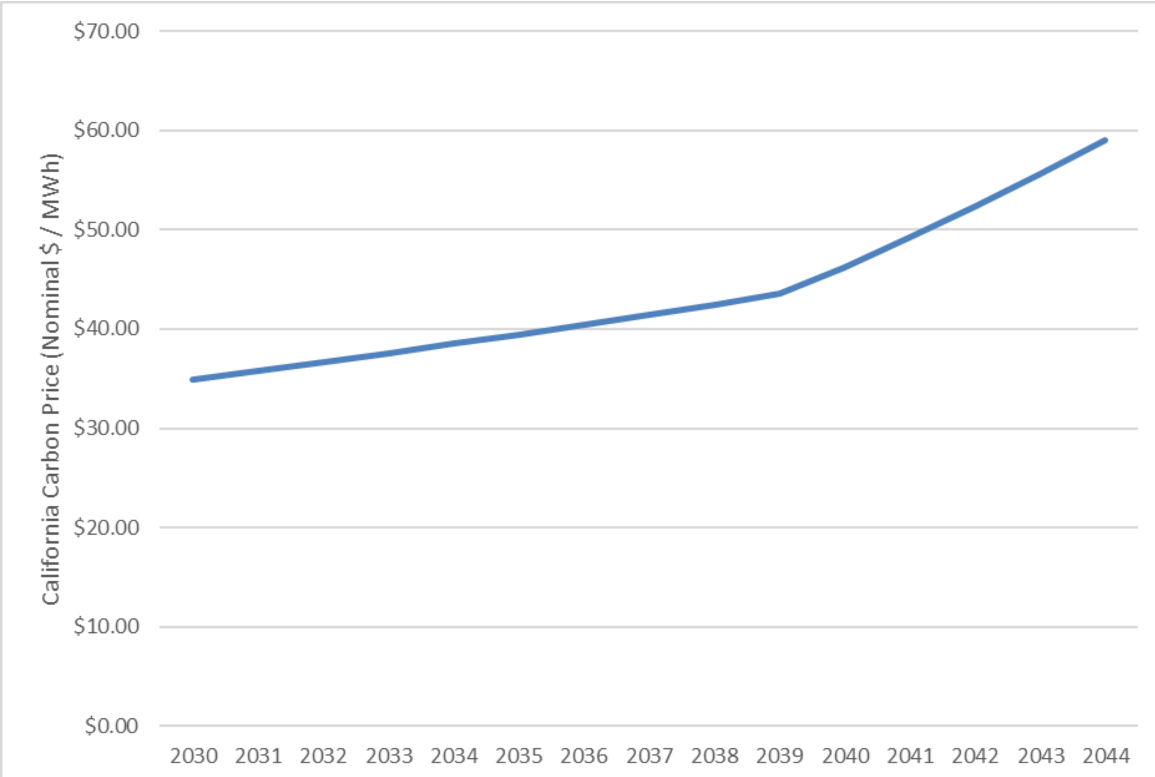
5. ALTERNATIVE COMPLIANCE OPTIONS

Under CETA, up to 20 percent of the 2030 greenhouse gas neutral standard can be met with an alternative compliance option. These alternative compliance options can be used beginning January 1, 2030 and ending December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment in an amount equal to the administrative penalty
- purchasing unbundled renewable energy credits
- investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission

In this IRP, PSE evaluated two alternative compliance options. For the first option, PSE assumed that unbundled renewable energy credits would be purchased for 20 percent of load not met by renewable generation starting in 2030 and decreasing linearly to zero in 2045. Because there is no a transparent forecast of the future price of unbundled renewable energy credits, PSE used the California carbon price as a proxy, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2044 as shown on Figure 2-12. The costs are included in all the portfolios as part of meeting the 2030 standard and in the preferred portfolio.

Figure 2-12: California Carbon Price Forecast (nominal $ per MWh)



In addition to using carbon prices as a proxy price for unbundled renewable energy credits, PSE also wanted to understand the impact of meeting the 20 percent of load with renewable resources such that 100 percent of PSE's load is met with renewable resources by 2030. PSE modeled two ways of meeting this requirement; with battery energy storage and with pumped storage hydro. The total 24-year NPV of this compliance option is $32 billion with batteries and $66 billion with pumped storage hydro. The costs of these two portfolios are between $16 billion and $50 billion higher than the preferred portfolio. Chapter 8 describes these portfolios in detail in Sensitivity N.

Actual compliance may be met through other mechanisms that are still under development and will be determined in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. PSE will analyze these mechanisms as the Department of Ecology develops guidance on methods for assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

6. SOCIAL COST OF GREENHOUSE GASES

The social cost of greenhouse gases (SCGHG) is applied as a cost adder in the development of the electric price forecast and in the portfolio modeling process when considering resource additions. The SCGHG is not included in the final dispatch of resources because it is not a direct cost paid by customers. CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resources options. The SCGHG cost adder is included in planning decisions as part of the fixed operations and maintenance costs of that resource, but not in the actual cost and dispatch of any resource. A SCGHG adder is also applied to the unspecified market purchases.

The SCGHG in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists CO_2 prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from $69 per ton in 2020 to $189 per ton in 2045. Further details can be found in Chapter 5.

3 Resource Plan Decisions

This chapter summarizes the reasoning for the additions to the electric and natural gas resource plans and demonstrates how the electric resource plan meets the clean energy transformation standards.

Contents

1. OVERVIEW

The preferred portfolio is the outcome of robust IRP analyses developed with stakeholder input. It meets the requirements of the Clean Energy Transformation Act and is informed by deterministic portfolio analysis, stochastic portfolio analysis and the Customer Benefit Analysis. The preferred portfolio is a new requirement in the IRP, and this first preferred portfolio marks a significant shift in PSE’s resource direction since the 2017 IRP. The preferred portfolio focuses on clean resources to meet CETA requirements, as well as increases in distributed energy resources.

To support the portfolio analysis to arrive at the preferred portfolio, three distinct types of analysis are used. Deterministic portfolio analysis solves for the least cost solution and assumes perfect foresight about the future. The stochastic analysis assesses the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages. The Customer Benefit Analysis incorporates the equitable distribution of burdens and benefits into the resource planning process. All three of these analytic methods are used to identify and evaluate the preferred portfolio.

Further information on the analyses discussed here can be found in Chapters 5, 6, 7, 8, 9 and the Appendices.

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 3-1 summarizes the forecast of resource additions to the preferred electric portfolio. This portfolio prioritizes cost-effective, reliable conservation and demand response, and distributed and centralized renewable and non-emitting resources at the lowest reasonable cost to our customers. It reduces direct PSE emissions by more than 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments and projected compliance options. While implementing this highly decarbonized portfolio, the portfolio maintains the reliability required with the addition of flexibility capacity starting in 2026.

Figure 3-1: Electric Preferred Portfolio,
Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

Compliance with Clean Energy Transformation Standards

Electric utilities must meet the clean energy standards set by CETA at the lowest reasonable cost. In addition, safety, reliability and the balancing of the electric system must be protected, and electric utilities must ensure that all customers are benefiting from the transition to clean energy.

The clean energy transformation standards state that:

1. On or before December 31, 2025, each utility must eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers;
2. By January 1, 2030, each utility must ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral; and
3. By January 1, 2045, each utility must ensure that non-emitting electric generation and electricity from renewable resources supply 100 percent of all retail sales of electricity to Washington electric customers.

CETA also contains an incremental cost of compliance mechanism that can be used for compliance purposes. In this IRP, PSE does not rely on the incremental cost of compliance mechanism to comply with CETA. All clean energy transformation standards are met with new resources.

MEETING CETA 2025 REQUIREMENTS. Colstrip is removed from PSE's electric supply portfolio by the end of 2025 and replaced with a combination of renewable resources, conservation, demand response, battery energy storage and a simple-cycle combustion turbines (a frame peaker) operated on biodiesel. Biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests is a CETA-compliant renewable resource; all new peaking resources modeled in this analysis are operated with biodiesel fuel, and it is the only fuel used for new peaking resources in the preferred portfolio. The October 2020 U.S. Department of Energy report on alternative fuel prices calculated the price of B99/B100 biodiesel for the west coast at $3.88/gallon.[1] PSE currently operates several peaking plants that can run a back-up fuel (distillate fuel oil) and therefore has experience with storage and transportation for diesel fuels. Given the limited run-time expected of the new turbines, the IRP analysis estimates that existing Washington state biodiesel production could meet new peaking resource fuel supply needs.

1 / Clean Cities Alternative Fuel Price Report, October 2020 (energy.gov)

MEETING CETA 2030 REQUIREMENTS. The preferred portfolio achieves 100 percent greenhouse gas neutrality by 2030 through coal plant retirements in 2025 and by replacing most of the energy produced by existing natural gas plants with renewable resources and projected alternative compliance options. The preferred portfolio meets 80 percent of sales with renewable resources by 2030 and the remaining 20 percent with clean investments and projected compliance options. The projected 20 percent alternative compliance is included as an additional cost starting in 2030.

Figure 3-2 shows the emissions by resource type for the preferred portfolio. There is a direct relationship between emissions and the dispatch of thermal resources. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will further decline with a projected lower economic dispatch of thermal resources and the exit of Colstrip 3 & 4 and Centralia from the PSE portfolio. The retirement of resources and forecasted drop in dispatch decreases the total portfolio emissions by more than 70 percent from 2019 to 2029. Through projected compliance mechanisms, the portfolio achieves carbon neutrality starting in 2030 through to 2045.

PSE also evaluated the costs associated with achieving 100 percent renewable resources by 2030. Reducing emissions and even achieving a 100 percent renewable portfolio by 2030 is possible with existing technologies, but the cost to do so is high. The massive investment in energy storage required to replace thermal resources results in portfolio costs that are $16 billion to $50 billion higher than the preferred portfolio.

Figure 3-2: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions

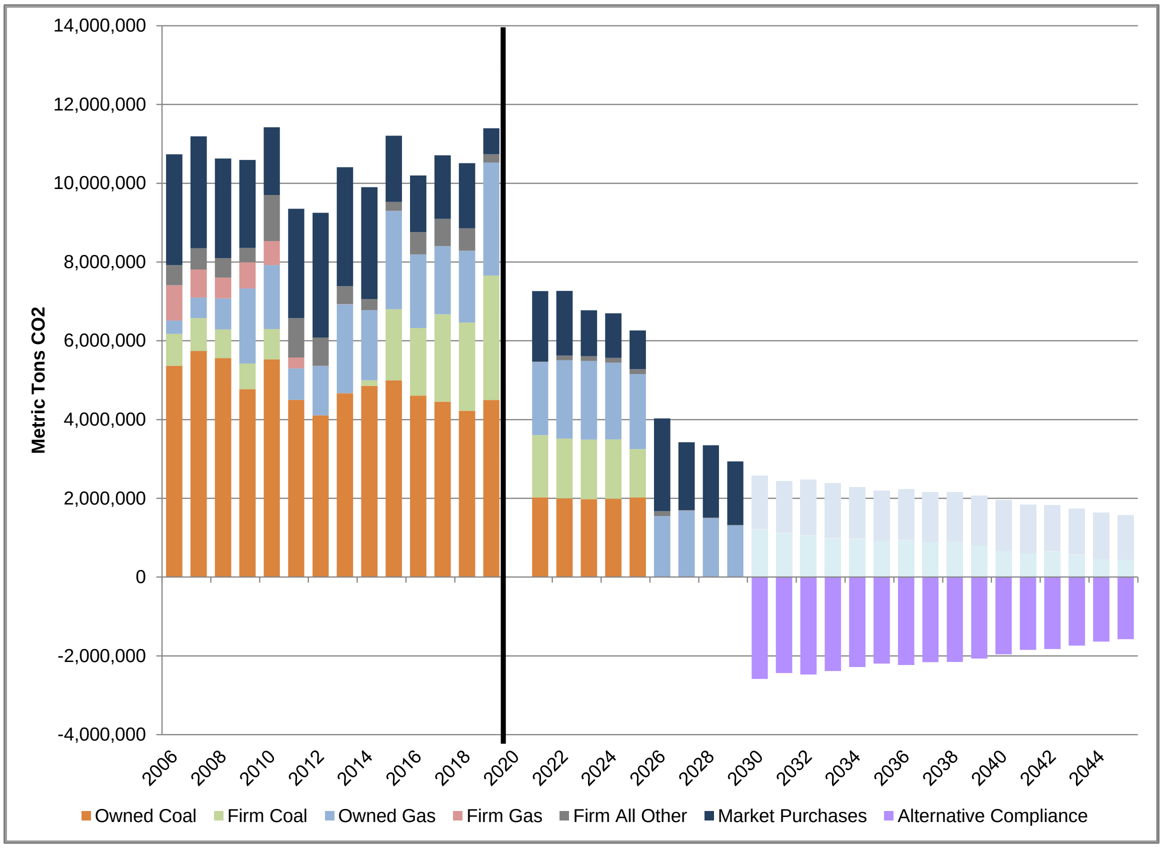
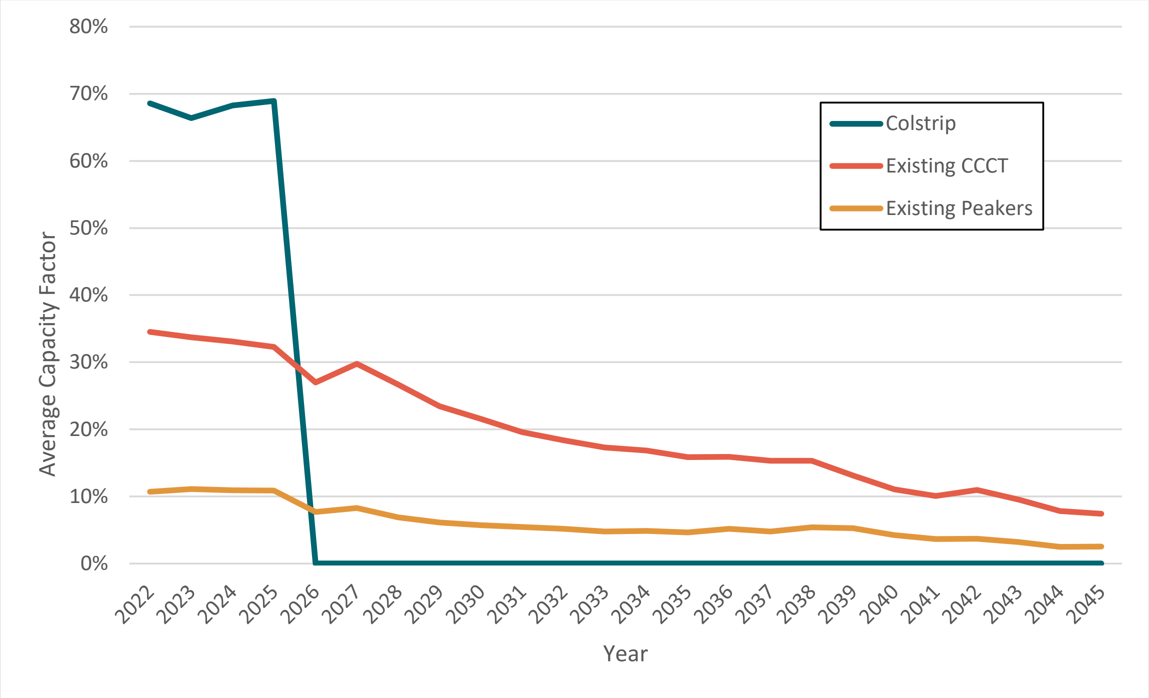


Figure 3-3 shows the annual percentage of time that the thermal resources dispatch, known as the capacity factor. Historically Colstrip dispatched around 85 percent to 90 percent of the time, but with increased costs, its dispatch has dropped below 70 percent. The existing natural gas CCCT plants average around a 35 percent capacity factor, with the highest dispatching units projected to run 60 percent to 70 of the time at the beginning of the time horizon. As new renewable resources are added to the portfolio, the projected dispatch of the existing natural gas CCCT decreases to around 7 percent by the end of the planning horizon. Existing natural gas peaking plants have always had low dispatch, since they are mostly used to maintain reliability during times of peak demand. The dispatch of the new peaking plants has an annual average capacity factor of 10 percent at the beginning of the planning horizon that drops to around 2 percent by the end of the planning horizon.

Figure 3-3: Projected Annual Thermal Resources Dispatch for PSE Existing Resources



MEETING CETA 2045 REQUIREMENTS. By 2045, 100 percent of retail sales is met by non-emitting and renewable resources. Retail sales is the total amount of energy delivered to customers. The preferred portfolio reduces the amount of energy delivered to customers by adding over 6.5 million MWh of new demand-side resources that include conservation and customer programs, and by adding almost 14.9 million MWh of new renewable resources. After demand-side resources and customer programs, PSE needs an additional 13.5 million MWh of non-emitting and renewable resources by 2045 to reach 100 percent of retail sales. The new wind, solar, biomass and hybrid resources in the preferred portfolio add 14.9 million MWh of non-emitting and renewable resources, making the preferred portfolio compliant with the 2045 CETA goal. Figure 3-4 breaks down how the preferred portfolio meets the 100 percent non-emitting and renewable resource requirement.

Figure 3-4: Calculation of 2021 IRP Preferred Portfolio CETA Compliance for 2045

	MWh
2045 Estimated Sales before Conservation[1]	29,051,232
Demand-side Resources	(6,565,285)
Line Losses	(1,529,044)
Load Reducing Customer Programs & PURPA	(1,493,096)
Sales Net of Conservation and Customer Programs	19,463,807
Existing Non-emitting and Renewable Resources[2]	(5,904,043)
Need for New Renewable/Non-emitting Resources	13,559,765
New Non-emitting and Renewable Resources	
Wind	10,767,902
Solar – Utility-scale	1,461,402
Solar – distributed ground and rooftop	963,861
Biomass	778,334
Hybrid renewable and energy storage	917,022
Total New Resources	14,888,520

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022.
2. Generation from existing resources assumes normal hydro conditions and P50 wind and solar.

Electric Resource Need

Reliability is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

1. **Peak hour capacity for resource adequacy (reliability)**: PSE must have the capability to meet customer's electricity needs during periods of peak demand;
2. **Hourly energy**: PSE must have enough energy available in every hour to meet customer's electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the requirements of the Clean Energy Transformation Act.

Meeting Peak Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of existing coal resources, PSE is forecast to begin to experience a peak capacity shortfall starting in 2026. PSE uses a loss of load probability (LOLP) consistent with the Northwest Power and Conservation Council to determine the peak capacity need for its service territory. Using the LOLP methodology, before any new demand-side resources, it was determined that 907 MW of capacity would be needed by 2027 and 1,381 MW of capacity by 2031. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis.

The resource adequacy analysis is complex and ensures the system has enough flexibility to handle balancing needs and unexpected events, such as variations in temperature, hydro, wind and solar generation, equipment failure and plant forced outages, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Resource adequacy requires that the full range of potential demand conditions are met, even if the potential of experiencing those conditions is relatively low.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar) and energy limited resources (batteries, pumped hydro storage and demand response), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility because it depends upon interactions between the various resources that make up each utility's unique system and is dependent on load shapes and supply availability. As a result, it is hard to compare the ELCC of PSE's resources with those of other entities and even PSE's ELCC's will change over time as system conditions change. A full description of the peak capacity and ELCC values is in Chapter 7.

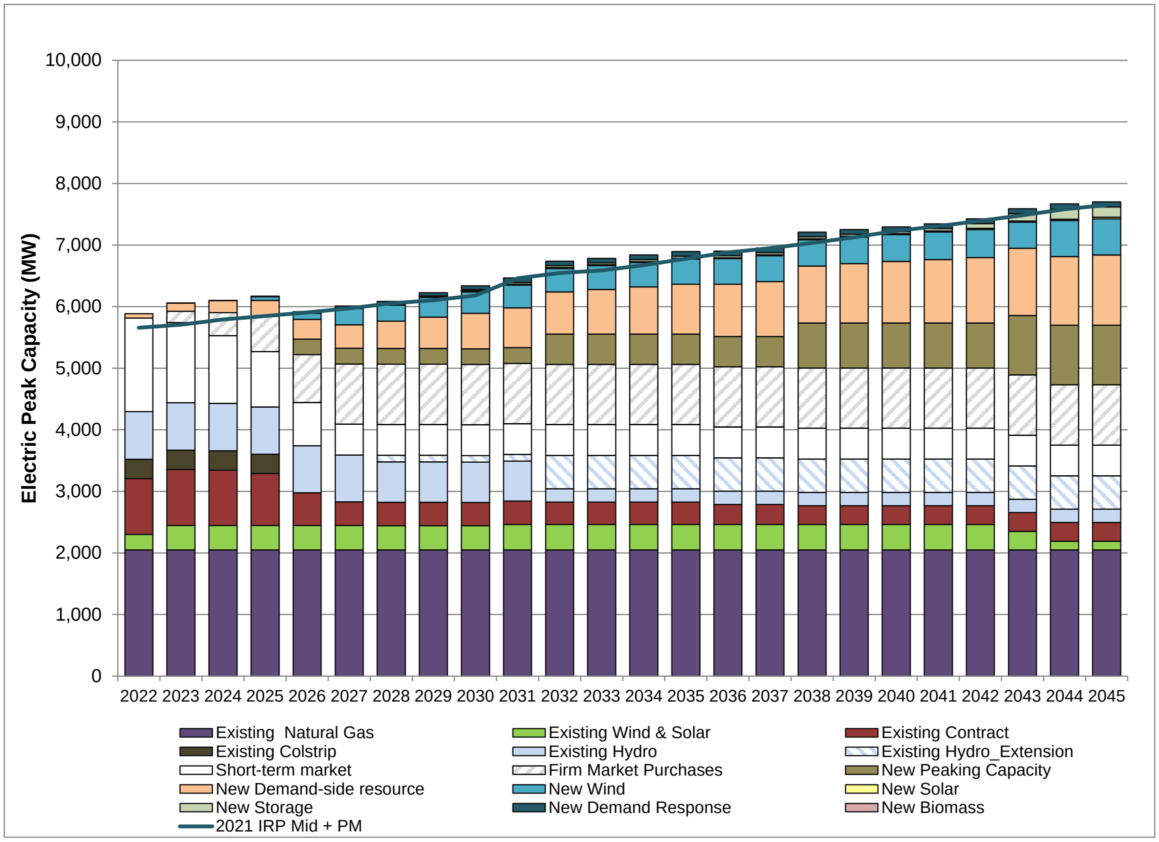
In addition to firm resources, PSE currently relies on market purchases from Mid-C to meet capacity needs. Evaluation of the existing wholesale electric market resulted in a recommendation that a portion of the available Mid-C transmission be used for firm resource adequacy (RA) qualifying capacity contracts or a reliable firm capacity resource in place of short-term energy purchases. Figure 3-5 shows, in annual increments, the conversion from short-term energy purchases to firm RA qualifying capacity purchases. As a result, in this IRP reliance on the availability of short-term market purchases at peak gradually declines over a 5-year period by 200 MW per year through the year 2027. The gray area shows PSE's total available transmission to the Mid-C market. After 2026, short-term market purchases stabilize at 500 MW and firm RA qualifying capacity purchases at 979 MW.

Figure 3-5: Short Term Market converted to Firm Resource Adequacy Qualifying Capacity Purchases

Year	Available Mid-C transmission	Short Term Market	Firm RA Qualifying Capacity Purchases
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

Figure 3-6 shows the preferred portfolio combination of new and existing resources required to meet the peak capacity need for the IRP mid demand forecast with an appropriate planning margin, and it reflects the peak capacity contribution of these resources. The graph also shows the market risk adjusted firm capacity (in the gray shaded bars) that will replace existing short-term Mid-Columbia energy contracts.

Figure 3-6: Preferred Portfolio Meeting Electric Peak Capacity and Reducing Market Risk



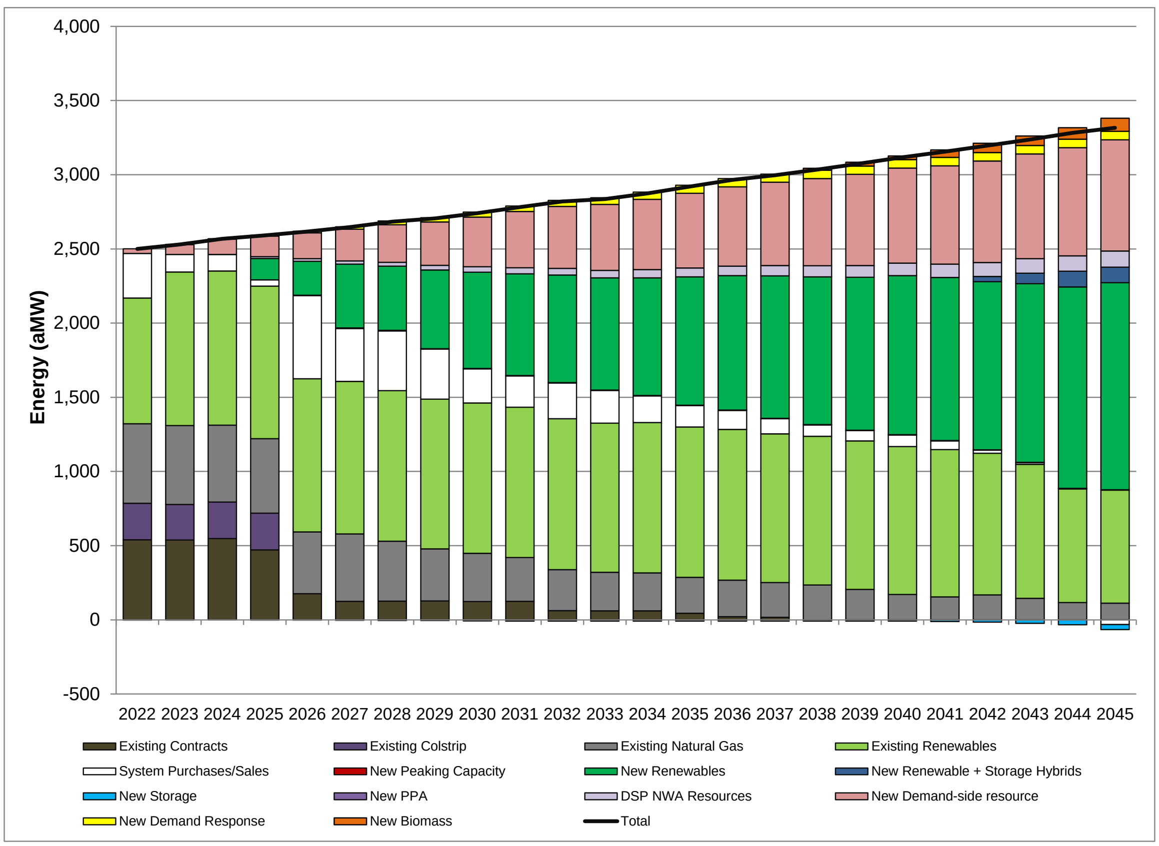
Renewable and distributed resources contribute to meeting peak capacity needs, however, peaking capacity is also needed to maintain reliability and meet required resource adequacy standards. The more than 750 MW of coal removed from PSE's portfolio by the end of 2025 is first replaced by demand-side resources, distributed energy resources and wind generation. Just 255 MW of new flexible, dispatchable capacity is added by 2026 to maintain reliability. The capacity need increases because an increase in balancing requirements is required to support the new intermittent renewable resources added to comply with CETA.

PSE evaluated early economic retirement of existing resources but that appears to increase cost. However, the economic dispatch of existing resources decreases significantly through the planning horizon as seen Figure 3-3 and is discussed further below.

Meeting Energy Need

Figure 3-7 shows the preferred portfolio combination of resources needed to meet the 2021 IRP mid demand forecast. Most of the energy need is met with renewable and distributed energy resources. The use of market purchases and sales declines over time. None of the energy requirements are satisfied with coal resources after 2025. The use of existing thermal resources significantly declines, with the capacity factor of PSE's combined-cycle combustion turbines decreasing from 70 percent for the highest dispatch units at the beginning of the planning horizon to 7 percent by the end. The pink bars represent demand-side resources, which significantly reduce total load. The black line on the chart is PSE's mid demand forecast and represents the demand at the generator, so it is grossed up for sales. This is different than the renewable need which is based on retail sales. Distributed energy storage resources are included in the portfolio but are barely visible in this chart because they are a net zero resource, meaning they do not produce any energy but rather store the energy produced by other generators. The storage resources appear as a negative value, below the line towards the end of the time horizon, and represent the energy stored.

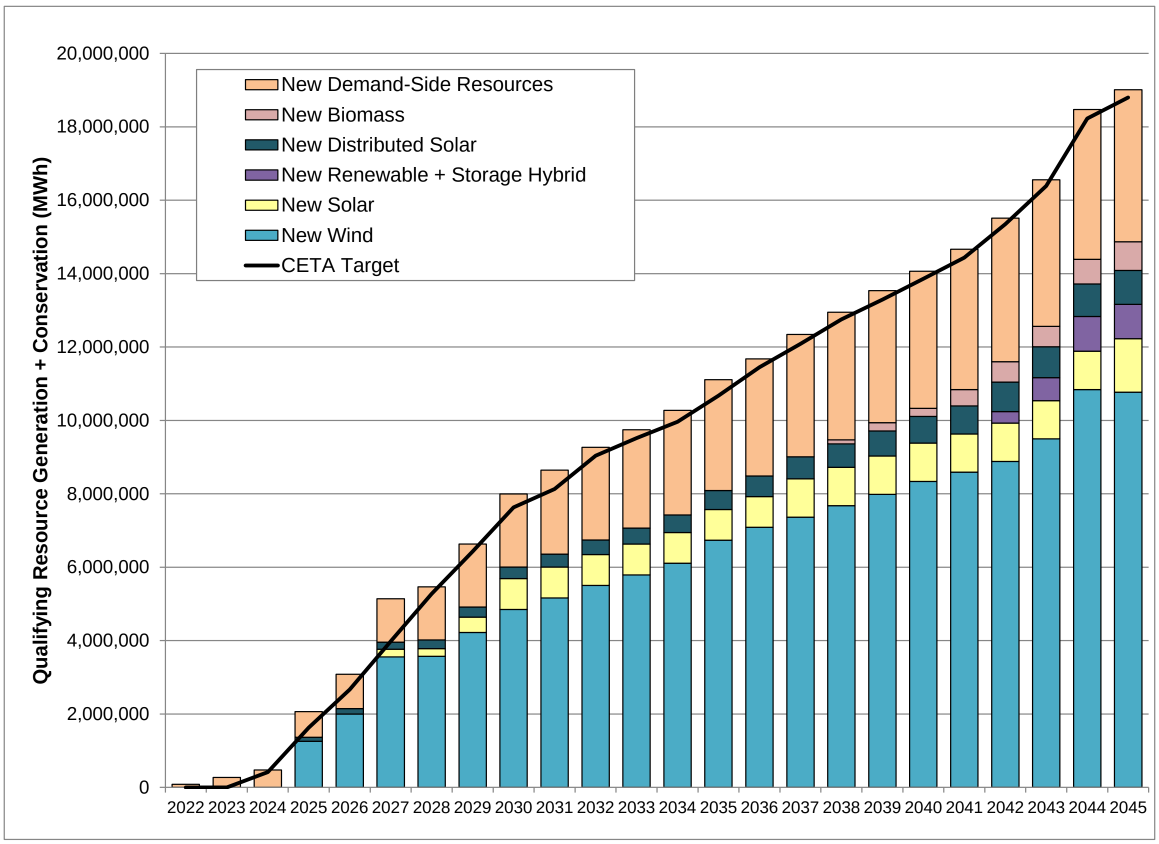
Figure 3-7: Preferred Portfolio Meeting Energy Requirements



Meeting Renewable Energy Need

The renewable energy need for both RCW 19.285 and CETA, based on the 2021 IRP mid demand forecast, is described in Chapter 8. The preferred portfolio assumes a linear ramp to achieve the 80 percent Clean Energy Transformation Standard in 2030 and 100 percent standard in 2045. Figure 3-8 shows how the new renewable resources meet the 7.6 million MWh renewable requirement in 2030 and 17.1 million MWh renewable requirement in 2045. Demand-side resources (DSR) significantly reduce loads and lower the renewable need; these include cost-effective energy efficiency, codes and standards, distribution efficiency and customer solar PV. The majority of the remaining renewable resource need is met by new wind, and then solar. Wind additions include in Montana, Wyoming and eastern Washington wind. Solar additions include utility-scale solar in eastern Washington, and distributed energy solar resources include delivery system non-wire alternatives and ground-mounted and rooftop solar PV. The chart below shows the total annual energy (MWh) produced by these resources.

Figure 3-8: Preferred Portfolio Meeting Renewable Energy Requirements



Key Findings by Resource Type

Distributed Energy Resources

There is no single perfect answer or resource that will solve all of the peak, energy and renewable needs. That is why a balanced portfolio is important, one that includes a mix of utility-scale and distributed energy resources, and a mix of intermittent, energy-limited and firm capacity resources. All of these are important components when determining the portfolio mix. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. DERs make lower peak capacity contributions and have higher costs, but they play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits.

ENERGY EFFICIENCY. PSE has never limited the funding needed to meet energy savings targets and has consistently met and exceeded the energy savings targets called for in the Energy Independence Act (RCW 19.285). In each two-year program period from 2014 through 2019, PSE set electric savings targets that were 13 percent, 9 percent and 10 percent higher than required by the Energy Independence Act, and PSE's actual savings were 20 percent, 14 percent and 14 percent higher, respectively, than PSE's targets.

PSE encourages customers to bundle as many energy efficiency measures together as possible. This is true in both the business and residential efficiency programs. In fact, the residential program offers a bonus financial incentive for including multiple measures in a single application. PSE's program for commercial new construction and deep retrofits offers higher incentive rates for deeper reductions in energy use. The preferred portfolio includes 793 MW of the 840 MW estimated technical potential for energy efficiency found in the Conservation Potential Assessment.

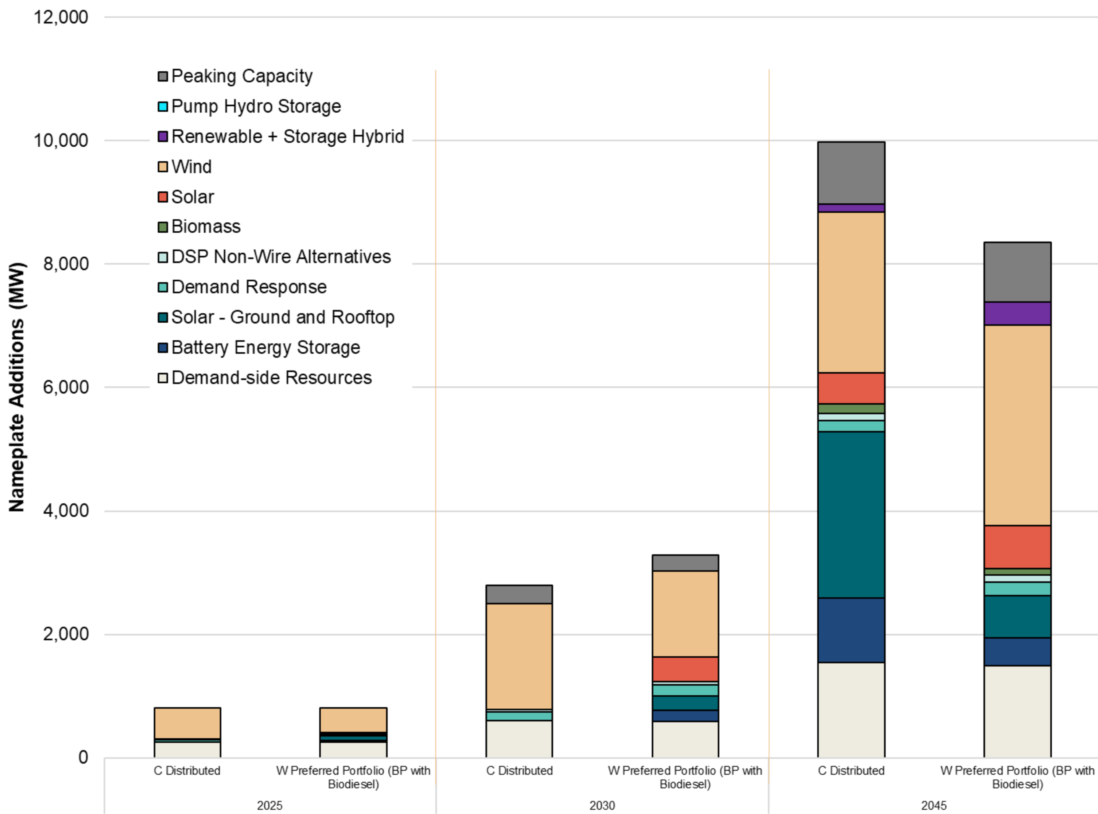
Energy efficiency is just one of the demand-side resources analyzed in this IRP. All of the demand-side resources are described in Chapter 2 and Appendix D.

BATTERY ENERGY STORAGE. The preferred portfolio includes four battery energy storage systems that range in duration from 2 to 6 hours and pumped storage hydro with a duration of 8 hours. Batteries are scalable, and fit well in a portfolio with small needs of short duration. Batteries also work as a solution for local distribution upgrades and capacity needs. In the optimized portfolio results, additional energy storage was not part of the optimized portfolio solution until the last 5 to 10 years of the planning horizon when the renewable requirement increased to more than 90 percent of delivered load. However, taking into account risk of transmission and additional customer benefits, battery energy storage is accelerated in the preferred portfolio. The lower peak capacity credit of energy storage means significantly more battery energy storage resources are needed to match the capacity provided by combustion turbines (the lowest cost resource). The preferred portfolio adds some distributed battery storage resources starting at 25 MW in 2025 and increasing to 175 MW by 2031.

SOLAR – GROUND AND ROOFTOP. Though utility-scale solar is a lower cost option for meeting CETA renewable requirements, given the transmission constraints involved in bringing remote resources to PSE's service territory, distributed solar resources have become an important part of the solution. PSE modeled both ground-mount and rooftop solar as an option to both meet CETA renewable requirements and local distribution system needs. The distributed solar includes options for both customer-owned solar (net-metering) and PSE-owned solar resources.

In Sensitivity C, which restricts transmission availability compared to the Mid Scenario portfolio, PSE analyzed the risk of obtaining new transmission contracts to eastern Washington and the availability of re-using existing transmission contracts. Based on these restrictions, more renewable resources are needed in western Washington to meet CETA renewable requirements, and the portfolio model waited until the end of the planning period to add a significant amount of distributed resources. The preferred portfolio takes the same amount of distributed resources and ramps them in over time starting in 2025 for a total of 680 MW of distributed solar. This is in addition to the 622 MW of net-metered, customer-owned solar for a total of 1,302 MW of distributed solar by 2045. Distributed solar is a good way to meet the CETA renewable requirements given transmission constraints, but it makes limited contributions toward meeting peak capacity need because it provides very little peak capacity value since PSE is a winter peaking utility. Figure 3-9 compares the preferred portfolio and Sensitivity C resource builds.

Figure 3-9: Resource Builds – 2021 IRP Preferred Portfolio and Sensitivity C (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



DEMAND RESPONSE. PSE modeled 16 demand response programs totaling 222 MW in nameplate capacity. Of those 16 programs, there are 4 different direct load control (DLC) hot water heater programs, along with critical peak pricing, DLC heating, EV charging, curtailment and critical peak pricing (CPP). The CPP programs are similar to a time-of-use (TOU) program.

To reflect the time needed to enroll customers in programs, five of the programs are ramped in starting in 2023, two programs are ramped in starting in 2025, and the remaining seven programs are ramped in starting in 2026. The five programs starting in 2023 were part of the least cost optimization in most of the portfolio sensitivities. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers. The total demand response program grows to 195 MW nameplate capacity by 2031. By 2045, an additional 21 MW of demand response is cost effective for a total of 217 MW of the 222 MW technically available.

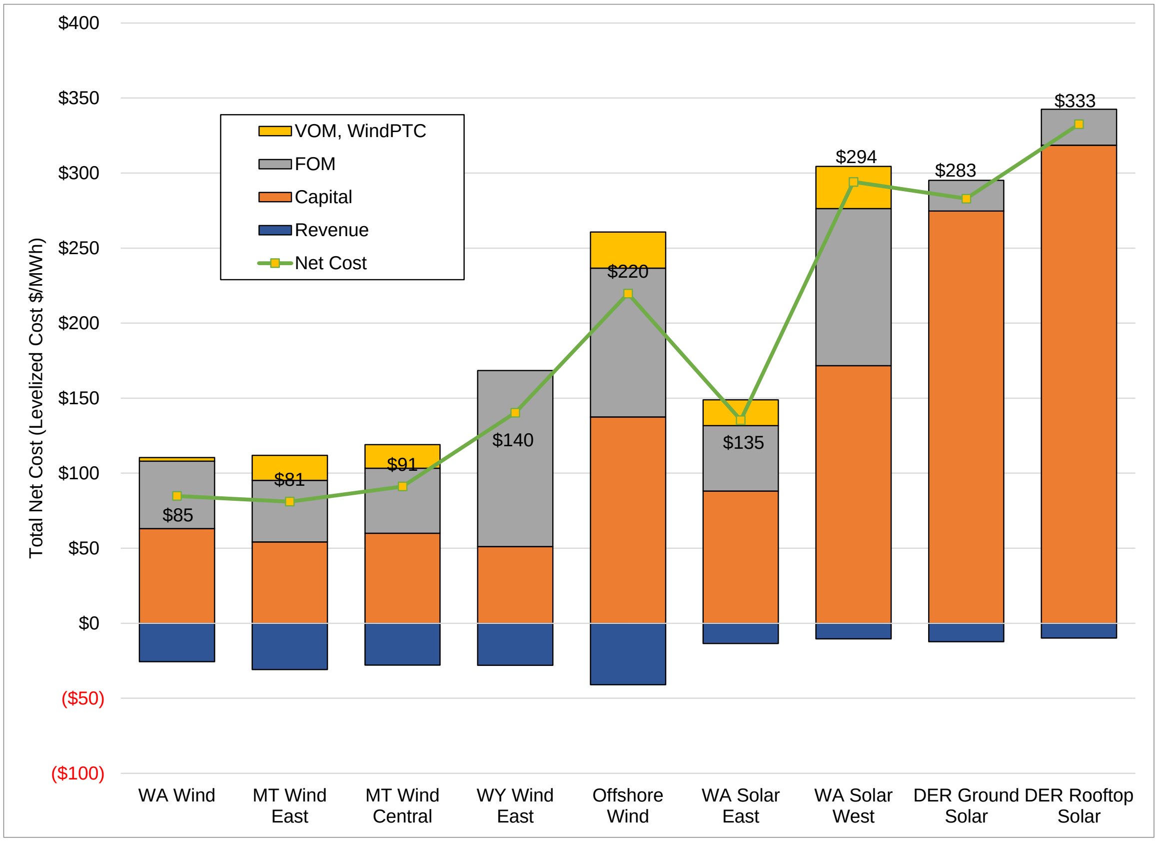
GRID MODERNIZATION. Proactive investments in grid modernization are critical to support the clean energy transition and maximize benefits. Investments in the delivery system are needed to deliver energy to PSE customers from the edge of PSE's territory and to support DERs within the delivery grid. Specific delivery system investments will become known when energy resources, whether centralized or distributed, begin to be sited through the established interconnection processes. The 10-year delivery infrastructure plans are described in Appendix M.

Utility-scale Renewable Resources

Significant investment in utility-scale renewable resources, in addition to DERs, will be needed to ensure that 100 percent of all retail electricity sales is served with renewable resources.

WIND AND SOLAR RESOURCES. The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources also contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio that relies on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up the portfolio cost. Increased renewable diversity can improve contribution to capacity needs, however resources outside of the Pacific Northwest region are limited given transmission constraints. After Montana and Wyoming wind, the costs of eastern Washington wind and solar are very close. Figure 3-10 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resources to meet CETA renewable requirements, followed by eastern Washington wind and solar. The levelized costs are calculated based on total resource costs; these include capital costs, variable operations and maintenance, and fixed operations and maintenance. Some resources include benefits from the production tax credit (PTC), and the investment tax credit (ITC). A full description of the ranges for the PTC and ITC is included in Appendix G. All resources include a benefit called revenue. This is the value of the resource in the market and is calculated as generation times the electric power price for every hour. The revenue and costs of the resources are calculated for every hour and then aggregated up to annual costs and benefit. These costs are then levelized by using net present value in 2022 dollars. Actual resource costs obtained through an RFP process could yield a different conclusion.

Figure 3-10: Levelized Cost of Wind and Solar Resources



TRANSMISSION CONSTRAINTS. Transmission capacity constraints have become an important consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the clean energy transformation targets. Thermal resources can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand. In contrast, renewable resources are site-specific and have variable generation patterns that depend on local wind or solar conditions, therefore they cannot always follow load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak capacity needs as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory. Transmission within PSE service territory will also be needed, but was assumed to be unconstrained due to delivery system planning processes and the specific projects identified in Appendix M.

The available transmission to eastern Washington can range from 700 MW to over 3,200 MW depending on the availability of new transmission contracts, upgrades on the system and the repurposing of existing contracts. PSE modeled a potentially available 750 MW of transmission from Montana and 400 MW of transmission from Wyoming. The full 750 MW of Montana wind and 400 MW of Wyoming wind appear to be cost-effective in this portfolio. There is significant risk with Wyoming wind because new transmission will need to be constructed to Wyoming, and PSE will also need to acquire new firm transmission contracts. After Montana and Wyoming wind are added to the portfolio, there is still an additional 600 MW of eastern Washington wind and 400 MW of eastern Washington solar needed by 2030. Given the risk in available transmission, over 200 MW of distributed solar is added to the portfolio to meet the 80 percent CETA renewable target in 2030. The actual location and type of renewable resources will depend on available transmission.

BIOMASS. Between 2035 and 2045, over 100 MW of biomass is added to the preferred portfolio. Although biomass has a higher capital cost than wind and solar, it is a baseload resource with an 85 percent capacity factor, which means that fewer biomass resources are needed to produce the same amount of energy that a resource such as solar can produce. PSE modeled wood waste biomass connected to lumber mills. Given the total number of mills located in western Washington, PSE estimates that around 150 MW of biomass may be feasible.

HYBRID RESOURCES. After 2040, 375 MW of hybrid wind and battery resources are added to the portfolio. Connecting a battery to an intermittent renewable resource helps to firm the capacity of the renewable resource so that it is more reliable during peak events and has a higher peak capacity contribution. However, with the battery being used to firm up the capacity of the wind resource, it is not available to meet flexibility needs, and it does not provide benefits to the transmission and distribution system. As a result, using the battery as an independent, distributed resource has more benefits to PSE than connecting it directly to a renewable resource. Hybrid resources are not cost competitive until the end of the time horizon.

Peaking Capacity with Biodiesel

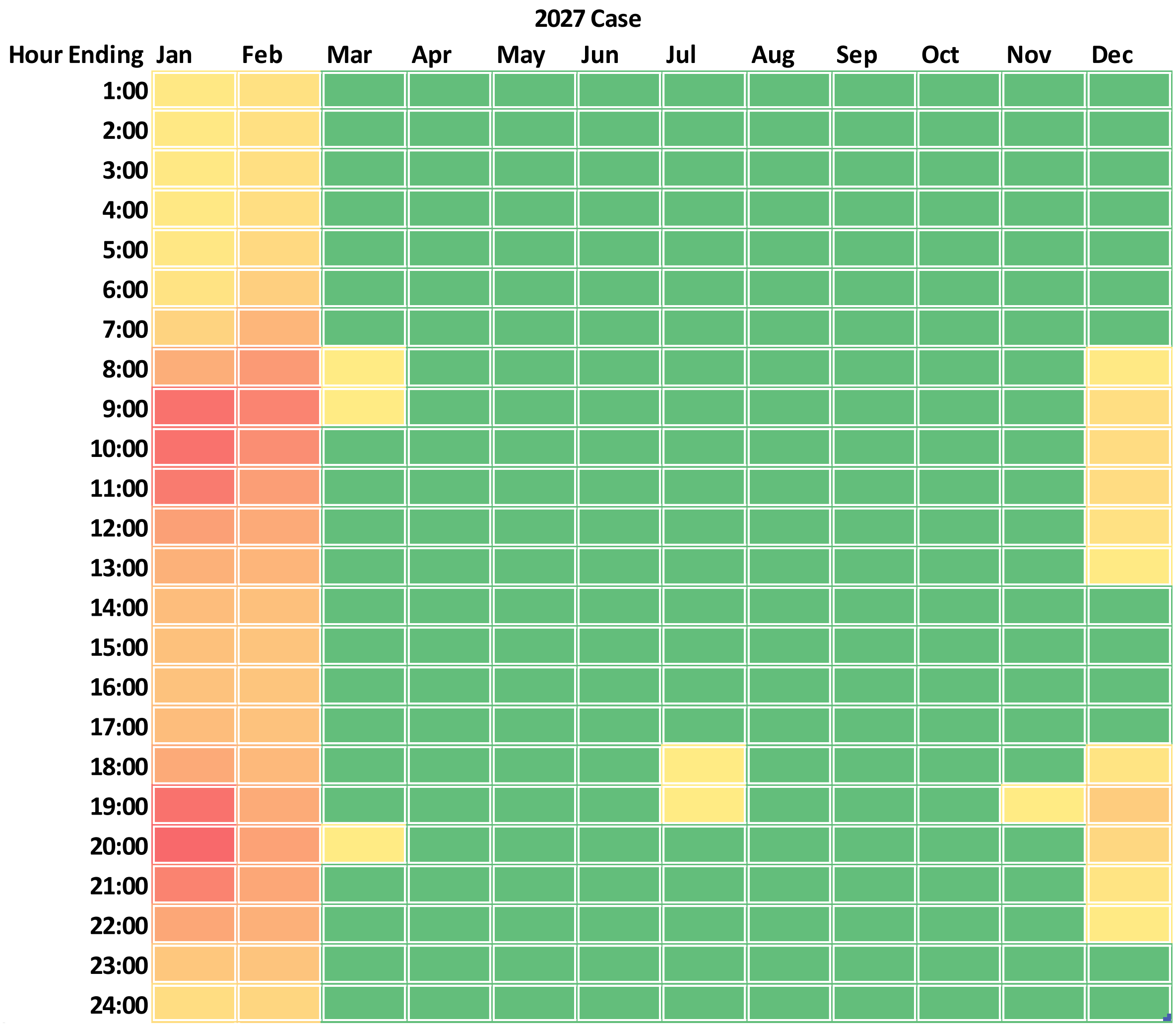
Beyond 2025, all sensitivities show a need for flexible, peaking capacity when 750 MW of coal generation is removed from PSE's portfolio in 2026. PSE is committed to pursuing all clean capacity resources first. The current modeling results show alternative fuel enabled combustion turbines as the most cost-effective resource to meet the capacity resource needs that cannot be otherwise met by demand-side resources and distributed and renewable resources. The model selected dispatchable combustion turbines as the least cost resource in particular to meet peak reliability needs, especially during periods of high load due to extremely cold weather conditions when renewable generation may be limited.

FUEL SUPPLY. In the resource adequacy analysis, PSE evaluated the biodiesel fuel supply needed for the peakers to maintain reliability. In 95 percent of simulations, the peakers are needed to run for 10,000 MWh or less to maintain resource adequacy, which is around 15 hours of run time annually. The maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[2] on biofuel production, the total annual production of biodiesel in Washington state is 114 million gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel, or about 0.7 percent of Washington State's 2020 annual production.

PEAK CAPACITY. The 12x24 table in Figure 3-11 shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number of hours of lost load summed by month and hour of day. The majority of the lost load hours occur in the winter months. In this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events by adding new resources. Current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability. The portfolio model needs to meet the loss of load events with resources that can be dispatched for 24 hours or more. Further discussion of the resource adequacy analysis can be found in Chapter 7.

2 / *https://www.eia.gov/biofuels/biodiesel/production/*

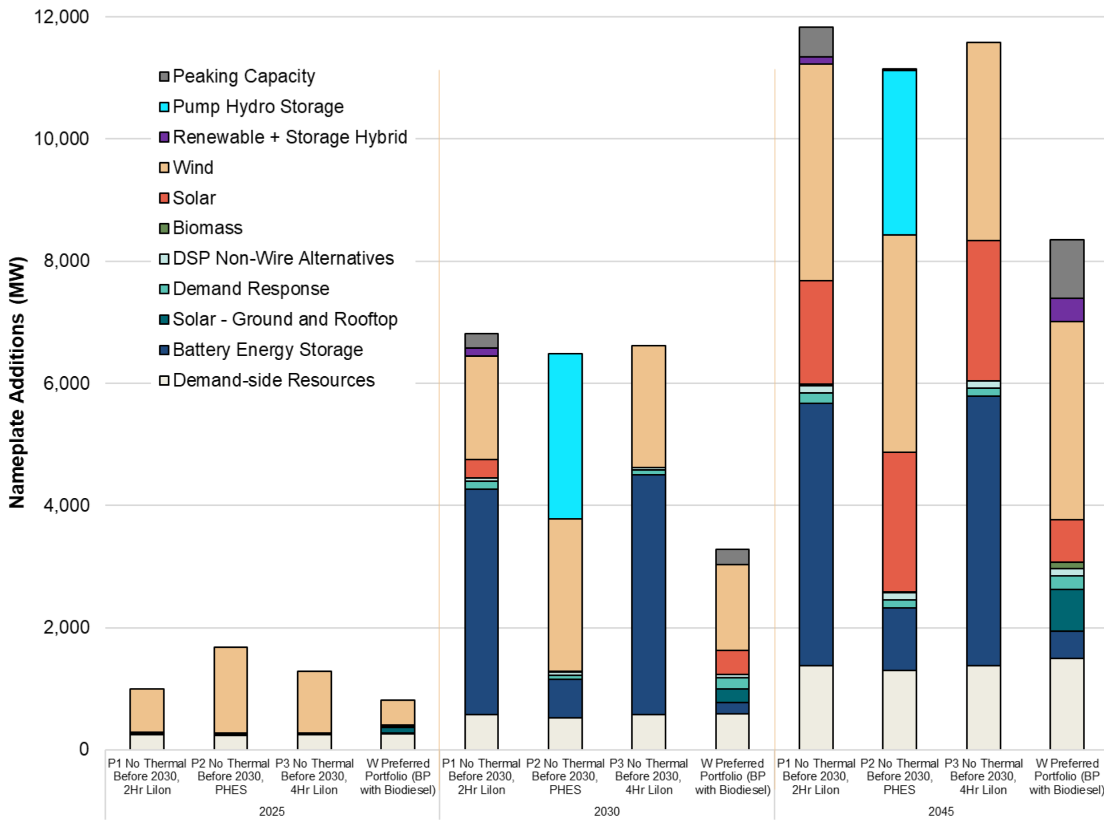
Figure 3-11: Loss of Load Hours for 2027



PSE's winter peak has notably different characteristics than a summer peak in other parts of the Western Interconnect. Summer peaking events occur in the late afternoon/evening when the day is the hottest and only last a few hours in the evening. Energy storage is a good solution for summer peaking events. In contrast, winter events can last several days at a time and temperatures can drop low during the night and stay low throughout the day. Since energy storage is a short duration resource that has a low peak capacity credit, it is not a good fit for winter peaks. With lower peak capacity credit, more energy storage resources are needed to replace the new peaking capacity added in the portfolio.

To better understand how energy storage can meet PSE's peak needs, PSE evaluated several portfolios in Sensitivity P. Sensitivity P removed new peakers as an option and forced the model to find alternative solutions. In the P1 portfolio, the first resource selected to fill peak need was 2-hour lithium-ion batteries. In the P2 portfolio, 2-hour lithium-ion and flow batteries were removed as an option and the model optimized to a solution involving a combination of pumped hydro storage and 4-hour lithium-ion batteries. The P3 portfolio removed the pumped hydro storage option and just added 4-hour lithium-ion batteries to meet peak needs. Figure 3-12 shows the total builds for the preferred portfolio and portfolios P1, P2 and P3. It takes a significant amount of energy storage and associated cost to replace the biodiesel peaker.

Figure 3-12: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity P, Transmission Build Constraint, Cumulative Additions by Nameplate (MW)



Without access to the biodiesel peaker, Sensitivity P produced much higher portfolio costs. Figure 3-13 compares the total portfolio costs for 2045 for the preferred portfolio and portfolios P1, P2 and P3. The lowest cost portfolio is portfolio P2 at $22.85 billion, $6.7 billion more than the preferred portfolio.

Figure 3-13: Portfolio Cost for the Preferred Portfolio and P1, P2 and P3 Portfolios

Portfolio	Portfolio Cost (Billion $, 24-year levelized)
Preferred Portfolio	$16.11
P1: 2-hr Li-Ion	$30.84
P2: Pumped storage hydro	$22.85
P3: 4-hr Li-Ion	$39.01

While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional peaking capacity plants of any kind in the future, alternative fuel peakers appear to be the least cost resource for meeting peak reliability needs at the time of this analysis. In all sensitivities that allowed the addition of new combustion turbines, at least one combustion turbine is added by 2026 and a second combustion turbine is added by 2030. Combustion turbines have the highest peak capacity value because of their ability to dispatch as needed with no duration limits. PSE is further exploring renewable and alternative fuel supply availability and technology.

Preferred Portfolio Decisions

A full discussion of all portfolios modeled in the 2021 IRP can be found in Chapter 8. This section focuses on the preferred portfolio and captures the decisions that informed the 10-year clean energy action plan and the 24-year resource plan.

Customer Benefits Analysis and Costs

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. As a result, the analysis of the equitable distribution of burdens and benefits is new to the resource planning process in the 2021 IRP. PSE is excited to incorporate these new ideas into the process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. A full discussion of how the customer benefit indicators were established is included in Chapter 8. Figure 3-14 shows the results of the

Customer Benefits Analysis and the overall portfolio rankings at the 24-year time horizon. These outputs have been color coded from red (least benefit) to green (most benefit). The Mid portfolio is the lowest cost portfolio that meets CETA requirements at $15.53 billion, but in terms of customer benefit indicators, it ranks at number 14 out of 22. To be included in the Customer Benefit Analysis portfolios must maintain consistency across demand and electric price forecasts, meet CETA requirements and represent current carbon regulation; therefore, not all portfolios were included.

Figure 3-14: Customer Benefits Analysis –Overall Portfolio Rank and Costs for 2045

Portfolio Sensitivity	Overall Rank	24-year Levelized Portfolio Cost (Billion $)
1 Mid	14	$15.53
A Renewable Overgeneration	13	$17.11
C Distributed Transmission	20	$16.35
D Transmission/build constraints - time delayed (option 2)	11	$15.54
F 6-Yr DSR Ramp	17	$15.54
G NEI DSR	10	$15.24
H Social Discount DSR	8	$15.77
I SCGHG Dispatch Cost - LTCE Model	3	$15.41
K AR5 Upstream Emissions	12	$15.56
M Alternative Fuel for Peakers – Biodiesel	1	$15.44
N1 100% Renewable by 2030 Batteries	6	$32.03
N2 100% Renewable by 2030 PSH	15	$66.64
O1 100% Renewable by 2045 Batteries	9	$23.35
O2 100% Renewable by 2045 PSH	5	$46.95
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$30.84
P2 No Thermal Before 2030, PHES	18	$22.85
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$39.01
V1 Balanced portfolio	4	$16.06
V2 Balanced portfolio + MT Wind and PSH	16	$16.61
V3 Balanced portfolio + 6 Year DSR	7	$16.26
W Preferred Portfolio (BP with Biodiesel)	2	$16.11
AA MT Wind + PHSE	19	$15.84

As shown in Figure 3-14, the Customer Benefit Analysis suggests Sensitivity M is the portfolio that provides the greatest benefit to PSE customers. PSE recognizes that this portfolio has many desirable attributes, including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which reduce transmission risk and may provide benefits on the distribution system.

Comparing the costs of Sensitivity M with Sensitivity W yields only a relatively small increase in costs and provides a greater investment in distributed energy resources, thus balancing transmission risks. Therefore, PSE has selected Sensitivity W, the Balanced Portfolio with biodiesel fuel, as the preferred portfolio.

Figure 3-15 compares the portfolio M and W builds by 2030. Portfolio W is a balanced portfolio that takes earlier action on DERs and includes more distributed solar and battery energy storage in the first 10 years of the plan than portfolio M.

Figure 3-15: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity M, Transmission Build Constraint Cumulative Additions by Nameplate (MW)

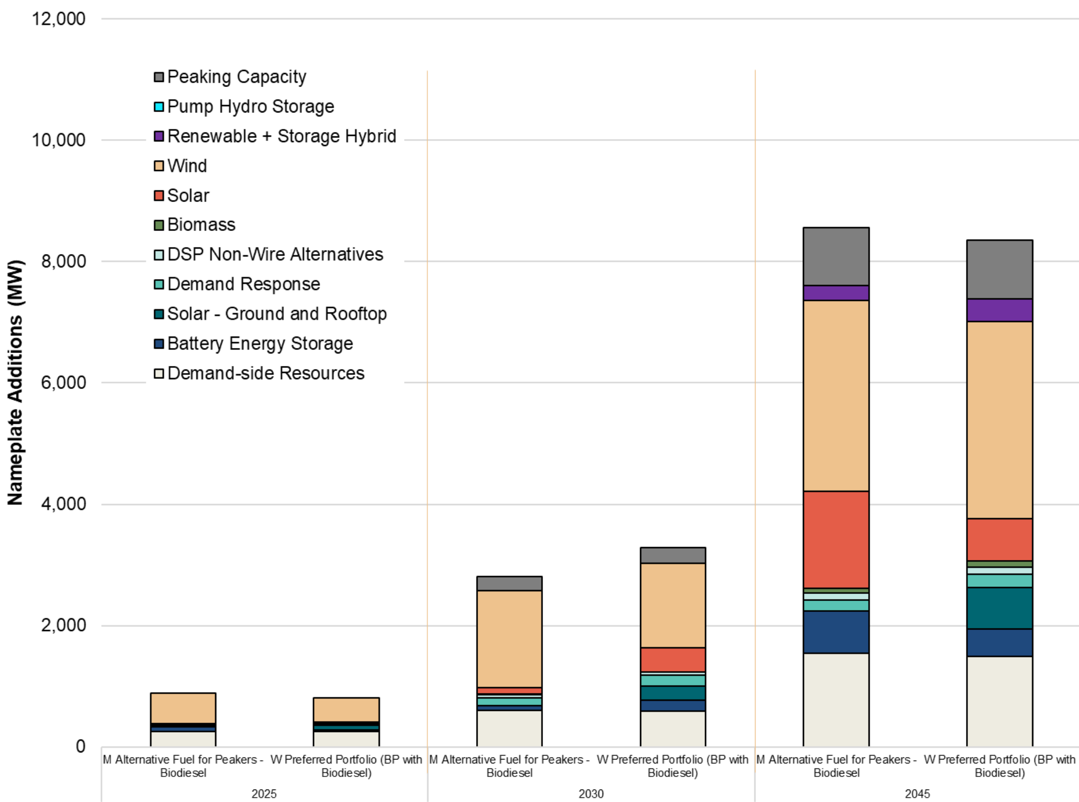


Figure 3-16 shows the results of the Customer Benefits Analysis for the 10-year time horizon. With the addition of the distributed energy resources in the early part of the planning horizon, Sensitivity W ranked number 1 in the 10-year rankings.

Figure 3-16: Customer Benefits Analysis –Overall Portfolio Rank for 2031

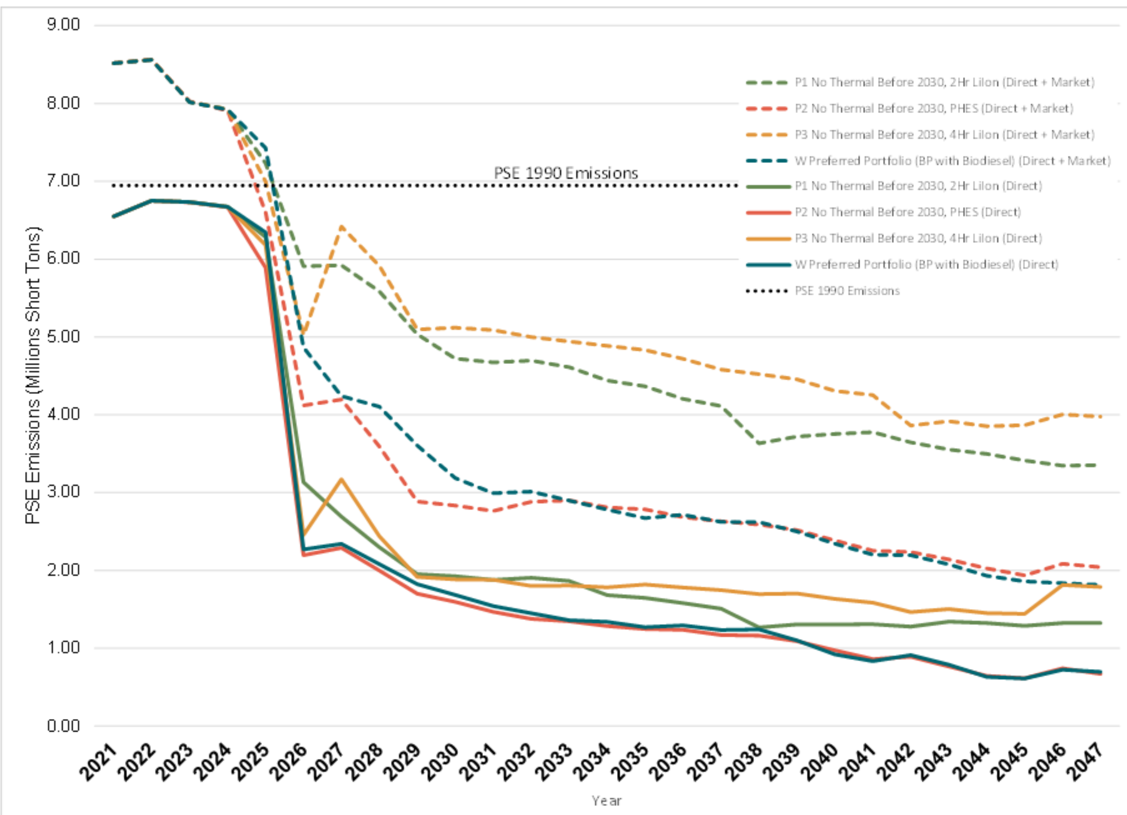
Portfolio Sensitivity	Overall Rank	10-year Levelized Portfolio Cost (Billion $)
1 Mid	12	$6.65
A Renewable Overgeneration	9	$7.09
C Distributed Transmission	20	$6.65
D Transmission/build constraints - time delayed (option 2)	15	$6.68
F 6-Yr DSR Ramp	11	$6.50
G NEI DSR	16	$6.37
H Social Discount DSR	18	$6.47
I SCGHG Dispatch Cost - LTCE Model	17	$6.61
K AR5 Upstream Emissions	19	$6.71
M Alternative Fuel for Peakers – Biodiesel	8	$6.67
N1 100% Renewable by 2030 Batteries	5	$10.86
N2 100% Renewable by 2030 PSH	14	$19.92
O1 100% Renewable by 2045 Batteries	13	$7.51
O2 100% Renewable by 2045 PSH	4	$11.77
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$13.36
P2 No Thermal Before 2030, PHES	7	$9.94
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$15.38
V1 Balanced portfolio	2	$6.90
V2 Balanced portfolio + MT Wind and PSH	6	$7.13
V3 Balanced portfolio + 6 Year DSR	3	$6.84
W Preferred Portfolio (BP with Biodiesel)	1	$6.91
AA MT Wind + PHSE	10	$6.78

Portfolio Emissions

All sensitivities that meet CETA renewable requirements show significant reduction in emissions throughout the planning horizon. Figure 3-17 compares CO_2 emissions for Sensitivity W, preferred portfolio with Sensitivity P portfolios, where the peaking capacity is replaced with different combination of renewable or non-emitting resources. The chart shows direct emissions from the generating resources plus upstream emissions in the solid lines, and direct emissions plus upstream emissions plus market purchases in the dashed lines. The graph does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to

2045. Rather direct emissions are shown for analysis. Direct emissions decrease over time as thermal resources are replaced with renewable generation. In Sensitivity P, more energy storage resources are added to the portfolio and market purchases are used to charge the storage resources since there is not enough surplus energy in PSE's portfolio. The market purchases cause a large increase in emissions; as can be seen by the difference between the solid and dashed lines for the Sensitivity P portfolios. Also, comparing the solid lines for Sensitivity W, preferred portfolio, and Sensitivity P shows that the direct emissions from PSE's resources are lower in Sensitivity W, preferred portfolio. This is because the heat rate of the new peaking resource, run on biodiesel fuel, is more efficient than the older thermal generators in PSE's fleet, the new peaking resource has lower emissions. When new energy storage resources are added in Sensitivity P portfolios, the increased generation from the existing fleet increases direct emissions.

Figure 3-17: CO_2 Emissions – Preferred Portfolio and Sensitivity P
(Solid lines show direct emissions plus upstream emissions, dotted lines show direct emissions plus upstream emissions plus market purchases. Does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)



COST OF CARBON REDUCTIONS. To calculate the cost of reducing carbon emissions, PSE divided the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 3-18 compares the results of this calculation for the preferred portfolio, Sensitivity N (100 percent renewable resources by 2030), Sensitivity O (where all thermal resources are retired by 2045), and Sensitivity P (new peaking capacity is replaced with alternative resources). The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The preferred portfolio is very efficient at reducing portfolio emissions because it uses new peaking capacity fueled with biodiesel to meet peak capacity needs.

Figure 3-18: Cost of Emissions Reductions Compared – Mid Scenario, Preferred Portfolio and Sensitivities N, O and P

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / Billion $)
1 Mid Scenario Portfolio	53.87	$15.53	-
Preferred Portfolio	52.77	$16.10	0.52
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
O1 100% Thermal resources retired by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Thermal resources retired by 2045 – PHES	43.54	$46.95	3.04
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions

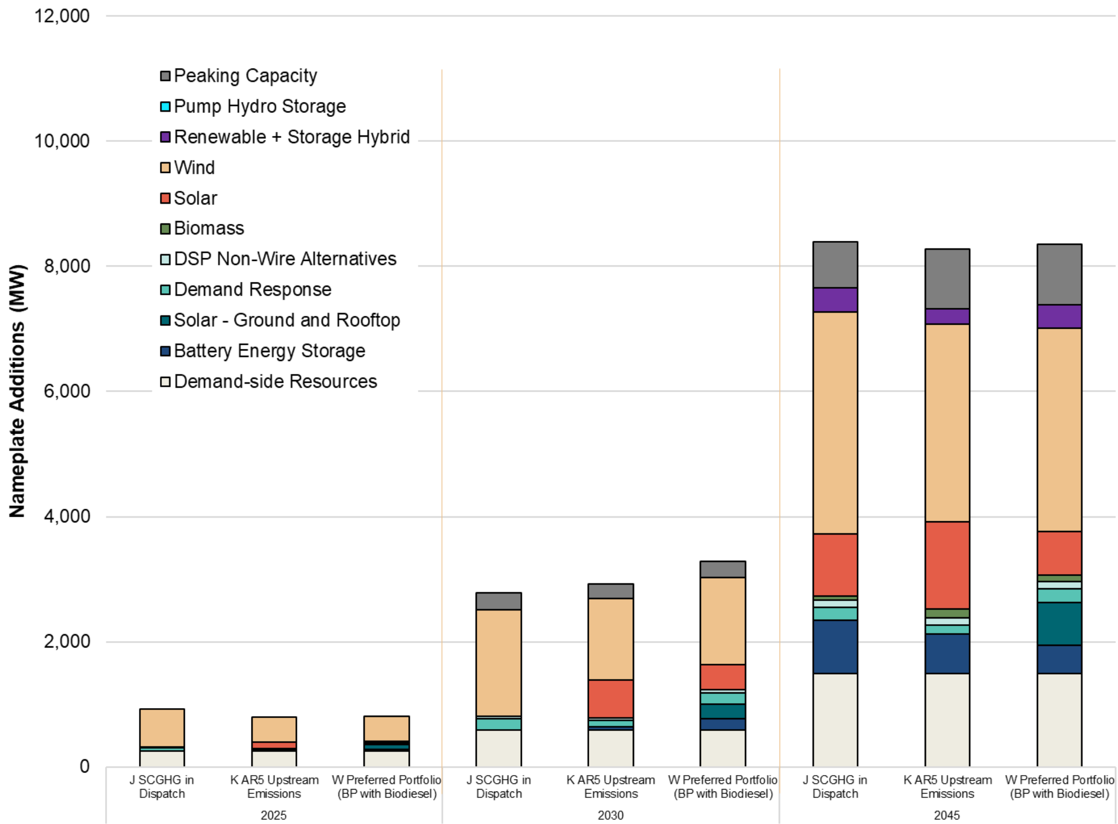
Social Cost of Greenhouse Gases (SCGHG)

CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resource options. As a result, PSE has modeled SCGHG as an adder in the portfolio model. The SCGHG is described in more detail in Chapter 5.

In response to stakeholder requests, PSE modeled different SCGHG approaches. Utilizing different SCGHG modeling approaches does not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements. Renewable resource requirements to comply with CETA are the key constraint that drives portfolio resource additions and costs. The different SCGHG modeling approaches are described in detail in Chapter 8.

In response to stakeholder requests, PSE also modeled an alternate upstream emission content. PSE applied upstream emission rate consistent with Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) in all portfolio modeling, and then evaluated a sensitivity using upstream emissions consistent with IPCC's Fifth Assessment Report (AR5). While AR5 increased upstream emissions for natural gas, it did not change resource builds or retirements compared to AR4. Figure 3-19 is a comparison of builds for the different modeling methodologies.

Figure 3-19: Resource Build for 2021 IRP Preferred Portfolio and Sensitivities J and K (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



Temperature Variations and Fuel Conversion Impacts

PSE evaluated temperature variations that increased the summer loss of load events. This temperature sensitivity is one model of possible weather changes and provides a preliminary view of a possible impact of warming temperatures as a result of climate change. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made to inform the preferred portfolio. Details are provided in Chapter 7 for the resource adequacy analysis, and portfolio results are presented in Chapter 8.

PSE will continue to model weather trends under different scenarios to better understand how summer extreme events can affect resource adequacy, but also to ensure that PSE continues to plan for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past three years, three separate regional events outside of PSE's control have occurred, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipates future changes to the resource adequacy analysis will include both winter and summer resource adequacy analyses, and PSE will also work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

In the 2021 Washington State legislative session, some proposals have been introduced that propose to convert from natural gas to electricity for power supply. This would significantly increase electric loads and associated peak loads. Since this would convert natural gas heating to electric heating, the majority of the increased loads would happen in the winter. PSE ran a sensitivity in this IRP to examine large-scale conversion of natural gas heating to hybrid electric heat pumps. This sensitivity increased electric loads by over 35 percent by 2045 and winter peak loads by over 17 percent by 2045. Natural gas sales decreased by 74 percent by 2045. This sensitivity assumed conversion to hybrid air-source heat pumps with natural gas backup that switch from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. More details on the Gas to Electric sensitivity results are presented in Chapters 8 and 9.

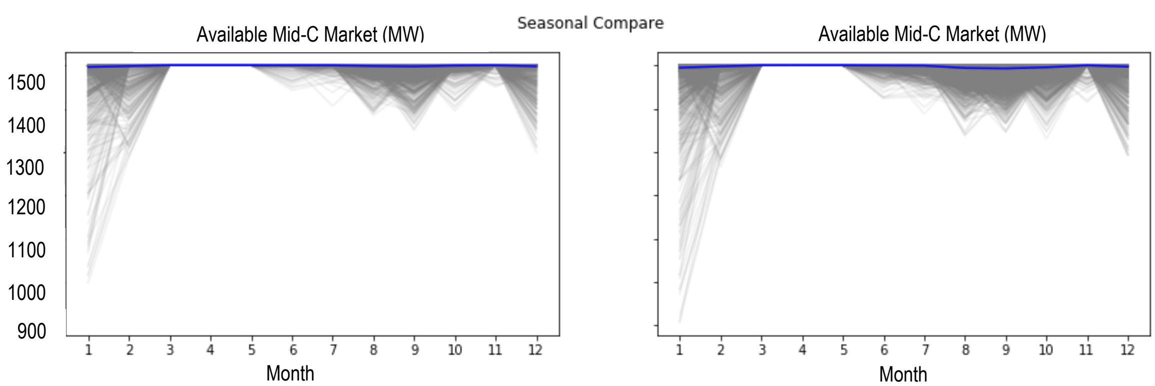
For future IRP work, PSE will look at integrating several of these scenarios to include temperature variations, gas-to-electric conversion and increased electric vehicle loads. Separately, each of these factors can change PSE's load shapes in different ways, but it is important to plan for how combined changes may affect PSE's load shapes.

Firm Resource Adequacy Qualifying Capacity Contracts

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy model.

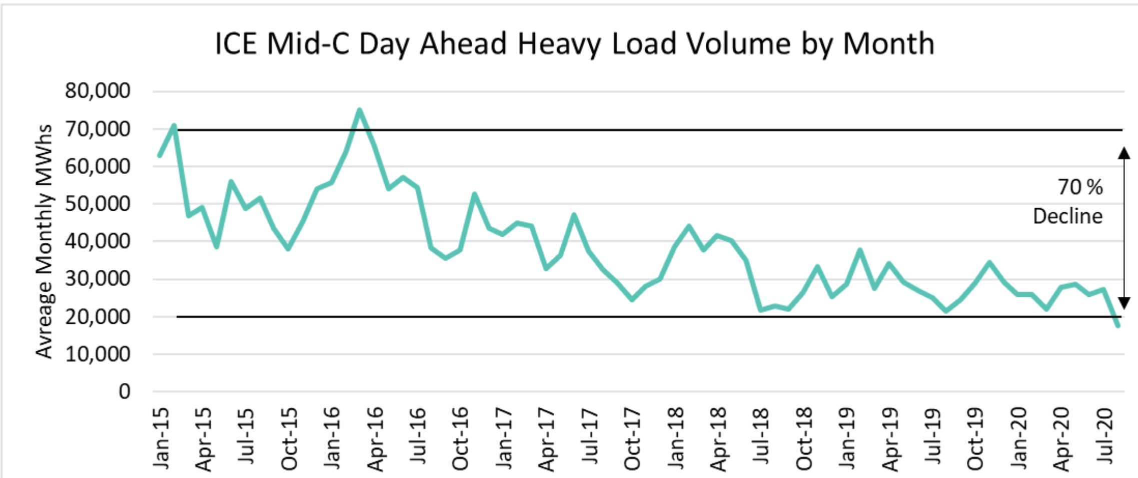
Figure 3-20 shows the results of the resource adequacy modeling. Over the last few years, several studies from regional organizations show that the Pacific Northwest may experience a capacity shortfall in the near term. PSE's resource adequacy model takes curtailment events from the Northwest Power and Conservation Council's resource adequacy model and allocates a portion of the curtailments to PSE's portfolio. The chart illustrates the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 3-20: Reduction to Available Mid-C Market



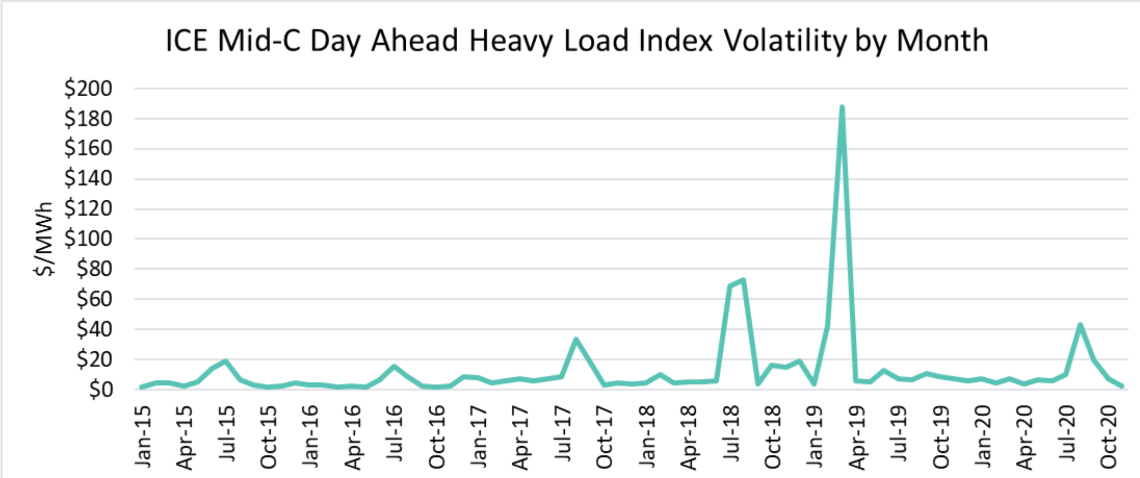
In the market risk assessment, PSE took this assessment further and analyzed the availability of the market during more recent events. Reductions in traded volume in the day-ahead market indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available for market participants to trade. This also is suggestive of more energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 3-21 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 3-21: Mid-C Day-ahead Heavy Load Volume Timeline



The market risk analysis also shows that price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip; in March 2019, when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020, during a west-wide heat event. The volatility of day-ahead heavy load prices is shown in Figure 3-22.

Figure 3-22: Volatility of Heavy Load Mid-C Day-ahead Prices



Coinciding with the retirement of legacy baseload capacity and the decline of market availability, several regional investor-owned utilities (IOUs) have reduced their assumptions of available market purchases in their IRPs. Compared with other IOUs in the region, PSE's market purchases are much higher than other IOUs, putting PSE at risk if short-term market purchases are not available.

Taking into account the results from the resource adequacy analysis, the downward trend in trading volumes over the last five years and the low availability of market during regional events, PSE proposes to reduce its reliance on short-term market purchases to 500 MW by 2027 and convert a portion of its 1,500 MW of Mid-C transmission to firm resource adequacy qualifying capacity contracts instead of relying on the short-term market. This means that the firm transmission is still available and will be evaluated during the RFP process for the lowest reasonable cost way to firm up the resources behind the transmission.

Reducing market purchases to 500 MW increases the peak capacity deficit in 2027 from 906 MW to 1,853 MW. In Sensitivity WX, PSE evaluated a portfolio in which available transmission to Mid-C was reduced and replaced with new peakers to address the capacity deficit. The result was a portfolio that added approximately 1,000 MW of peaking resources. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict. PSE's transmission can be used to procure new firm contracts or resources that can be delivered to Mid-C market hub and then used to deliver energy to PSE. The total cost of the preferred portfolio already includes estimates of the wholesale market price for the firm contracts proposed, but does not include any capacity premium that may be added. It is this premium that is difficult to predict, and PSE will learn more about those costs and what is available in the next RFP.

The regional resource adequacy program is currently under development and will impact PSE's capacity need should PSE decide to participate. Sufficient program design details are not yet available to evaluate the program's impact on PSE's resource adequacy analysis, however, we know that the program will define the types of contracts that will qualify to meet resource adequacy. PSE will be able to assess program impacts in time for the IRP update in two years.

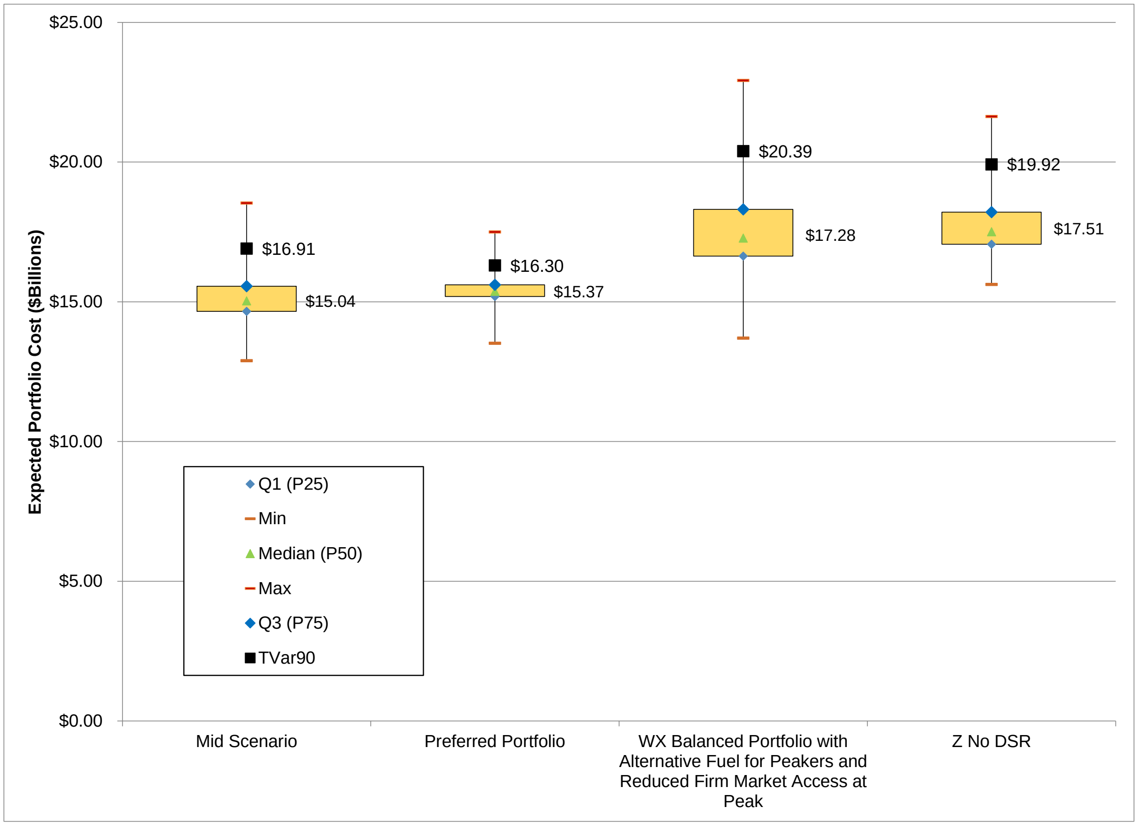
Summary of Portfolio Risk

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. For this purpose, PSE takes the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, natural gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can observe how risky the portfolio may be and where significant differences occur when risk is analyzed.

PSE's approach to the electric stochastic analysis hold portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information. Nevertheless, the result of the risk simulation provide an indication of portfolio costs risk range under varying input assumptions. In Figure 3-23, the expected portfolio costs for each portfolio are being compared across four portfolios; Mid, Preferred Portfolio, Sensitivity WX (Balanced portfolio with Market reduction), and Sensitivity Z (No DSR). The left axis represents the costs and the right axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio and is a measure of the center of the date. The interquartile range box represents the middle 50% of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

3 / Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Figure 3-23: Range of Portfolio Costs across 310 Simulations



The interquartile range for the Preferred Portfolio with Biodiesel is comparatively narrow and has the lowest TailVar90 at $16.3 billion dollars suggesting that the overall expected portfolio costs is the least variable compared to the other portfolios. The smaller range on the preferred portfolio indicates that this portfolio has the lowest volatility and the lowest risk than the other portfolios tested. Including conservation in the portfolio reduces both costs and risks, as can be seen in the comparison of costs and ranges with Sensitivity Z, No DSR. Sensitivity WX replaces the 1,000 MW of short-term market with frame peakers. In this portfolio, the costs are higher because of the cost of new resources, which is why the median cost is higher than the preferred portfolio. This portfolio also has a large range in costs, indicating higher volatility and risk. The conclusion of this simulation is that replacing the short-term market with natural gas plants does not reduce risk, it is simply exchanging market price risk for natural gas fuel risks. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

3. NATURAL GAS SALES RESOURCE PLAN

Resource Additions Summary

The additions to the natural gas sales portfolio are summarized in Figure 3-24, followed by a discussion of the reasoning that led to the plan. Peak use during the winter heating seasons must be met in the natural gas analysis. PSE’s winter heating season is from November to February; as a result, the years shown here reference the natural gas year, so 2025/26 means the natural gas year from November 2025 through October 2026.

Figure 3-24: Natural Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

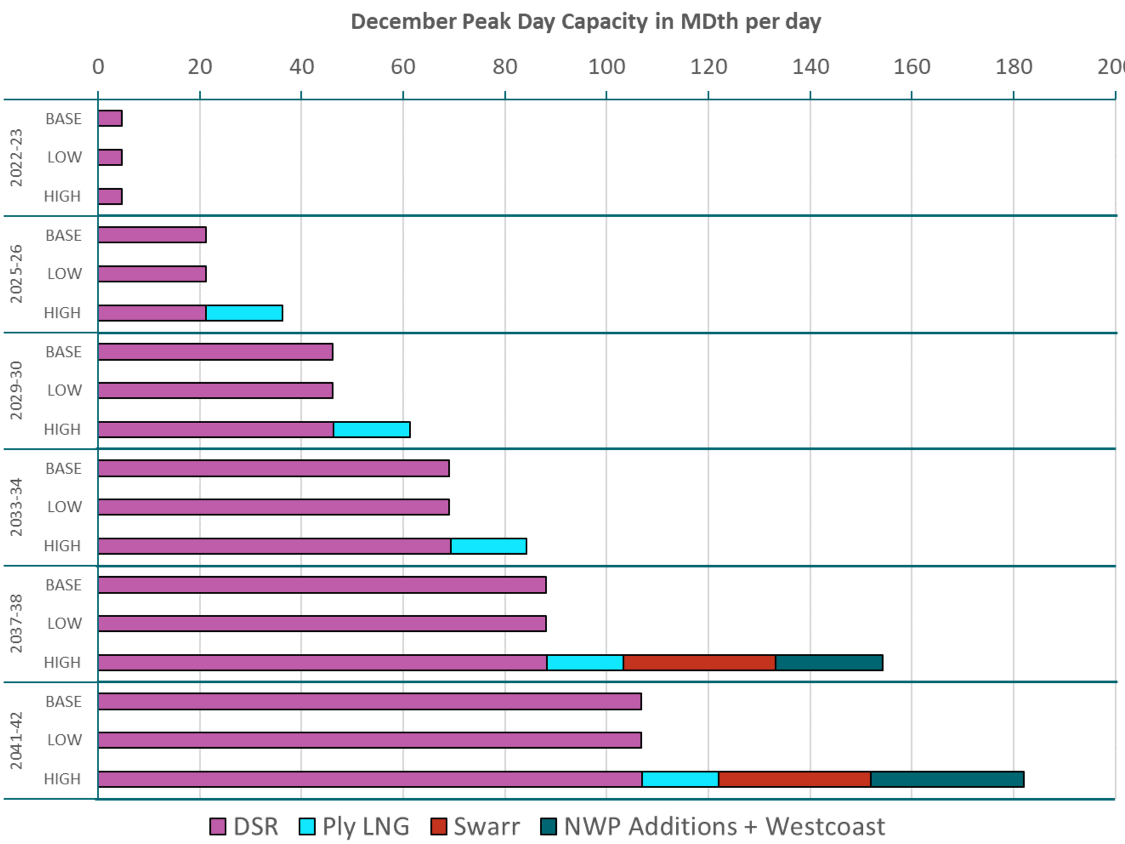
	2025/26	2030/31	2041/42
Conservation	21	53	107

The natural 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. In the draft 2021 IRP, conservation was the most cost effective resource, and it alone was enough to meet the need over the entire study period.

Natural Gas Sales Results across Scenarios

As with the electric analysis, the natural gas sales analysis examined the lowest reasonable cost mix of resources across a range of scenarios. Three scenarios were tested in the 2021 IRP: Mid, Low and High. Figure 3-25 illustrates the lowest reasonable cost portfolio of resources across these three potential future conditions.

Figure 3-25: Natural Gas Sales Portfolios by Scenario (MDth/day)

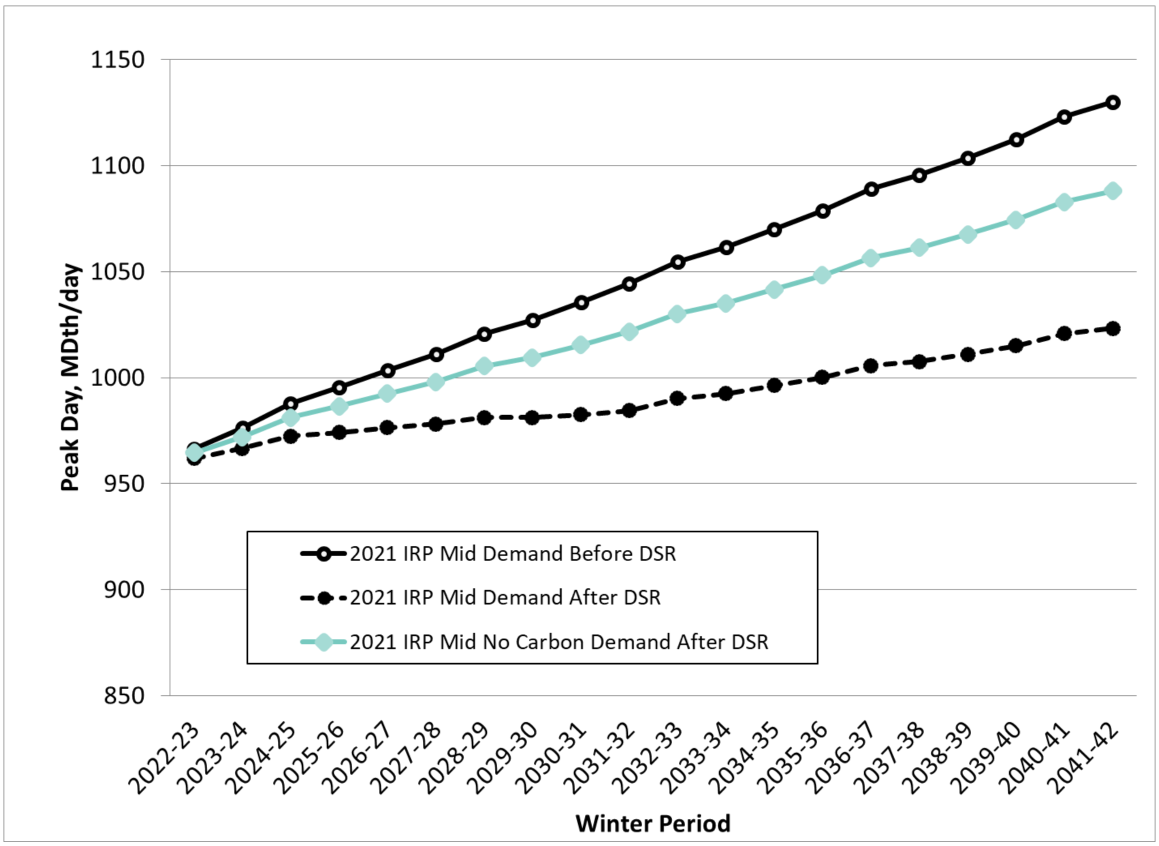


Key Findings by Resource Type

Demand-side Resources

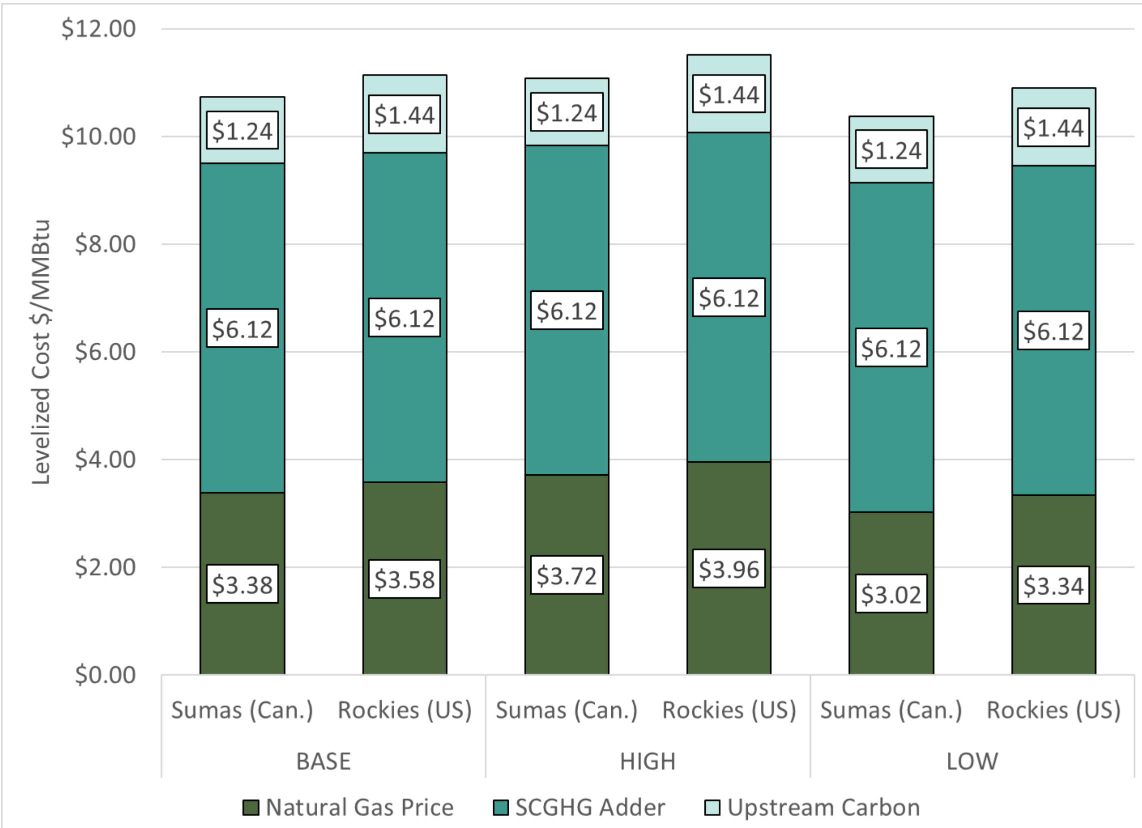
Cost-effective DSR (conservation) does not vary across scenarios. In other words, the same level of conservation is chosen in all of the scenarios. The conservation is driven by the total natural gas costs, which now includes additional costs for upstream emissions, more than by other factors such as resource need. Figure 3-26 shows the results of cost-effective DSR for the Mid Scenario with and without the carbon adders, and that the amount of cost-effective DSR is significantly lower when the total cost of natural gas consists of only the natural gas commodity costs.

Figure 3-26: DSR Cost Effective Levels are Driven by Total Natural Gas Costs



Conversely, in Figure 3-27, When the carbon adders are included, the total cost of natural gas varies only slightly from one scenario to the next, and this results in the same level of DSR being selected in all three scenarios.

Figure 3-27: Total Cost of Natural Gas (Commodity + SCGHG + Upstream Emissions)



Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in the High scenario. The timing of the Swarr upgrade is driven by the load forecast. In the High load scenario, Swarr is needed by 2037/38. Upgrades to Swarr are essentially within PSE's ability to control, so PSE has the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, since expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. The Swarr upgrade has a short lead-time, and PSE has the flexibility to adjust it as the future unfolds.

Plymouth LNG

The Plymouth LNG peaker contract was selected as a least cost resource in the High Scenario. The plant is in PSE's electric portfolio, and the contract is up for renewal in April 2023, at which point the natural gas sales portfolio could buy the contract. In the High load scenario, the plant was selected to start service in the 2023/24 winter, and it has an associated pipeline capacity of 15 MDth per day on Northwest Pipeline to deliver the natural gas to PSE.

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines north to Station 2 is cost effective in the High Scenario, which adds 21 MDth/day in 2034/35, increasing to 30 MDth/day by the end of the planning horizon.

Resource Plan Forecast – Decisions

The forecast additions described above are consistent with the optimal portfolio additions produced for the Mid Scenario by the SENDOUT gas portfolio model. SENDOUT is a helpful tool, but its 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 Mid Scenario – the same as in the Low and High Scenarios. Natural gas prices appear to have little impact on DSR, regardless of the load growth forecast. The primary variable that affects the resource decision is the assumption for SCGHG adders. The SCGHG adders are derived from requirements stated in HB1257, which became law during the 2019 legislative session and require the SCGHG adders to be incorporated in the planning analysis as part of capacity expansion decisions. The results show that cost-effective conservation in the Mid Scenario is likely to be a safe decision, since the same level of conservation is cost effective regardless of whether the demand forecast is as low as the 10th percentile in the Low Scenario or as high as the 90th percentile in the High Scenario.

The level of cost-effective DSR found in the deterministic Mid, Low, and High Scenarios is a robust result. The stochastic analysis found this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly. Cost-effective DSR reduced both cost and risk in the natural gas portfolio according to the stochastic analysis. Therefore, the risk of over-building or under-building DSR appears to be low.

Supply-side Resources

The supply-side resources – Plymouth LNG peaker contract, Swarr, and pipeline expansions – represent the High Scenario resource additions. No supply-side resources are needed in the Mid and Low Scenarios. Even in the High Scenario, the only resource needed in the near term is the Plymouth LNG peaker contract. The lead time to acquire this resource contract is short, so no decisions are needed until at least 2022. Swarr and NWP plus Westcoast pipeline additions are needed only in the High Scenario in the back half of the study period, thus no decision will be required in the near term. There will be opportunities to review these resources in future IRP cycles before any decisions are necessary.

4. TECHNICAL MODELING ACTION PLAN

Since the 2017 IRP, PSE has made significant advancements in the analytical tools and methods used, and these advancements have been applied to the 2021 IRP. The improvements are documented throughout this IRP. PSE has also identified several improvements for future IRPs. These are described below.

ELECTRIC RESOURCE PLANNING

1. Adopt winter and summer resource adequacy analyses, and develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.
2. Evaluate the benefits and impacts of the regional resource adequacy program and integrate into PSE's resource planning if appropriate.
3. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
4. Evaluate technology solutions to reduce model run times for the electric portfolio and stochastic models.
5. Continue to refine energy storage modeling.
6. Explore transmission planning optimization tools to help understand the impacts of transmission in electric supply portfolio modeling.

NATURAL GAS RESOURCE PLANNING

1. Evaluate available natural gas portfolio models for long-term resource planning and implement new model for the 2023 IRP.
2. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
3. Evaluate the ongoing use of the existing natural gas peak day planning standard and study the impacts of changing the planning standard.

4 Planning Environment

This chapter reviews the conditions that defined the planning context for the 2021 IRP.

Contents

1. CLEAN ENERGY TRANSFORMATION ACT RULEMAKINGS

Since the passage of the Clean Energy Transformation Act (CETA) in 2019, several state agencies have been engaged in rulemakings to implement key provisions of the statute. These include the following.

1. The Washington Utilities and Transportation Commission (WUTC) – multiple topics, including the IRP, Clean Energy Implementation Plan (CEIP), and Purchase of Electricity rulemakings
2. The Department of Commerce (Commerce) – CETA rulemaking primarily for consumer-owned utilities
3. The Department of Health (DOH) – cumulative impact analysis
4. The Department of Ecology (Ecology) – unspecified emissions rate and energy transformation projects.

Each of these rulemaking efforts is summarized below. At the time of this writing, some topics remain unresolved in rulemaking and await further discussion and development in 2021.

WUTC CETA Rulemakings

The WUTC completed three rulemakings at the end of 2020 to implement CETA: the Energy Independence Act (EIA) Rulemaking, the IRP/CEIP Rulemaking, and the Purchase of Electricity Rulemaking.

EIA RULEMAKING*.* The EIA rulemaking revises certain provisions of existing EIA rules to align with CETA and defines key terms related to the low-income provisions of CETA in RCW 19.405.120, including “low income,” “energy assistance need” and “energy burden.”

IRP/CEIP RULEMAKING. The IRP/CEIP Rulemaking outlines the timing and processes associated with filing an IRP, a Clean Energy Action Plan (CEAP) and a Clean Energy Implementation Plan (CEIP). Among many other new requirements, utilities are directed to establish equity advisory groups to advise utilities on equity issues, including vulnerable population designation, equity customer benefit indicator development and recommended approaches for compliance with RCW 19.405.040(8) as codified in the rule.

PURCHASE OF ELECTRICITY RULEMAKING. The Purchase of Electricity Rulemaking outlines the timing and expectations for utilities when acquiring resources that are identified as a resource need in the IRP.

In addition, the WUTC anticipates further discussions and policy development in 2021 regarding the following issues through a subsequent Markets Work Group rulemaking as required in RCW 19.405.130 or other rulemakings or policy statements.

- Non-energy benefits and the cost-effectiveness test
- No-coal attestation under CETA
- Natural gas IRP rulemaking per HB 1257
- Policy guidance for implementing Section 12 low-income provisions of CETA
- Interpreting a utility's "use" of electricity to serve customers
- Incorporating DOH's Cumulative Impact Analysis (CIA) into utility planning processes

Department of Commerce CETA Rulemaking

The Department of Commerce (Commerce) is charged with developing rules for implementation of CETA for consumer-owned utilities. Additionally, Commerce is responsible for developing reporting procedures for all utilities, investor-owned and consumer-owned. Commerce published the final rules at the end of 2020.

Department of Commerce CETA Low-income Draft Guidelines and WUTC Low-income Policy Development

In early 2020, the Department of Commerce released draft guidelines to support the low-income reporting requirements that utilities must meet under RCW 19.405.120 (Section 12 of CETA). Utilities provided data related to energy assistance to Commerce pursuant to the guidelines issued on November 13, 2020.

Beginning July 31, 2021, utilities must provide to Commerce a biennial assessment of the following.

- Programs and mechanisms to reduce energy burden, including the effectiveness of those programs and mechanisms for both short-term and sustained energy burden reduction.
- Outreach strategies used to encourage participation of eligible households.
- A cumulative assessment of previous funding levels for energy assistance compared to funding levels needed to meet 60 percent of the current energy assistance need or increasing energy assistance by 15 percent over the amount provided in 2018, whichever is greater, by 2030; and 90 percent of the current energy assistance need by 2050.

This assessment also must include a plan to improve the effectiveness of the assessment mechanisms and strategies towards meeting the energy assistance need.

PSE anticipates that this biennial low-income energy assistance report to Commerce will be used to inform any energy assistance potential assessment that may be required in future IRP cycles.[1]

Department of Health Cumulative Impact Analysis

CETA directs DOH to develop a CIA of the impacts of both climate change and fossil fuels on population health, in order to designate highly impacted communities. The results of the CIA will be used to inform power utilities' planning in the transition towards cleaner energy. While DOH set out to carry out this work collaboratively with robust input from stakeholders through work group meetings and subcommittees, DOH's plans for stakeholder engagement were scaled back in 2020 after the onset of the COVID-19 pandemic. DOH released a final CIA tool in February 2021.

Under CETA, the CIA is an important tool for informing a utility's equity-related assessment in its IRP, as well as informing its Clean Energy Implementation Plans.

1 / See Draft WAC 480-100-620(3)(b)(iii), included as part of the UTC's IRP/CEIP Final Proposed Draft Rules published on December 4, 2020.

Department of Ecology Rulemaking

The Department of Ecology is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process for determining what types of projects may be eligible as “energy transformation projects” under CETA.

Ecology adopted a new rule on January 6, 2021 that establishes: 1) the default unspecified emissions factor in CETA; 2) a general process for determining eligible energy transformation projects; and 3) a process and requirements for developing standards, methodologies and procedures to evaluate energy transformation projects.

2. TECHNOLOGY CHANGES

Convergence of Delivery System Planning and Resource Planning

Traditionally, the focus of an integrated resource planning process has been to determine the lowest reasonable cost mix of demand- and supply-side resources needed to meet the total projected load and peak needs of its customers with an adequate reserve margin. In Washington state, the planning process is prepared under rules or requirements for an IRP and reviewed by state utility commissions.

The IRP process includes the cost of transmission and distribution infrastructure needed to connect and transmit the power from potential new generation sources; however, planning for the transmission and distribution delivery systems that ensure power can be delivered to end-use customers has traditionally been separate from the IRP process.

A variety of economic, technological and societal factors are changing the electric utility planning process and blurring the historical division between delivery system planning (DSP) and integrated resource planning. These include the increasing affordability of solar generation (including rooftop solar), the maturing of battery storage technology, electric vehicle adoption, advancements in customer management and information about electricity use, and advancements in the management and data systems used to integrate and control distributed energy technologies.

In the future, continued growth of customer solar generation and other distributed energy resources will contribute to meeting the overall resource need but will also lead to power being pushed back to a distribution feeder that was not designed for two-way power flows. This will require PSE to plan and build a grid that is different than today to capture the resource benefit effectively. The grid of the future needs to be safe, reliable, resilient, smart, clean and flexible.

Washington State's Clean Energy Transformation Act is also driving change. It recognizes that transforming the state's energy supply requires the modernization of its electricity system and that clean energy action planning must include any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities. Additionally RCW 19.280.100, resulting from House Bill 1126, furthers this connection as energy supply needs are met through distributed energy resources (DERs). It established a policy that guides how distributed energy resource planning processes are to occur in order to illuminate the interdependencies among customer-sited energy and capacity resources.

With this backdrop, PSE is in the process of increasing the coordination of delivery system planning with resource planning, as it provides benefits by bringing together solutions to address delivery system challenges while meeting resource needs. With the increasing maturity and feasibility of DERs, delivery system needs may be solved using these non-traditional solutions at local points or in certain areas of the delivery system. If these non-traditional resources decrease load (such as demand response programs) or provide a generation source (such as rooftop solar), they may also provide benefit to the overall energy supply resource portfolio. This creates a natural connection between DSP and energy supply resource planning.

Historically, the two planning processes have occurred on separate timelines. However, DERs installed in sufficient quantity to solve delivery system needs may change the results in the resource planning process, so coordinating the two benefits both processes and analyses.

A coordinated process must accommodate:

- customer-owned resources and electric vehicles
- programs such as distribution automation and demand response
- distributed energy resources
- energy storage
- energy efficiency strategies

In addition to incorporating the cost of transmission and distribution infrastructure, the IRP and DSP processes use some of the same core information in different ways. Data flows from one process to the other at different steps as shown in Figures 4-1 and 4-2.

The confluence of technology, customer adoption, grid integration capability and solution effectiveness will drive the pace of interconnecting the DSP and IRP processes.

Figure 4-1: Data Flows between Delivery System Planning and Integrated Resource Planning

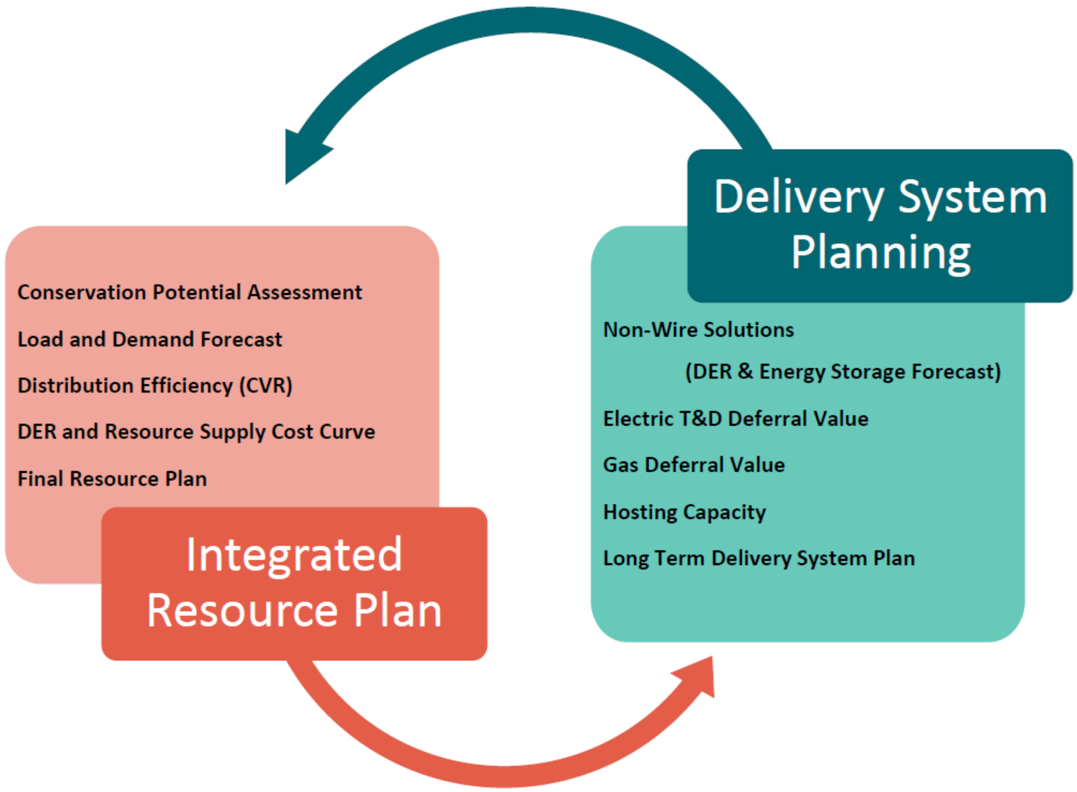


Figure 4-2: Data Flows between Delivery System Planning and Integrated Resource Planning (Table)

IRP Outputs in the DSP	Conservation Potential Assessment	Decreases county-level system capacity needs
	Load and Demand Forecast	Decreases county-level system capacity needs
	Distribution Efficiency (CVR)	Decreases capacity needs where implementable and may be a solution alternative
	DER and Resource Supply Cost Curve	Cost supply curve including different types of DER resources which could be used as non-wire solution alternatives if located appropriately
	Final Resource Plan (including DER's)	Insight for participation in resource acquisition process for DERs to enhance locational value opportunities and informs enabling grid modernization requirements
DSP Outputs in the IRP	Non-wire Solutions (DER & Energy Storage Forecast)	Decreases overall resource need by identifying must-take DER resources to meet specific transmission and distribution delivery needs
	Electric T&D Deferral Value	Provides a quantitative value of past T&D investments to use in the conservation potential assessment
	Gas Deferral Value	Provides a quantitative value of past investments to use in the conservation potential assessment
	Hosting Capacity (future)	Future input for economic opportunities
	Long-term System Delivery Plan	Future input for opportunities and constraints that should be considered

New Fuel Technologies

Renewable Natural Gas

Renewable natural gas (RNG) is pipeline quality biogas that can be used as a substitute for conventional natural gas streams. Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. The American Biogas Council ranks Washington 22nd in the nation for methane production potential from biogas sources, with the potential to develop 128 new biogas projects within the state. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

RNG is not yet produced at utility-scale in this region and will require developing both supply sources and an infrastructure to deliver that supply to utilities. RNG will most likely be directed toward natural gas utilities before being used as a generation fuel. The electric sector has access to a more mature set of renewable options than the natural gas sector; these include hydro, wind, solar, geothermal and energy storage systems that can capture surplus energy. Natural gas utilities have very few options to decarbonize, so as natural gas utilities begin decarbonizing their systems in earnest, markets will probably pull RNG to natural gas utilities before it is used broadly as generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is mostly used as a transportation fuel because of federal and state programs such as the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, the existing natural gas distribution network can be used to deliver renewable fuel.

HB 1257 became effective in July, 2019, and PSE is working with the WUTC and other stakeholders to develop guidelines to implement its requirements. However, recognizing the competitive nature of the existing RNG market, PSE concluded that there would be an advantage to be a first-mover. To that end, PSE conducted a RFP to determine availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of Tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in the first half of 2021. RNG supply not utilized in

PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

In addition, PSE has a current offering called Carbon Balance which provides residential natural gas customers the choice to purchase blocks of carbon offsets for a fixed price. The program provides customers with a way to reduce their carbon footprint through the purchase of third-party verified carbon offsets from local projects that work to reduce or capture greenhouse gases.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. Because of RNG's significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for generic analysis. The benefits of RNG are measured primarily in terms of CO_2e reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Avoided pipeline charges realized by connection of acquired RNG directly to the PSE system will be considered, but are not significant, relative to the cost of the RNG commodity. Contract RNG purchases present known costs, however, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, PSE is not prepared to discuss specific potential RNG projects in a public environment. Individual projects will be analyzed and documented as PSE pursues additional supplies.

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's gas system, annually. PSE is planning significant further investments in cost-effective RNG supplies and continues to believe there is value in being a proactive RNG buyer and/or producer in the region. PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future Voluntary RNG Program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. In order to meet the expectations within the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

Biodiesel

Biodiesel is defined as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old growth or first-growth forests. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or from dedicated crops. According to the U.S. Energy Information Administration, there are two facilities in Washington state that make biodiesel, which together can manufacture upwards of 100 million gallons of biodiesel a year.[2] Biodiesel may become crucial in the future as a fuel supply for combustion turbines. These units would be the same basic generator as a natural gas combustion turbine, but instead of burning natural gas with petroleum diesel as a backup fuel, the generator would burn renewable natural gas with biodiesel as the backup fuel. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At full capacity, a 237 MW frame peaker would require approximately 25,000 gallons of biodiesel per hour. At this fuel feed rate, a facility would require about 1.2 million gallons of biodiesel storage to continuously fire for a 48-hour peak event. Existing Washington state biodiesel production could plausibly supply several combustion turbines intended to supply reliable capacity during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low hydro conditions.

Biodiesel use in simple-cycle combustion turbines is explored in this IRP. An analysis of the amount of fuel needed is in Chapter 7, Resource Adequacy Analysis, and the results of the portfolio optimization are in Chapter 8, Electric Analysis.

Hydrogen

Renewable hydrogen, also known as power-to-gas, is a process by which excess renewable electricity can be transformed (by splitting hydrogen from water) into hydrogen, or, if combined with carbon, synthetic natural gas. These fuels can then be stored utilizing existing natural gas pipeline infrastructure to more cost effectively shift seasonal supply when mismatched with demand.

PSE is a founding member of the Renewable Hydrogen Alliance (RHA). The RHA promotes using renewable electricity to produce climate-neutral hydrogen and other energy-intensive products to supplant fossil fuel consumption. This group is instrumental in keeping PSE up to date on industry developments.

Hydrogen or its derivatives can be used to reduce the GHG content of gas for gas utilities. Renewable hydrogen can be injected into the existing pipeline infrastructure. The amount of hydrogen that can be blended into the pipeline system with natural gas is limited, because hydrogen is less energy dense than current standards for pipeline quality gas. That means a cubic foot of hydrogen has less energy than a cubic foot of natural gas. Pipeline systems are required to maintain heat content within predetermined ranges for safety reasons. Natural gas-consuming equipment and appliances are designed to use a certain amount of gas per unit of

2 / *https://www.eia.gov/biofuels/biodiesel/capacity/*

time, so the gas feeding that equipment needs to maintain these standards. Currently, it appears the ratio of hydrogen that could be injected into the system is about 20 percent.

Hydrogen can also be used as a fuel in gas combustion turbines – both simple-cycle and combined-cycle plants. The hydrogen can be blended into the upstream natural gas supply and delivered on existing infrastructure, based on the physical safety limits described above for gas utilities. Hydrogen can also be injected directly into combustion turbines or blended in higher ratios than 20 percent, if the hydrogen manufacturing, storage and delivery infrastructure is built.

A significant challenge for hydrogen is cost. Today, gray hydrogen (hydrogen manufactured with fossil fuel energy) sells for about $2 per kilogram delivered to a few key chemical market hubs, which translates to about $17.6 per MMBtu for natural gas.[3] While green hydrogen may use surplus renewable electricity that may cost less on a dollars per MWh basis, the output of a hydrogen manufacturing facility using only surplus renewable energy will be less, which will drive up the average cost per unit.

For this IRP, PSE explored hydrogen as an alternative fuel source for the combustion turbines. Though manufacturers have done extensive development for a hydrogen-fueled combustion turbine, it was difficult to get a price forecast for the fuel. Also, the modeling techniques are not available to model hydrogen as both a storage for renewable energy and a fuel for the combustion turbines. PSE will continue to explore hydrogen as a fuel source for combustion turbines and new modeling techniques for future IRPs.

3 / See S&P Global at: https://www.spglobal.com/ratings/en/research/articles/201119-how-hydrogen-can-fuel-the-energy-transition-11740867#:~:text=S%26P%20Global%20Ratings%20believes%20hydrogen,and%20massive%20growth%20of%20renewables.&text=A%20Hydrogen%20Council%20report%20suggests,primary%20energy%20supply%20by%202050

3. WHOLESALE MARKET CHANGES

Prices, Volatility and Liquidity / August 2020 Supply Event

Wholesale electricity prices in the Pacific Northwest remain, on average, relatively low. In recent years, however, these relatively low prices have been punctuated by periods of high volatility and limited market liquidity.

On August 17, 2020, in the middle of a heat wave affecting the western U.S., the region's reliability coordinator declared an Energy Emergency Alert for PSE and four other grid operators in the WECC, indicating these entities risked not having sufficient energy supply to meet their load and reliability obligations. Wholesale market dynamics and reliance on energy transfers from neighboring entities were key factors in how this event developed in the Northwest. In the day-ahead market, power prices at the Mid C hub spiked to more than five times what they were just days earlier. Offers to sell power at Mid C disappeared as available supply flowed to even higher priced delivery points in California and the desert southwest. By Monday August 17, 2020, forecasted load had increased with higher temperatures, but additional supply in the Mid C real-time market was extremely scarce. For the highest load hours of the day PSE was unable to procure power at any price. In California, the situation was even more severe, and in the days leading up to August 17, 2020, CAISO implemented rolling black-outs in order to maintain grid stability.

In its report on the August 2020 event, CAISO identifies extreme heat resulting from climate change and the evolving mix of generation resources as primary factors leading to insufficient supply conditions. As extreme temperatures become more common and traditional thermal resources continue to be replaced with variable renewable resources, high price volatility and the risk of unavailable supply are likely to be more prevalent in western U.S. wholesale power markets.

Market Developments / CAISO EDAM

In late 2018, CAISO engaged stakeholders to examine the feasibility of extending participation in its day-ahead market to entities already participating in the energy imbalance market (EIM). Potential benefits of an extended day-ahead market (EDAM) include production cost savings through more efficient use of available transmission, more efficient day-ahead unit commitment, and the creation of day-ahead base schedules at hourly granularity; diversity of imbalance reserves; and environmental benefits including reduced curtailment of renewable resources. EDAM would operate in a framework similar to EIM's approach to the real-time market, which does not require full integration into the California ISO balancing area. Participating entities and their regulatory authorities would remain responsible for transmission planning, resource adequacy and balancing area control performance.

A feasibility assessment completed near the end of 2019 identified significant benefits associated with the EDAM proposal, and stakeholder entities have since started work on more specific market design criteria. Evaluation of topics including governance, resource sufficiency requirements and the distribution of market benefits has been ongoing throughout 2020, and a final market design proposal is expected in late 2021.

4. REGIONAL RESOURCE ADEQUACY

Utilities across the Northwest have partnered to explore a potential regional resource adequacy program. Resource planning in the Northwest is currently done on a utility-by-utility basis, typically through integrated resource planning processes. This utility-by-utility planning framework has worked well for the region during times when the region was surplus capacity. As large amounts of firm generators retire and several regional studies point to a capacity deficit in the next decade, utilities have growing concerns about whether the new capacity needed to maintain regional reliability can be procured in a timely manner. A Northwest resource adequacy program would offer two key benefits: reliability and cost savings. First, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Resource adequacy programs do this by establishing transparent processes to assess, allocate and procure a region's resource needs. Second, a regional resource adequacy program would enable cost savings. By planning for the peak demand of the entire region (the coincident peak demand) instead of each utility's individual (non-coincident) peak demand, a regional approach would produce an overall lower capacity need and therefore a reduced level of investment. Furthermore, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand.

Resource adequacy programs deliver these benefits by establishing transparent, coordinated calculations of required capacity and offering mechanisms for sharing resources among participants. A resource adequacy program in the Northwest would help the region navigate reliability and cost challenges given its evolving resource mix.

In late 2019, NWPP members initiated a resource adequacy program design development process. In mid-2020, the NWPP Resource Adequacy Program Conceptual Design was completed and Southwest Power Pool (SPP) was hired to lead the detailed design in partnership with the NWPP members. At the time of this writing, the detailed design is underway, and the process is expected to conclude in mid-2021. The timeline for the overall resource adequacy program implementation is estimated to be in 2024. PSE is actively involved in the design development process and looks to leverage program benefits. Future IRPs will need to incorporate the RA program into its resource adequacy analysis and overall planning process.

5. FUTURE DEMAND UNCERTAINTY FACTORS

Electric Vehicles

Electric vehicles (EVs) are rapidly gaining a presence in PSE's service territory and taking hold in every vehicle market. These EVs include light-duty vehicles, medium-duty vehicles, and heavy-duty vehicles, both cars and trucks, and they are operated by individuals and as members of fleets. EVs create new electric load, and the pace and scale of EV adoption is key to the magnitude of these impacts on utility demand. PSE contracted for an EV sales and load forecast, which was then incorporated into the 2021 IRP Demand Forecast. This forecast revealed new opportunities to manage EV load and improve customer experience, which PSE is investigating through a suite of EV pilot programs.

The 2021 IRP Base Demand Forecast incorporates GuideHouse's incremental EV energy forecast by excluding demand from existing vehicles. See Chapter 6, Demand Forecasts, for a discussion of base energy demand and peak impacts.

Demand Impacts

The Electric Vehicle Charger Incentive (EVCI) Pilot Program, which went into effect on May 1, 2014, allowed PSE to offer a $500 rebate to customers who purchase their own Level 2 electric vehicle charger.[4] Using data gathered through this pilot, PSE created an "Electric Vehicle Household and Charger Load Profiling" study with a study period set for 12 months ending June 2017. At the time, there were an estimated 13,140 EVs registered in PSE's electric service territory, of which 9,480 were 100 percent battery-operated (BEV) and 3,660 were plug-in hybrid vehicles (PHEV).[5]

The key findings of the study were as follows:

- On a typical weekday, hourly load per Level 2 EV charger varied between 0.1 kW and 0.9 kW while hourly load per Level 1 charger ranged between 0.06 kW and 0.6 kW.[6]
- On a typical weekend day, hourly load per Level 2 charger ranged between 0.08 kW and 0.6 kW while the range of hourly load per Level 1 charger was 0.04 kW to 0.5 kW.

4 / Docket UE-131585
5 / A list of EV's registered through the end of June 2017 was provided by Washington State Department of Licensing.
6 / The average hourly load per EV charger should not be interpreted as the hourly energy use by a typical EV charger. For example, a typical Level 2 charger uses between 1.1 kW and 2.6 kW while in use and close to zero while not in use. An individual L2 charger load shape would be characterized by a flat load at nearly zero kW for most of the day interrupted by one or more charging events which last a few hours or so per event.

- Daily peak of EV charger load occurred mostly in the early evening hours of 6:00 PM to 8:00 PM, as does monthly system peak demand.
- Monthly load factor and system coincidence factor of EV charger loads are fairly low for most months. During the study period, all of the monthly load factors were below 0.29 while 8 of 12 monthly system coincidence factors were lower than 0.40. However, the system coincidence factor will become very high if monthly system peak and EV charger peak loads occur on the same day, as happened in March 2017 when the system coincidence factor was 0.91.

Although at the time of this study EVs represented a very small portion of the residential class load, PSE predicts that by 2032 there will be more than 250,000 Light Duty EVs in PSE's service territory.

To study the implications of this growing load that can be added anywhere and potentially coincident with peak, PSE's Up & Go Electric programs are actively working to develop load shapes for additional charging use cases that are specific to PSE's electric service territory. This suite of pilot programs is expanding to include workplace charging, multi-unit dwellings, public charging, many unique low-income use cases, a more refined load profile for single-unit dwelling charging, and to capture a broader audience for each of these use cases. The programs will also develop load profiles for prominent medium and heavy duty vehicle charging use cases.

In addition to developing load shapes, a key goal of PSE's Up & Go Electric program is to investigate the most effective and efficient ways of encouraging and enabling EV customers to shift charging to off-peak hours in a way that minimizes demand-side impacts. These programs are ongoing and final results are not yet available, but PSE has already applied some of the early lessons learned to the design of future programs to ensure that customer load is managed not only to reduce coincidence with system peak, but also to minimize the coincidence of charging between EV chargers.

Energy Efficiency Technology, Codes and Standards and Electrification

Changing codes and standards and energy efficiency technology are impacting both customer choices and energy efficiency programs.

In terms of energy efficiency programs for example, when federal minimum lighting performance standards included screw-in LED lighting, this removed LEDs from energy efficiency program offerings; while LEDs continue to achieve savings, they could no longer be included in incentive programs.

The two energy codes that impact PSE customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to include a focus on carbon emissions in addition to energy efficiency, and these changes emphasize electrification of systems formerly fueled by natural gas. Since 2018, the WSEC no longer gives builders efficiency credits for new single family homes that install natural gas space heating or water heating, instead giving them credits for installing heat pumps for space and water. In 2021, the Seattle Energy Code put significant barriers on using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will be using various types of heat pump technology to attempt to meet the loads of these systems.

While technology continues to provide innovation in how loads are met in customer homes and buildings, it takes time for these changes to gain significant market penetration. Heat pump water heaters, for example, have been on the market for nearly a decade, but they are largely limited to the new home market rather than the much larger existing home market. When code changes move quickly, adoption issues arise and may include: the lack of robust examples/applications that have validated particular approaches (such as the sole use of heat pumps to serve both space and water heating in large-demand applications, essentially new building electrification); the complexity of the design, operation and maintenance of systems that have been largely hands-off traditionally; and the installer community not being fully prepared to transition to installing and maintaining these systems. Time is required to work out design flaws, build trust in the installer/trades community, and drive down costs so that consumers will pay reasonable costs to make these changes.

Despite how quickly changes are taking place in the areas of technology and codes and standards, PSE remains committed to ensuring its customers are made aware of the opportunities to reduce energy use and carbon footprints, advocating for smart changes to codes and standards and working with our trade allies to understand and mitigate barriers to new technology adoption.

Distributed Energy Resources

DER-based generation, such as rooftop solar panels, has seen price declines and increases in customer adoption. The technology and its rate of adoption are still evolving, and therefore future demand can be significantly impacted by policy, including incentives, and technological advances, including further price declines.

While PSE customer adoption of DER is low when compared to states like California and Hawaii, PSE residential solar is increasing by about 2,000 customers annually. Additionally, the average capacity of residential solar is increasing. In 2009, the average residential capacity was 4.7 kW, while the current average system generating capacity is 10 kW. As of the end of 2020, PSE's system hosted 85 MW of net metered solar, with over 10,100, or about 1 percent, of customers participating. In comparison, solar represents about 25 percent of Hawaii's generation capacity and over 10 percent of its residential customers have solar generation.

Adding increasing volumes of DERs to the distribution system, whether they are generating technologies such as solar, storage technologies such as batteries, or load management tools, requires rethinking how the distribution system operates and what standards and controls are needed to maintain the safety and reliability of the system. Demand will be impacted by when and how these technologies operate, whether dependably and reliably decreasing load or intentionally increasing load if charging is allowed during peak hours.

Additionally, most customers pursing DER solutions today do not consume all of the energy they generate on-site in real time, making demand and power flow more variable on the local distribution system and resource management overall. Storage and control systems promise improvement in managing DERs' benefits and impacts on demand, and over 4 percent of PSE's net metered solar installations include battery storage today. These emerging capabilities are maturing, and as monitoring, control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to understand real demand impacts will increase.

For this IRP, PSE explored and modeled numerous future DER options; these are documented in Chapters 5 and 8.

6. NATURAL GAS SUPPLY AND PIPELINE TRANSPORTATION

Risks to Natural Gas Supply

Natural gas is imported to the Pacific Northwest, primarily from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure, therefore, present a risk to reliable gas supply in the region.

In October 2018 the Westcoast Pipeline, a major pipeline that brings natural gas from British Columbia south to the U.S. border, ruptured, severely limiting the supply of natural gas to the Pacific Northwest. Through a combination of immediate conservation efforts, the shutdown of natural gas fired power plants, and curtailment of service to select industrial customers, the region only narrowly avoided destabilization of the natural gas transportation system and curtailment of service to large swaths of natural gas customers.

Capacity restrictions on the Westcoast Pipeline continued well into 2019 causing a dramatic increase to wholesale natural gas prices in the region. By late 2019, the pipeline had been restored to normal full capacity, and while average gas prices have generally returned to pre-event levels, prices remain significantly more volatile compared to recent historical periods.

The lessons learned from the October 2018 event were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). The Agreement is made among entities that utilize, operate and control natural gas transportation and/or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada and Idaho). The Agreement[7] is intended to define the terms and conditions for cooperation and/or assistance between the parties in an emergency if such aid is volunteered. Another objective is to maintain and improve communication linkages between the members as they pertain to emergency planning and incident response.

7 / https://www.westernenergy.org/nwmaa/

7. PURCHASING VERSUS OWNING ELECTRIC RESOURCES

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan, as well as the acquisition process. The formal Request for Proposal (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 resource build decisions should also be considered when making prudent resource acquisition decisions.

In Build versus Buy, "Build" refers to resource acquisitions that involve PSE ownership of an asset. Ownership could occur anywhere along the development life cycle of a project. PSE could complete development activities from the beginning or buy the asset anywhere from early stage development to Commercial Operation Date (COD) or after. "Buy" refers to purchase of the output of a project through a Power Purchase Agreement (PPA).

In general, quantitative and qualitative evaluations for Build and Buy proposals are conducted similarly in an RFP, consistent with WAC 480-107, solving for the lowest cost options for customers. Qualitative project risks are evaluated in the same way for both kinds of acquisitions. Quantitative evaluations for Build options include costs of ownership such as operating expenses and depreciation. These are typically embedded in the MWh price for PPAs. Build proposals include the allowable rate of return on capital assets as a cost to customers, while Buy proposals include a return on the PPA costs as allowed by the Clean Energy Transformation Act. Project designs also need to be more carefully scrutinized for projects that PSE would own and operate. Equipment selection and design specifications must meet PSE standards for ownership.

In the 2018 RFP, PSE received a large number of ownership proposals. These proposals included offers for PSE to take ownership of projects before COD, at COD and after COD. Primarily because of the fact that PSE cannot monetize federal tax incentives for renewable projects, these proposals were not competitive relative to PPAs.

2021 PSE Integrated Resource Plan

5 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 how different resources or environmental regulations impact the portfolio.

5 Key Analytical Assumptions

Contents

1. OVERVIEW

This chapter describes the forecasts, estimates and assumptions that PSE developed for the electric and natural gas IRP analysis. The details of the electric and natural gas analyses can be found in Chapters 8 and 9, respectively, and further details are available in various appendices.

Section 2, Electric Analysis, presents the electric scenarios created to test how different sets of economic conditions affect portfolio costs and risks, followed by the inputs used to create those scenarios. Scenario inputs include the IRP demand forecast; price assumptions for natural gas and CO_2 costs; assumptions about cost and characteristics for existing and generic resources; and transmission considerations.

Electric portfolio sensitivities are described next. Sensitivities start with the optimized, least cost Mid Scenario portfolio produced in the scenario analysis and change a resource, environmental regulation or other condition to examine the effect of that change on the portfolio. PSE analyzed 27 sensitivities for the electric analysis.

Section 3, Natural Gas Analysis, is organized similarly. The natural gas scenarios are described first, followed by the inputs used to create the scenarios, then the sensitivities used to examine the effects of changes on the Mid Scenario portfolio. PSE analyzed six sensitivities for the natural gas analysis.

Each section also describes the delivery system planning assumptions for its respective energy delivery system.

Time horizon: The time horizon for the 2021 IRP is 2022 – 2041. The natural gas analysis analyzes the time frame 2022 – 2041, but the electric analysis has been expanded to analyze the time frame 2022 – 2045 to better understand the implications of CETA.

2. ELECTRIC ANALYSIS

Electric Price Forecast Scenarios

PSE created three scenarios for the electric analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources. PSE also added two scenarios to test how different carbon pricing can impact electric prices. The five electric price scenarios are outlined in Figure 5-1 and summarized below. A description of the economic inputs to the scenarios follows.

Figure 5-1: 2021 IRP Electric Price Forecast Scenarios

	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
4	SCGHG as Dispatch Cost	Mid	Mid	Social cost of greenhouse gasses modeled as federal CO_2 price across the WECC	Washington CETA, plus all regional RPS regulations in the WECC
5	CO_2 tax	Mid	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: $15/ton in 2022 increasing at $10/year across the WECC	Washington CETA, plus all regional RPS regulations in the WECC

NOTE
1. Mid demand refers to the 2021 IRP Base Demand Forecast.

Scenario 1: Mid

The Mid Scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[1] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[2] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

1 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

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

Scenario 2: Low

This scenario models weaker long-term economic growth than the Mid Scenario. Customer demand is lower in the region and in PSE's service territory.

DEMAND

- The 2021 IRP Low Demand Forecast is applied for PSE.
- Electric power price modeling: To extrapolate a low demand forecast for the WECC, the difference between the low and medium demand forecast in the Pacific Northwest from the NPCC 2019 Policy Update to the 2018 Wholesale Electricity forecast is applied to the WECC region medium forecast.

NATURAL GAS PRICES

- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Scenario 3: High

This scenario models more robust long-term economic growth than the Mid Scenario, which produces higher customer demand in the region and in PSE's service territory.

DEMAND

- The 2021 IRP High Demand Forecast is applied for PSE.
- Electric power price modeling: To extrapolate a high demand forecast for the WECC, the difference between the high and medium demand forecast in the Pacific Northwest from NPCC 2019 Policy Update to the 2018 Wholesale Electricity forecast is applied to the WECC region medium forecast.

NATURAL GAS PRICES

- Natural gas prices are higher as a result of increased demand; the Wood Mackenzie long-term high forecast is applied to natural gas prices.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Scenario 4: SCGHG as Dispatch Cost

The social cost of greenhouse gases (SCGHG) as Dispatch Cost Scenario models a federal CO_2 tax that effects all WECC states. This electric price forecast will be used for portfolio sensitivity J, SCGHG as a Dispatch Cost in Electric Prices and Portfolio.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[3] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a CO_2 price across all WECC states.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[4] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

3 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

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

Scenario 5: CO_2 Tax

The CO_2 tax scenario models a federal CO_2 tax plus the SCGHG adder for Washington. This electric price forecast will be used for portfolio sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[5] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices applied to all WECC states.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[6] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

5 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

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

Comparison Electric Price Scenario for CETA Rate Impact Cost Control

The rate impact cost controls in the Clean Energy Transformation Act (CETA) are calculated based on incremental costs associated with CETA compliance. Because a comparison to the base assumptions without CETA is required to estimate these incremental costs, PSE also developed a version of the Mid Scenario that does not include CETA. This electric price scenario will be used for the two cost comparison sensitivities without CETA described in Figure 5-26.

Figure 5-2: Comparison Electric Price Scenario for CETA Rate Impact Cost Control

COMPARISON SCENARIO FOR CETA RATE IMPACT COST CONTROL					
	Scenario Name	Demand	Gas Price	CO_2 Price	RPS/Clean Energy Regulations
	Mid + No CETA	Mid[1]	Mid	CA AB32 CO_2 policy	RCW 19.285, plus all regional RPS regulations in the WECC

NOTE
1. Mid demand refers to the 2021 IRP Base Demand Forecast.

Mid + No CETA

This scenario is for comparison purposes only; it is not part of the resource plan.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[7] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE

- CO_2 prices for California are included.

CLEAN ENERGY/RPS REGULATIONS

- Per RCW 19.285, 15 percent of Washington state energy is supplied by renewable resources by 2020; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied.

7 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

Electric Scenario Inputs

PSE Customer Demand

The 2021 IRP Base, Low and High Demand Forecasts used in this analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period.[8] Significant inputs include the following.

- 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

Figure 5-3 and Figure 5-4 below show the electric peak demand and annual energy demand forecasts without including the effects of conservation. The forecasts include sales (delivered load) plus system losses. The electric peak demand forecast is for a one-hour temperature of 23° Fahrenheit at Sea-Tac airport.

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 to be developed. By the time the IRP is completed, PSE may 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.

*> > > **See Chapter 6, Demand Forecasts,** for detailed discussion of the demand forecasts, and **Appendix F, Demand Forecasting Models,** for the analytical models used to develop them.*

8 / *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 service territory than others.*

Figure 5-3: 2021 IRP Electric Peak Demand Forecast – Low, Base (Mid), High

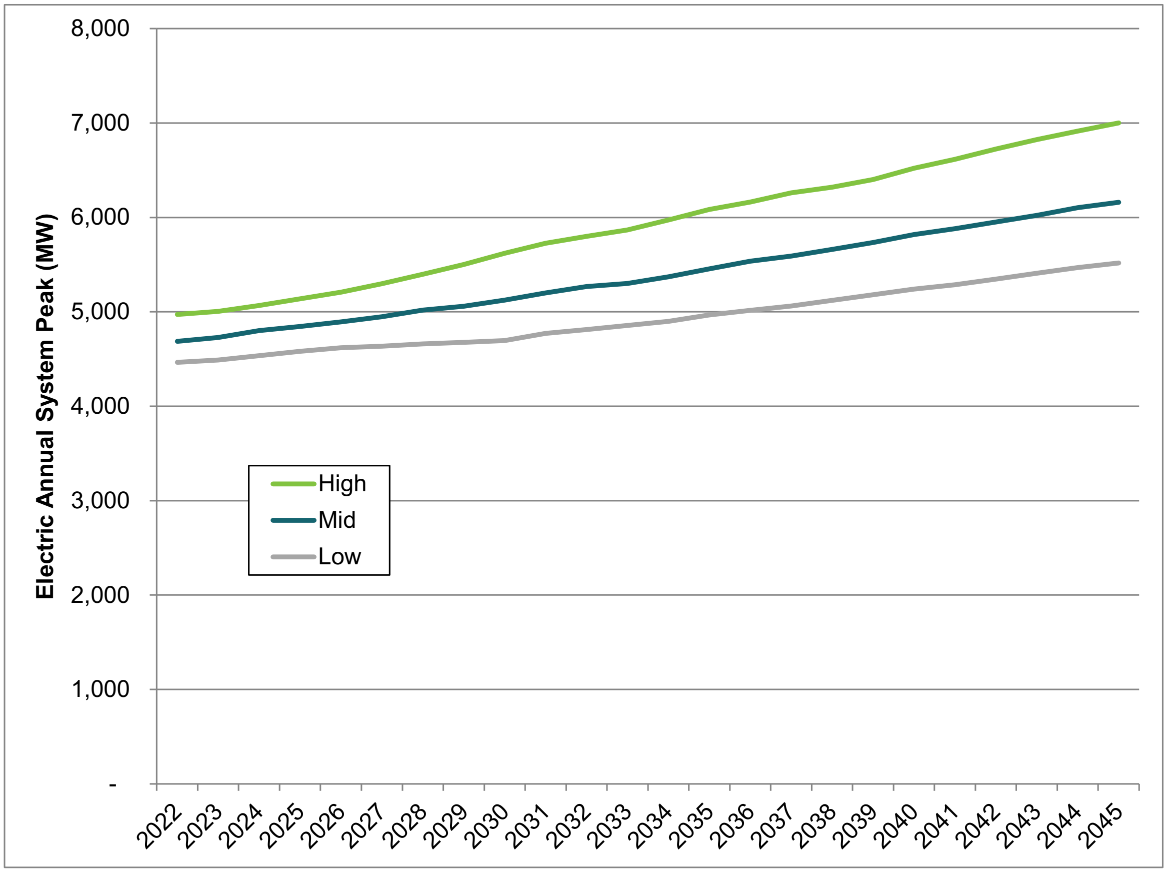
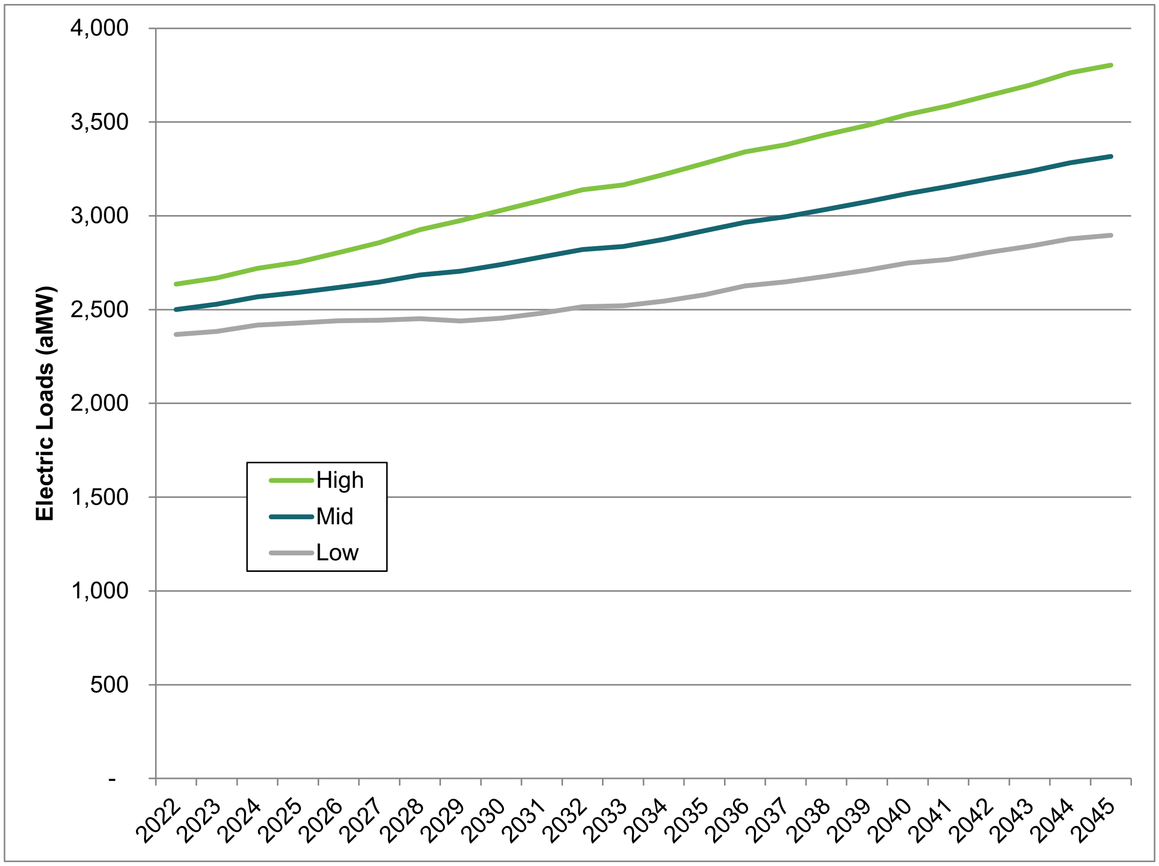


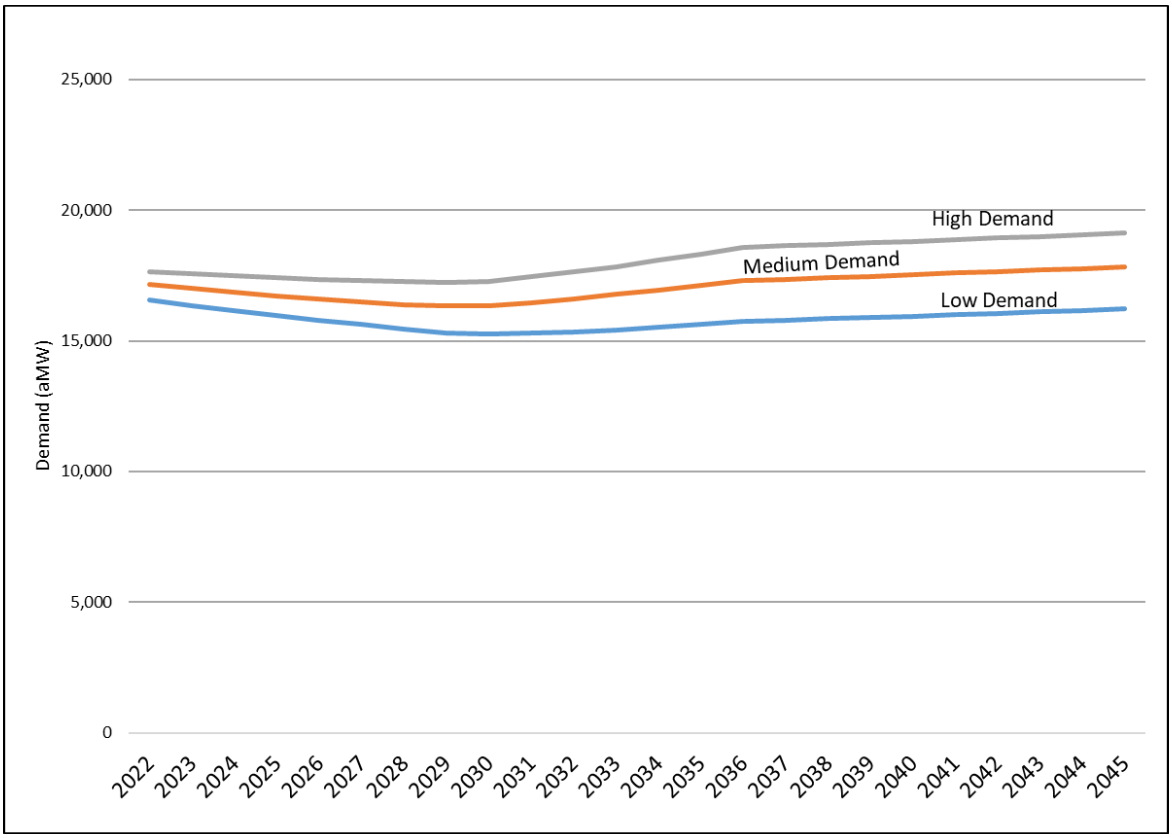
Figure 5-4: 2021 IRP Annual Electric Energy Demand Forecast - Low, Base (Mid) High



Regional Electric Demand

Regional demand must be taken into consideration because it significantly affects power prices. This IRP uses the regional demand developed by the NPCC[9] 2019 Policy Update to the 2018 Wholesale Electricity forecast, the most recent forecast available at the time of this analysis. Updated 2020 loads and COVID-19 impacts were not available from the NPCC until February 2021. Regional demand is used only in the WECC-wide portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Figure 5-5: NPCC Regional Demand Forecast for the Pacific Northwest – Average, not Peak



9 / 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.

Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[10] from Wood Mackenzie.[11]

- From 2022-2026, this IRP uses the three-month average of forward market prices from June 30, 2020. Forward market prices reflect the price of natural gas being purchased at a given point in time for future delivery.
- Beyond 2029, this IRP uses the one of the Wood Mackenzie long-run natural gas price forecasts published in July 2020.

For the years 2027 and 2028, a combination of forward market prices from 2026 and selected Wood Mackenzie prices from 2029 are used to minimize abrupt shifts when transitioning from one dataset to another.

- In 2027, the monthly price is the sum of two-thirds of the forward market price for that month in 2026 plus one-third of the 2029 Wood Mackenzie price forecast for that month.
- In 2028, the monthly price is the sum of one-third of the forward market price for that month in 2026 plus two-thirds of the 2029 Wood Mackenzie price forecast for that month.

Three natural gas price forecasts are used in the scenario analyses.

MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie low price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

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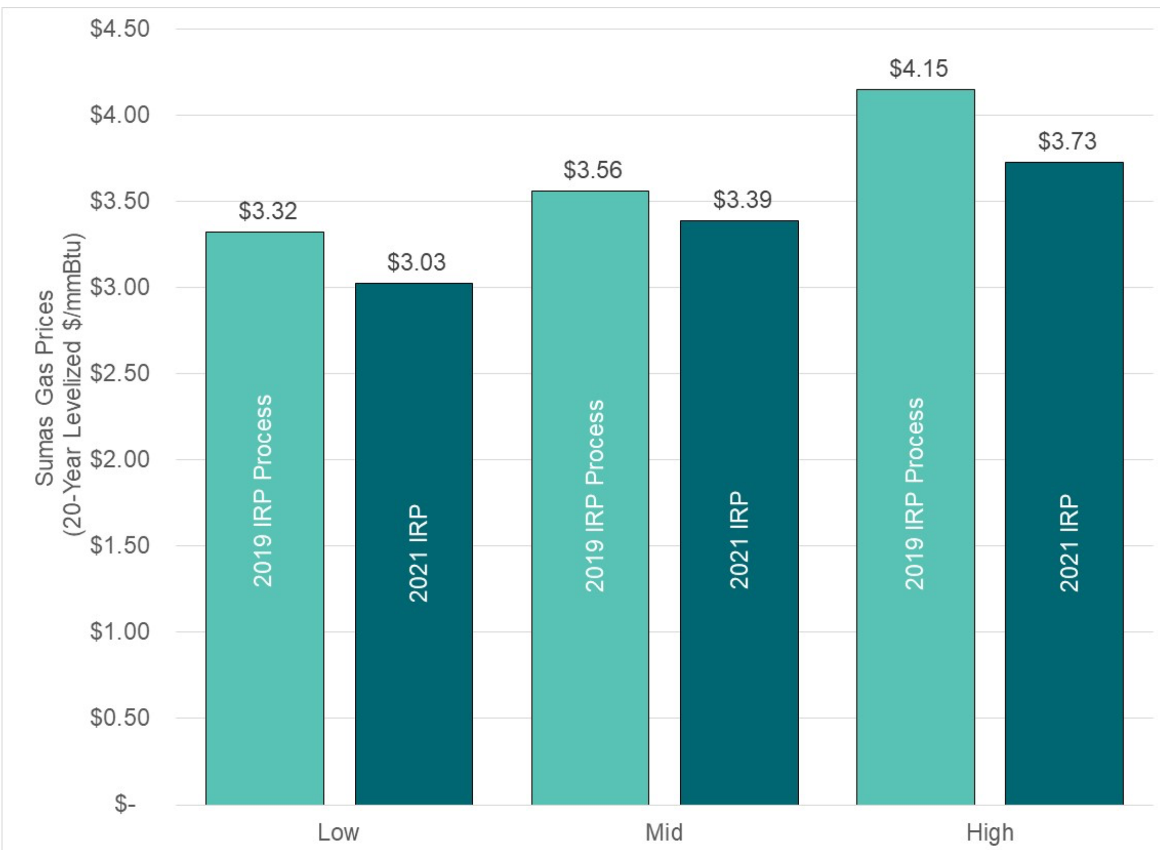
10 / *The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.*
11 / *Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.*

HIGH NATURAL GAS PRICES. The high natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie high price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

Figure 5-6 below illustrates the range of 20-year levelized natural gas prices used in this IRP analysis compared to the 20-year levelized natural gas prices used in the 2019 IRP Process.

Figure 5-6: Levelized Natural Gas Prices Used in Scenarios, 2021 IRP vs. 2019 IRP Process
(Sumas Hub, 20-year levelized 2022-2041, nominal $)



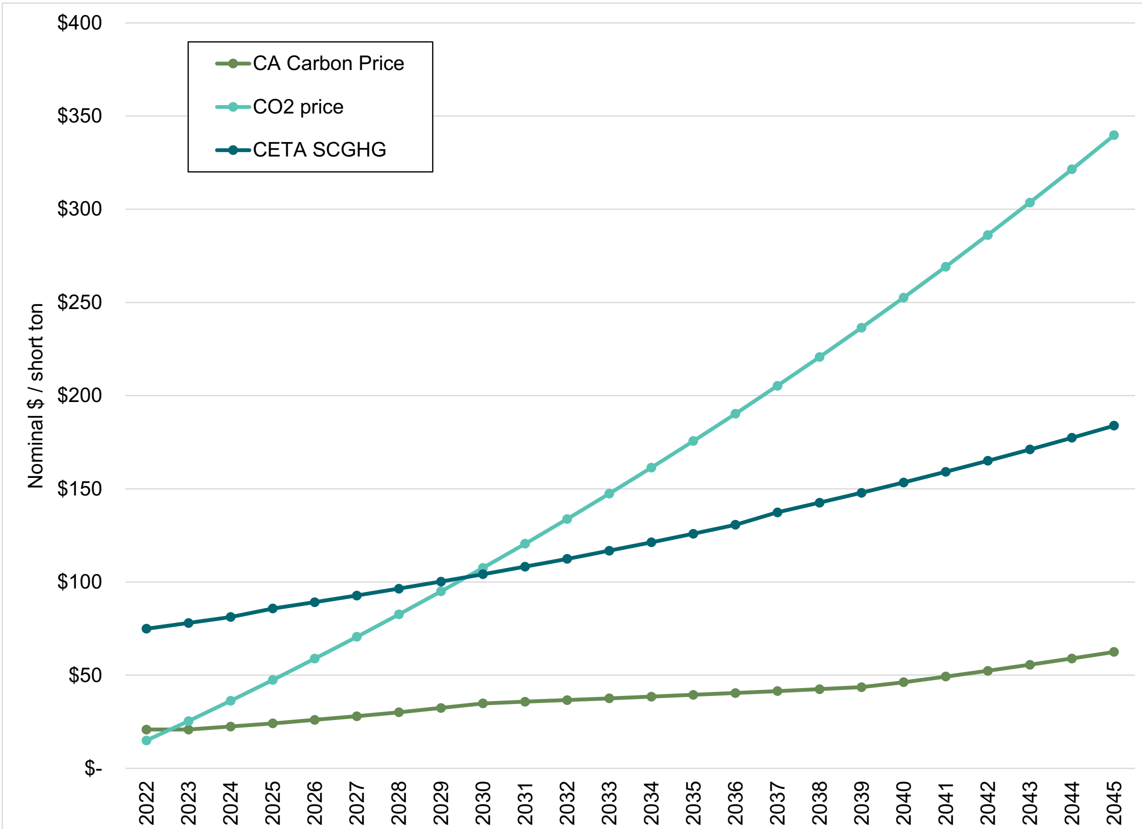
CO_2 Price Inputs

The electric analysis modeled the social cost of greenhouse gases (SCGHG) cited in the Washington Clean Energy Transformation Act (CETA) as a cost adder to thermal resources in Washington state. In addition to the SCGHG mandated by CETA, the analyses modeled the costs imposed by existing CO_2 regulations in California and British Columbia.

SOCIAL COST OF GREENHOUSE GASES (SCGHG). The SCGHG cited in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the *CO_2* prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $189 per ton in 2045,** as shown in Figure 5-7.

CO_2 tax. The CO_2 tax modeled in this IRP is based on HR763 Energy Innovation and Carbon Dividend Act of 2019. The cost starts at $15 per ton and increases at $10 per year, as shown in Figure 5-7.

Figure 5-7: Social Cost of Greenhouse Gases Used in the 2021 IRP



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[12]

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[13] (PSCAA). PSCAA used two models to determine these rates, GHGenius[14] and GREET.[15] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-8: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/mmBtu and then applied to the emission rate of natural gas plants.

12 / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.
13 / Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019
14 / GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/
15 / GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

Renewable Portfolio Standards (RPS) and Clean Energy Standards

Renewable portfolio standards and clean energy standards 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 RCW 19.285). Each state's requirements are applied to the 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 renewable resources are accounted for, they are subtracted from the total WECC RPS need, and the net RPS need is 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 RPS need. Technologies modeled included wind and solar.

WASHINGTON CLEAN ENERGY TRANSFORMATION ACT (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. For the 2021 IRP, PSE reviewed the Washington Department of Commerce fuel mix report. For utilities that are currently more than 80 percent hydro, it was assumed that they will reach 100 percent by 2030 and for utilities that are less than 80 percent hydro, it was assumed they will reach 80 percent by 2030. This broke down to 52 percent of sales in Washington met by utilities that will reach 100 percent by 2030 and 48 percent of sales in Washington from utilities that will reach 80 percent by 2030. This averaged to the assumption that 90 percent of sales in Washington will be met by renewable resources by 2030.

Figure 5-9: RPS Assumptions Modeled for Each State in the 2021 IRP

State	State Legislation	RPS/Clean Energy Standards modeled in 2021 IRP
Arizona	Ariz. Admin. Code §14-2-1801 et seq.	15% by 2025
California	SB 100	2024: 44% of retail sales must be renewable or carbon-free electricity 2027: 52% of retail sales must be renewable or carbon-free electricity 2030: 60% of retail sales must be renewable or carbon-free electricity 2045: 100% of retail sales must be renewable or carbon-free electricity
Colorado	SB 263	2020: 30% of its retail electricity sales must be clean energy resources. 2050: for utilities serving 500,000 or more customers, 100% clean energy sources by 2050, so long as it is technically and economically feasible and in the public interest.
Idaho	None	N/A
Montana	SB 164	15% by 2015
Nevada	SB 358	22% for calendar year 2020 24% for calendar year 2021 29% for calendar years 2022 and 2023 34% for calendar years 2024 – 2026 42% for calendar years 2027 – 2029 50% for calendar year 2030 and every year thereafter (must generate, acquire or save electricity from renewable energy systems) GOAL (not an RPS standard): 100% zero carbon dioxide emission resources by 2050.
New Mexico	SB 489	40% renewable resources by Jan 1, 2025 50% renewable resources by Jan 1, 2030 80% renewable resources by Jan 1, 2040 100% zero carbon resources by Jan 1 2045
Oregon	SB 1547	Large investor-owned utilities: 50% by 2040 Large consumer-owned utilities: 25% by 2025 Small utilities: 10% by 2025 Smallest utilities: 5% by 2025
Utah	SB 202	20% by 2025 (GOAL)
Washington	SB 5116	100% of sales to be greenhouse neutral by 2030 – 80% must be met by non-emitting/renewable resources State Policy: 100% of sales met by non-emitting/renewable resources by 2045
Wyoming	None	N/A

The electric portfolio model assumes that PSE will meet the requirement of 80 percent of sales by 2030 and 100 percent of sales by 2045. Starting with PSE's 40 percent in 2020, the model assumes a linear trajectory to 80 percent by 2030 and then another linear incline to 100 percent by 2045.

Power Price Inputs

To complete the scenarios and prepare them for portfolio modeling, PSE must create wholesale power prices for each scenario, because the different sets of economic assumptions create different future power market conditions. In this context, "power price" does not mean the rate charged to customers, it means the price to PSE of purchasing (or selling) one megawatt (MW) of power on the wholesale market, given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the four scenarios. (AURORA is an hourly chronological price forecasting model based on market fundamentals.) The AURORA database starts with inputs and assumptions from the Energy Exemplar 2018 v1 database. PSE then includes updates such as regional demand, natural gas prices, gas pipeline adders, variable operations and maintenance, CO_2 prices, RPS need, and resource retirements and builds. Figure 5-10 shows the four power prices produced by the four scenario conditions.

> > > See Appendix G, Electric Analysis Models, *for a detailed description of the methodology used to develop wholesale power prices.*

>>> See Appendix H, Electric Analysis Inputs and Results, *for the results of the AURORA capacity expansion run.*

Figure 5-10: Input Power Prices by Scenario,
Annual Average Flat Mid-C Power Price (nominal $/MWh)

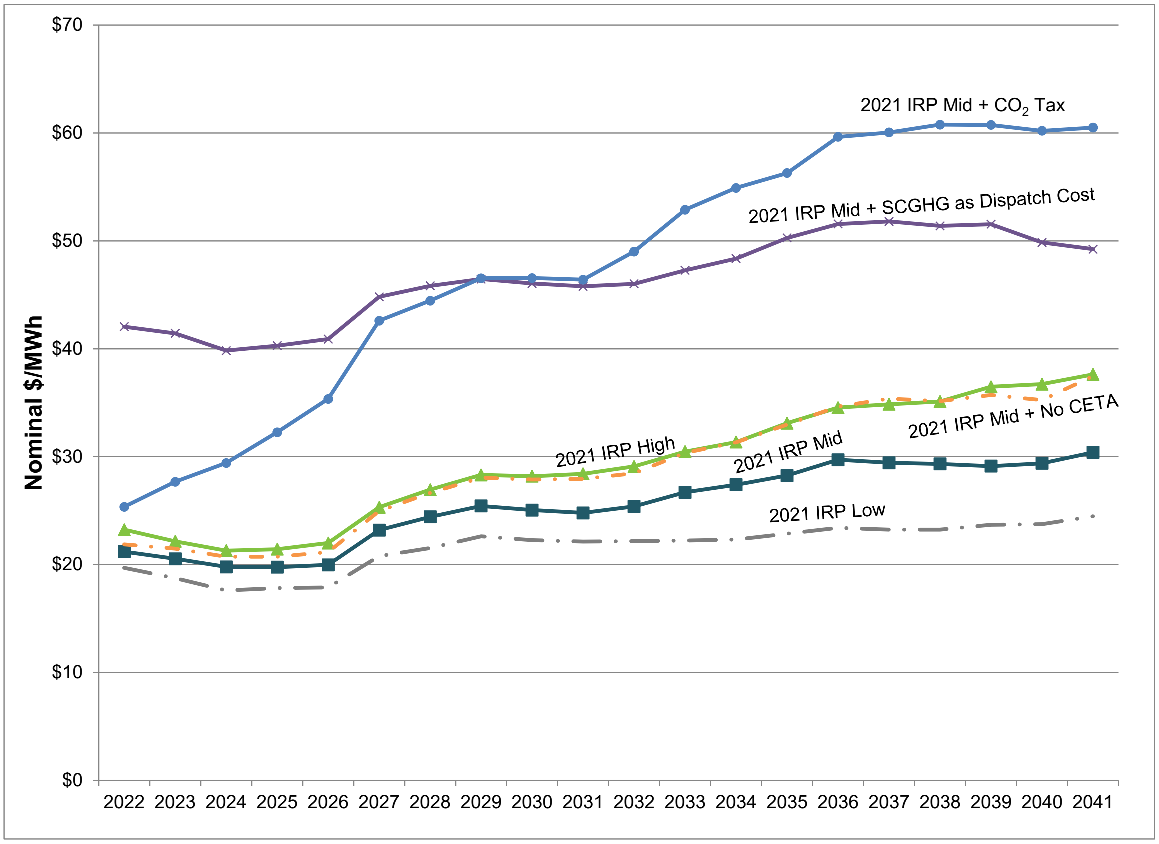
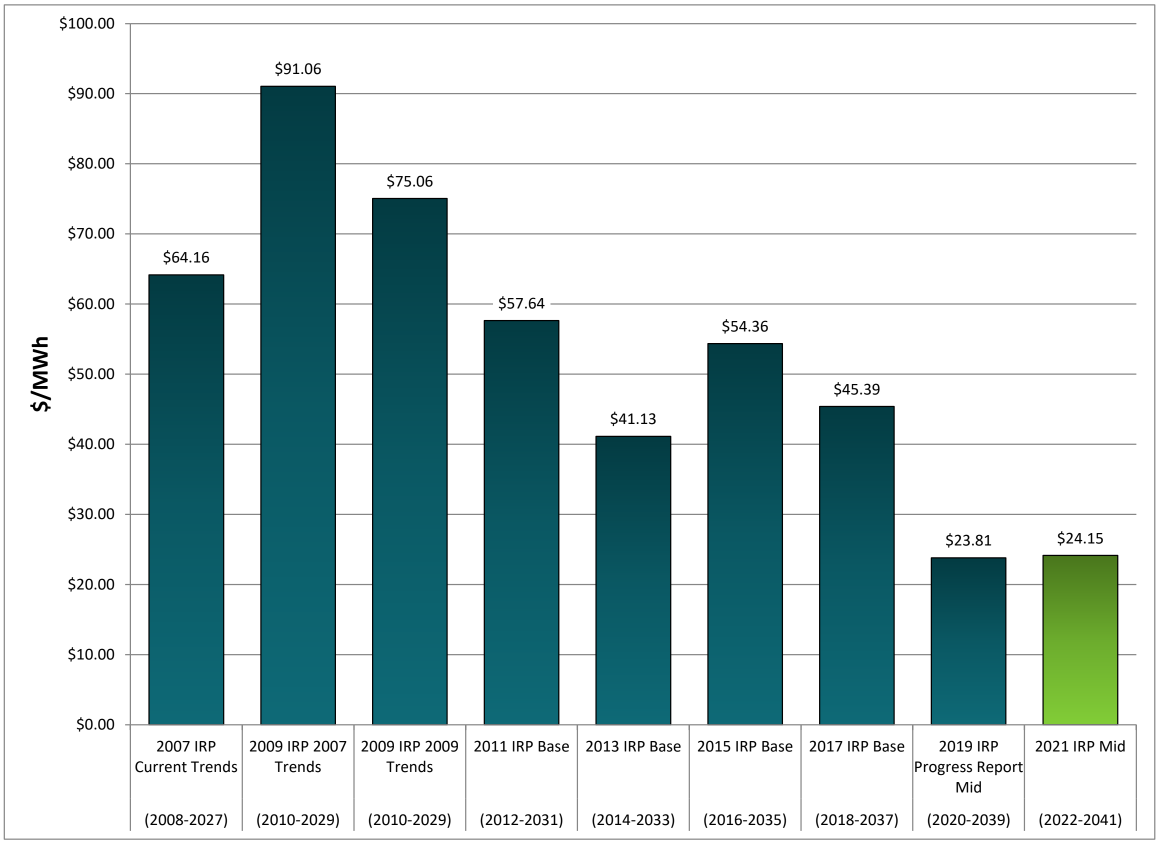


Figure 5-11 below compares the 2021 Mid Scenario power prices to past IRP power prices. In previous IRPs, the downward revisions in forecast power prices corresponded to the downward revisions in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations is driving much of the downward revision in forecasted power prices. The 2015 and 2017 IRP Base Scenarios included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions.

Figure 5-11: 2021 Levelized Power Prices Compared to Past IRPs ($/MWh)



Electric Portfolio Modeling Assumptions

For portfolio modeling, the following assumptions are applied to all scenarios.

Electric Resource Assumptions

PSE modeled the following generic resources as potential portfolio additions in this IRP analysis.

*> > > **See Appendix D, Electric Resources and Alternatives,** for detailed descriptions of the supply-side resources listed here.*
*> > > **See Appendix E, Conservation Potential Assessment and Demand Response Assessment,** for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. These are a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. They 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 drive down energy consumption through government regulation. (Codes and standards impact the demand forecast but have no direct cost to utilities.) Energy efficiency also includes some small-scale electric distributed generation such as combined heat and power.

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

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 can reduce energy loss by eliminating total current flow losses.

Distributed energy resources included the following.

DEMAND RESPONSE. Demand response resources are like energy efficiency in that they reduce customer peak 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.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop or ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-12. Solar data was obtained from the National Solar Radiation Database[16] and processed with the NREL System Advisory Model.[17]

Figure 5-12: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington Residential - rooftop	residential-scale, fixed-tilt, rooftop	15.7
Western Washington Residential - ground	residential-scale, fixed-tilt, ground	16.0

BATTERY ENERGY STORAGE. Two battery storage technology systems were 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 and 4-hour lithium-ion batteries, as well as, 4-hour and 6-hour flow battery systems.

NON-WIRES ALTERNATIVES. The role of distributed energy resources (DER) in meeting system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs and can be deployed across both the transmission and distribution systems, providing some flexibility with how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

16 / https://nsrdb.nrel.gov/
17 / https://sam.nrel.gov/

Supply-side resources included the following.

WIND. Wind was modeled in seven locations throughout the northwest United States including: eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and offshore Washington. A summary of capacity factors for each wind resources are provided below in Figure 5-13. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL) Wind Toolkit Database[18] and processed using an in-house, heuristic wind production model.

Figure 5-13: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
Eastern Washington	36.7
Central Montana	39.8
Eastern Montana	44.3
Idaho	33.0
Eastern Wyoming	47.9
Western Wyoming	39.2
Offshore Washington	34.8

SOLAR. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-14. Solar data was obtained from the National Solar Radiation Database[19] and processed with the NREL System Advisory Model.[20]

18 / *https://www.nrel.gov/grid/wind-toolkit.html*
19 / *https://nsrdb.nrel.gov/*
20 / *https://sam.nrel.gov/*

Figure 5-14: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Eastern Washington	utility-scale, single-axis tracker	24.2
Western Washington	utility-scale, single-axis tracker	16.0
Idaho	utility-scale, single-axis tracker	26.4
Eastern Wyoming	utility-scale, single-axis tracker	27.3
Western Wyoming	utility-scale, single-axis tracker	28.0

PUMPED HYDRO ENERGY STORAGE. 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 at 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. PSE analyzed an 8-hour pumped hydro resource.

HYBRID RESOURCES. In addition to stand-alone generation and energy storage resources PSE modeled hybrid resources which combine two or more resources together at the same location to take advantage of synergies between the resources. PSE model three types of hybrid resource including: eastern Washington solar + 2-hour Lithium-ion battery, eastern Washington wind + 2-hour Lithium-ion battery, and Montana wind + pumped hydro.

BASELOAD THERMAL PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTs). F-type, 1x1 engines with wet cooling towers are assumed to generate 348 MW plus 19 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 OR SCCTs). F-type, wet-cooled turbines are assumed to generate 237 MW and to be located in PSE's service territory. These resources are modeled with either natural gas or an alternative fuel as the fuel source.

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. Unlike baseload resources, they are not intended to operate economically for long periods of time.*

RECIP PEAKERS (RECIPROCATING ENGINES). This 12-engine design with wet cooling (18.2 MW each) is assumed to generate a total of 219 MW and to be located in PSE's service territory.

Electric Resource Cost Assumptions

Generic resource cost assumptions were generated through review of numerous data sources related to generating resources costs and collaboration with the IRP stakeholder group. The generic resource cost assumption methodology was inspired and informed by the NPCC Generating Resource Advisory Committee's (GRAC) cost assumption process.[21]

In brief, the methodology begins with accumulation of generic resource cost estimations from various organizations and regional IRP estimates. Since cost estimations were acquired from different sources, each cost estimate may include a different set of base assumptions, such as inclusion or exclusion of owner's or interconnection costs. Cost estimates were adjusted to align these assumptions as closely as possible. Cost estimates were then arranged by technology vintage year and summary statistics including average, median, minimum and maximum cost were calculated for each vintage year. All cost estimations and statistics were presented to the IRP stakeholder group with the recommendation that PSE use the average cost for modeling purposes. Stakeholder feedback, such as inclusion of new data sources and removal of specific data sources, was incorporated into final generic resource cost assumptions. The spreadsheet used for calculation of generic resource cost assumptions is

21 / *https://www.nwcouncil.org/energy/energy-advisory-committees/generating-resources-advisory-committee*

available for review on the PSE IRP website.[22] This spreadsheet includes a full list of the data sources used for cost estimate purposes and a breakdown of cost estimations by generic resource type.

***> > > See Appendix D, Electric Resources and Alternatives**, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.*

Resource costs are generally expected to decline in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the National Renewable Energy Laboratory (NREL) 2019 Annual Technology Baseline (ATB).[23] The 2020 ATB was delayed due to the pandemic and was not available till after the generic resource costs for this IRP were finalized. The NREL ATB provides three cost curves for each resource, labeled as: Low, Mid and Constant Technology Cost Scenarios. PSE has selected the Mid Technology Cost Scenario for the IRP cost curves as it represents the "most-likely" future cost projection.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes engineering, procurement and construction, owner's costs, and interconnection costs. Interconnection costs include, as needed, natural gas pipelines and 5 miles of transmission from the substation to the main line. The costs calculated using the methodology described above resulted in "overnight capital costs" which typically exclude allowance for funds used during construction (AFUDC) and interconnection costs. PSE has assumed AFUDC costs at 10 percent of the overnight capital cost. PSE derived interconnection costs from a 2018 study on Generic Resource Costs for Integrated Resource Planning[24] prepared by consultant HDR for PSE. PSE believes the estimates used here are appropriate and reasonable.

- Figure 5-15 summarizes generic resource assumptions.
- Figure 5-16 summarizes annual capital cost by vintage year (the year the plant was built) for supply-side resources and energy storage.

22 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx

23 / https://atb.nrel.gov/electricity/2019/index.html?t=lw

24 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Figure 5-15: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First year available	Fixed O&M ($/kw-yr)	Variable O&M[1] ($/MWh)	Capital Costs, Vintage 2021 ($/kw)			
					Overnight Capital Cost	AFUDC[2]	Intercon-nection[3]	Total
CCCT	348	2025	12.87	3.32	1041	104	100	1246
Frame Peaker	237	2025	7.68	7.86	733	73	148	954
Recip Peaker	219	2025	6.40	7.05	1387	139	158	1683
WA Solar - Utility Scale	100	2024	22.23	0.00	1395	139	110	1644
Idaho/Wyoming Solar – Utility Scale	400	2026	22.23	0.00	1395	139	110	1644
WA Solar - Residential Scale	300	2024	0.00	0.00	3264	326	0	3590
Washington Wind	100	2024	40.60	0.00	1569	157	52	1778
Montana Wind	200	2024	40.60	0.00	1569	157	49	1774
Idaho/Wyoming Wind	400	2026	40.60	0.00	1569	157	49	1774
Offshore Wind	100	2030	110.08	0.00	4831	483	71	5385
Pumped Storage	25	2028	16.00	0.00	2367	237	52	2656
Battery 2hr Li-Ion	25	2023	23.49	0.00	937	94	63	1093
Battery 4hr Li-Ion	25	2023	31.93	0.00	1702	170	63	1934
Battery 4hr Flow	25	2023	21.76	0.00	2264	226	63	2553
Battery 6hr Flow	25	2023	37.97	0.00	3157	316	63	3535
Solar + battery	100 solar + 25 battery	2024	45.72	0.00	2099	210	155	2464
Wind + battery	100 wind + 25 battery	2024	64.09	0.00	2255	225	103	2584
Wind + pumped hydro	200 wind + 100 PHES	2028	56.60	0.00	3542	354	91	3988
Biomass	15	2024	207.00	6.20	5791	579	670	7040

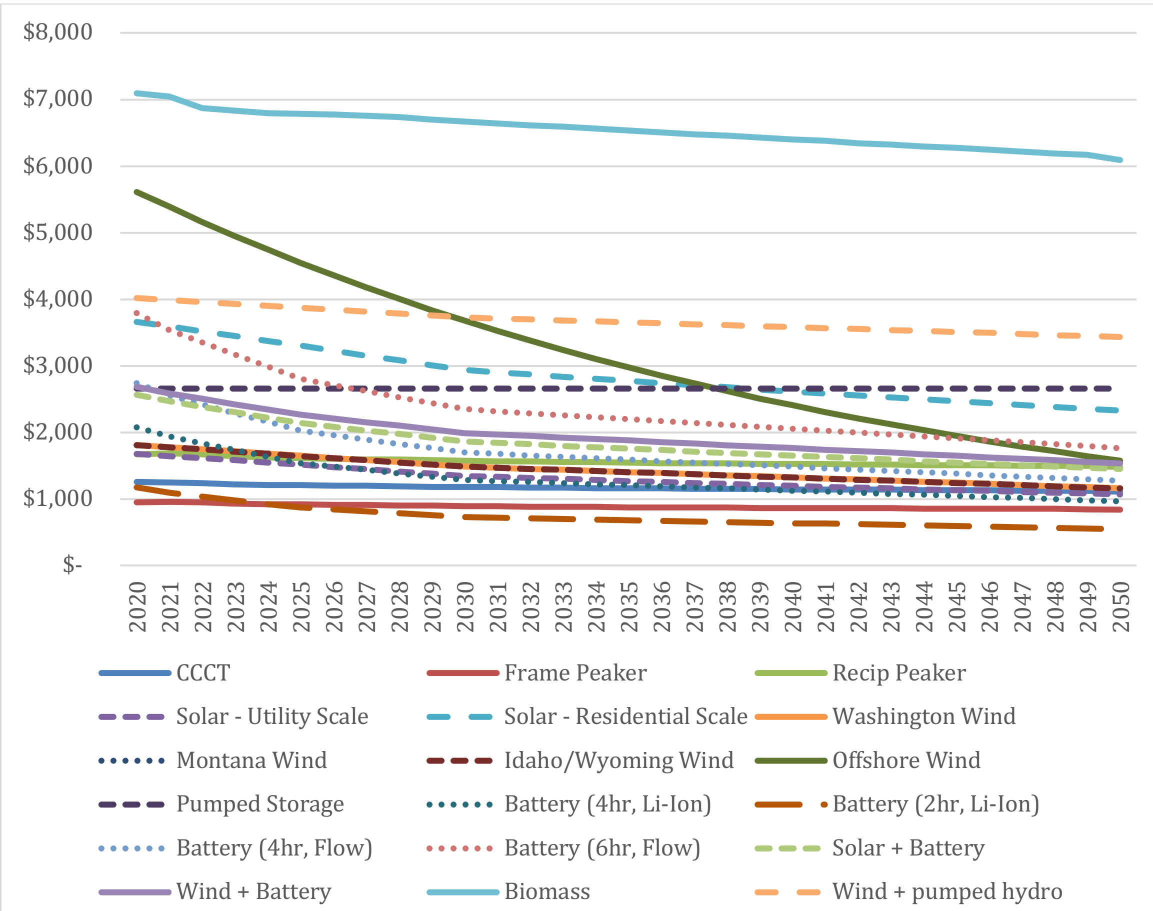
NOTES

1. *Variable O&M costs do not include the cost of fuel for thermal resources*
2. *AFUDC (Allowance for funds used during construction) is assumed at 10 percent of overnight capital*
3. *Interconnection costs includes the transmission, substation and natural gas pipeline infrastructure. Interconnection cost of offshore wind only includes onshore interconnection and does not include the cost of the marine cable to shore.*

The change in capital cost by vintage year is based on the NREL 2019 ATB Mid Technology Cost Scenario. These costs are decreasing on a real basis, but we add a 2.5 percent annual inflation rate for nominal costs. Figure 5-16 shows the annual capital cost of the resources modeled in this IRP by year built in 2020 real dollars.

> > > See Appendix D, Electric Resources and Alternatives, for cost curve charts broken out by resource type (renewable, energy storage and thermal).

Figure 5-16: Annual Capital Costs by Vintage Year (2020 real dollars)



Flexibility Considerations

This analysis focuses on the cost of balancing changes when different resources are added to PSE's portfolio.

The flexibility analysis focused on reflecting the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, different resources can impact costs and how the entire portfolio operates. For example, batteries could avoid dispatch of thermal plants for some ramping up and down.

For the sub-hourly flexibility analysis, PSE used a model called PLEXOS. First a Current Portfolio Case based on PSE's existing resources was created. The Current Portfolio Case begins by creating a simulation that reflects a complete picture of PSE as a BA and PSE's connection to the market. This includes representation of PSE's BAA load and generation on a day-ahead and real time, 15-minute basis. Opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the EIM market in 15-minute increments are also included. For this analysis, PSE simulated the year 2025 for both day-ahead and real time, and then took the difference in total portfolio cost between the two simulations.

PSE tested the impact of a range of potential new resources, each of which is individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the Current Portfolio Case cost, the cost reduction is identified as a benefit of adding the new resource.

Figure 5-17 below is the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.27/kw-yr. This cost savings is applied back to the fixed O&M of the generic resource as a reduction to the cost.

Figure 5-17: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kw-yr)
CCCT	$5.27
Frame Peaker	$23.45
Recip Peaker	$25.39
Lithium-ion battery 2hr	$20.45
Lithium-ion battery 4hr	$18.45
Flow battery 4hr	$23.03
Flow battery 6hr	$23.24
Pumped Storage Hydro 8hr	$18.41
Demand Response	$35.24

> > > See Appendix G, Electric Analysis Models, *for a detailed description of the methodology used to develop flexibility benefit.*

> > > See Appendix H, Electric Analysis Inputs and Results, *for further discussion of heat rate improvements, federal subsidies, financial assumptions such as discount rate and inflation, build constraints, and planned builds and retirements in the WECC.*

Regional Transmission Constraints

Transmission constraints are a set of limits imposed on the IRP portfolio model which seek to model real-world transmission limitations within the WECC. These constraints include capacity limitations, transmission losses and transmission costs.

- Transmission capacity constraints limit the quantity of generation development available to specific geographic regions.
- Transmission losses represent energy lost to heat as power is carried from location to another.
- Transmission costs model the cost of transmission to transmit power from a generating resource to PSE's service territory.

Transmission losses and costs have been a key component of the IRP portfolio model for many IRP cycles. Capacity constraints are a new addition to the modeling process for the 2021 IRP.

Transmission Capacity Constraints

Transmission capacity constraints have become an important modeling consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the goals of CETA. In contrast to thermal resources such as CCCTs and frame peakers, which can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand, renewable resources are site-specific and have variable generation patterns dependent upon local wind or solar conditions, therefore they cannot track load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak demand as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory because a wind farm in one location will produce a different amount of power from the same wind farm located in another location. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory.

ASSUMPTIONS. To model transmission capacity constraints, PSE created seven resource group regions and set limits on the generation capacity which may be built in each of those regions. Resource group regions were determined based on geographic relationships of the generic resources modeled in the 2021 IRP. Figure 5-18 summarizes the resource group regions and the generic resources available in each group.

Figure 5-18: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	Resource Group Region						
	PSE Territory (a)	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	Montana	Idaho / Wyoming
CCCT	X						
Frame Peaker	X						
Recip Peaker	X						
WA Solar East - Utility Scale		X	X		X		
WA Solar West - Utility Scale	X						
Idaho Solar – Utility Scale							X
WY Solar East – Utility Scale							X
WY Solar West – Utility Scale							X
DER WA Solar - Rooftop	X						
DER WA Solar – Ground	X						
WA Wind		X	X		X		
MT Wind – East						X	
MT Wind - Central						X	
ID Wind							X
WY Wind East							X
WY Wind West							X
Offshore Wind				X			
Pumped Storage		X	X		X		
Battery 2hr Li-Ion	X						
Battery 4hr Li-Ion	X						
Battery 4hr Flow	X						
Battery 6hr Flow	X						
Solar + battery		X			X		
Wind + battery		X			X		
Wind + pumped storage						X	
Biomass	X			X			

NOTE
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

Capacity limits were developed based upon PSE's experience with available transmission capability (ATC) on BPA's system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies, regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building and acquisition are complex processes with a variety of possible outcomes, therefore a range of plausible transmission limits and timelines were developed for each region. To provide some structure to these ranges, PSE organized the transmission limits into tiers; uncertainty increases from tier to tier based on the ability of PSE to acquire that quantity of transmission. The tiers include:

- **Tier 1:** Transmission capacity that could likely be acquired in the 2022-2025 timeframe. This transmission capacity draws largely from repurposing PSE's existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that could be acquired in the 2025-2030 timeframe, but is less certain that than Tier 1 transmission projects. This transmission capacity adds new transmission resources to PSE's portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that could be acquired beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from the addition of long lead-time, new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 0:** Tier 0 represents a generally unconstrained transmission system, with the exception of very long distance resources. Tier 0 is used as the baseline transmission case for most of the modeling in the 2021 IRP as these assumptions most closely align with previous IRP cycles. Tiers 1, 2 and 3 are analyzed as sensitivities to gain an understanding of how transmission constraints could impact resource build decisions.

Figure 5-19 summarizes the transmission limits by tier for each resource group region.

Figure 5-19: Transmission Capacity Limitations by Resource Group Region

Resource Group Region	Added Transmission (MW)			
	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

Rationale for each of the transmission capacity limitations by resource group region is provided below.

Eastern Washington: PSE may obtain 150, 300 or 640 MW, for Tiers 1, 2 and 3 respectively, of transmission to the Lower Snake River region through BPA Cluster Study requests. An additional 150, 375 or 690 MW, for Tiers 1, 2 and 3 respectively, of third-party transmission may be acquired from developer submittals and resource retirements.

Central Washington: PSE may obtain 250, 500 or 750 MW, for Tiers 1, 2 and 3 respectively, of transmission by dual-purposing the existing 1,500 MW of Mid-C transmission currently used for market purchases. An additional 125 MW of transmission may be available in Tiers 2 and 3 for delivery of Kittitas area solar via Grant County PUD system.

Western Washington: Assumes no additional transmission available in Tier 1. Tier 2 may add 100 MW of BPA transmission following expiration of the TransAlta PPA in 2025. Tier 3 may add 335 MW of dual-purpose transmission to prioritize renewable generation from the Mint Farm CCCT region. Tier 3 may also add 200 MW of third-party transmission rights from developer submittals and resource retirements.

Southern Washington / Gorge: PSE may obtain 150, 375 or 685 MW, for Tiers 1, 2 and 3 respectively, of third-party transmission rights from developer submittals or resource retirements. Tier 2 may also add 330 MW of dual-purpose transmission to prioritize renewable generation from the Goldendale CCCT region.

Montana: PSE may obtain 350, 565 or 750 MW, for Tiers 1, 2 and 3 respectively, of transmission from repurposing transmission freed up by the removal of Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho: PSE may invest in new transmission projects including the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

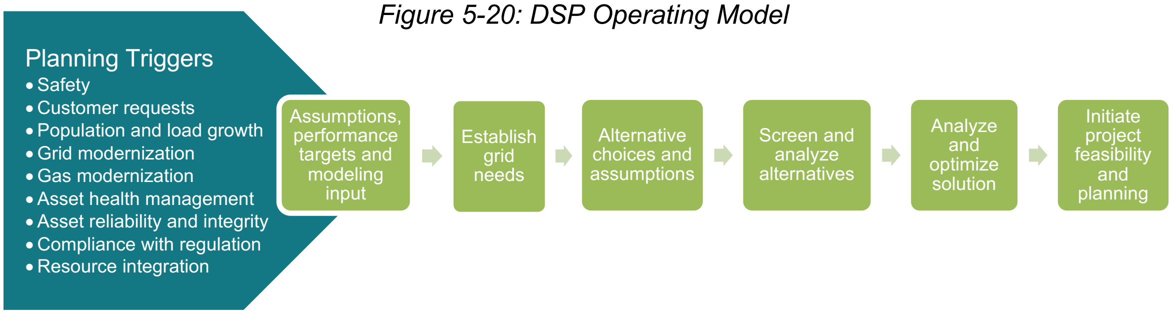
PSE Territory: The assumption for the 2021 IRP is that the PSE system in western Washington is unconstrained, this does not include PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades.

See Appendix M, Delivery System 10-year Plan, for detailed descriptions of transmission and distribution projects planned to ensure unconstrained delivery of resources.

Electric Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs, including effective integration of DERs. The approach and associated planning assumptions are shown in Figure 5-20 below.

Figure 5-20: DSP Operating Model



Assumptions	Description
Demand and Peak Demand Growth	Uses county demand forecast applied based on historic load patterns of substation circuits with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Aging Infrastructure	Known concerns included in analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources	Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements including NESC, NERC and WECC along with addressing voltage regulation, rapid voltage change, thermal limit violations and protection limits

DSP Non-wire Alternatives Forecast

A distributed energy resources forecast is included in the 2021 IRP that evaluates where DERs have been identified as a potential non-wires solution for meeting delivery system needs; the forecast is then extrapolated based on load growth assumptions. As needs arrive in the planning horizon, further analysis relative to specific values and potential will test these assumptions. The non-wires alternatives considered during the delivery system planning process include demand response, targeted energy efficiency, energy storage systems and solar generation, among others, and these resources are considered alone and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions tend to align with needs that are primarily driven by capacity or resiliency. As DER continues to be integrated into system solutions, key questions will need to be answered related to the operational flexibility afforded by DER, as well as related cyber-security considerations. The following assumptions were used to develop a DER forecast for solving identified system needs over the 0 to 10 year time frame.

- Due to practical sizing of DER solutions, projects with needs larger than 20MW were not considered.
- Average historical percentages were applied for determining energy efficiency, demand response and energy storage potential.
- 3 to 4 MW was determined to be a reasonable size for utility-scale PV based on industry knowledge and consultant input for summer needs.

For needs identified in the 10 to 20-year timeframe, the same assumptions were used but the values were extrapolated based on the load forecast (i.e., years with lower forecasted load growth would require fewer, smaller-scale projects to meet system needs versus years with larger forecasted load growth). Additional considerations were made to account for the planning process. Needs identified prior to 2023 are assumed to take 2 to 3 years to complete based on implementation of a new planning process and the learning curve associated with implementing new technologies. As the planning process matures and more experience is gained in siting DER, needs identified after 2023 are assumed to be built by the year that the need first materializes on the system.

Figure 5-21: Forecasted DER Installation by Year and Type

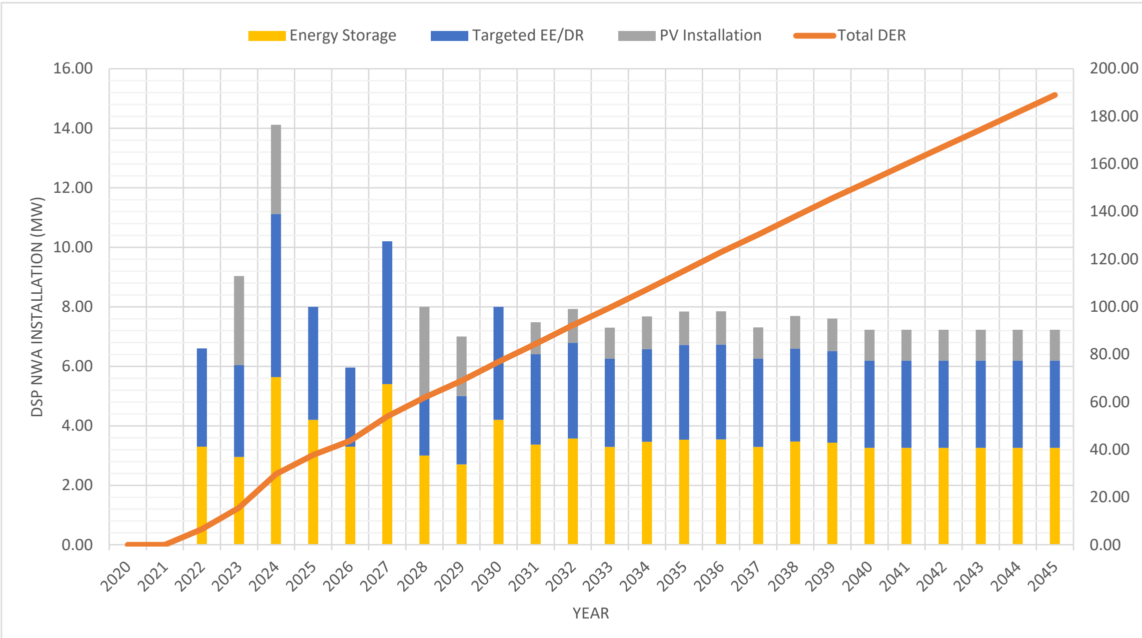


Figure 5-22: Projected T&D Deferral by Project Type by 2040

	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects*	6.6	6.0	0.0	12.6
Planned Substation Capacity Projects	18.1	17.2	6.0	41.3
Future Potential System Needs	60.4	53.7	21.0	135.1
Total	**85.1**	**76.9**	**27.0**	**189.0**

** As identified in the PSE Plan for Attachment K*

Only the energy storage and solar PV forecast was modeled in the IRP as part of the DSP non-wires alternatives. The targeted energy efficiency/demand response forecast is included as part of the cost-effective energy efficiency and demand response evaluation in the IRP.

Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material and voltage impact the magnitude of transmission line losses. BPA assumes a flat 1.9 percent line loss across its entire transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, PSE has assumed a similar loss given the similar distance. Figure 5-23 provides a summary of the transmission lines losses assumed by resource group region.

Figure 5-23: Average Transmission Line Losses by Resource Group Region

Resource Group Region	Line Loss (%)
Eastern Washington	1.9
Central Washington	1.9
Western Washington	1.9
Southern Washington/Gorge	1.9
Montana	4.6
Idaho / Wyoming	4.6

Transmission Cost Constraints

Transmission cost is another factor used in the PSE Portfolio Model to constrain resource build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-yr) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to PSE's service territory. Variable transmission costs are largely composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Figure 5-24 provides a summary of fixed and variable transmission costs by generic resource type.

Figure 5-24: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-yr)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East - Utility Scale	30.48	9.53
WA Solar West - Utility Scale	8.28	9.53
Idaho Solar – Utility Scale	154.78	9.53
WY Solar East – Utility Scale	227.90	9.53
WY Solar West – Utility Scale	207.80	9.53
DER WA Solar - Rooftop	0.00[a]	0.00
DER WA Solar – Ground-mount	0.00[a]	0.00
WA Wind	33.36	9.53
MT Wind – East	49.65	9.53
MT Wind - Central	49.65	9.53
ID Wind	157.66	9.53
WY Wind East	230.78	9.53
WY Wind West	210.68	9.53
Offshore Wind	33.36	9.53
Pumped Storage	22.20	0.00
Battery 2hr Li-Ion	0.00[a]	0.00
Battery 4hr Li-Ion	0.00[a]	0.00
Battery 4hr Flow	0.00[a]	0.00
Battery 6hr Flow	0.00[a]	0.00
Solar + Battery	30.48	9.53
Wind + Battery	33.36	9.53
Wind + Pumped Storage	49.65	9.53
Biomass	22.20	0.00

NOTE
a. Fixed transmission cost is not applied, because the resource is assumed to be built within PSE service territory.

Electric Generation Retirements

For the 2021 IRP, PSE is modeling the economic retirement of existing thermal resources. Colstrip is assumed to be removed from PSE's portfolio by December 31, 2025, but the model is allowed to retire Colstrip earlier based on economics. The other thermal plants are assumed to run through the planning horizon, but they are also allowed to retire early based on economics.

When determining retirement of a generating plant, the model looks at the economics of the power plant for meeting loads and peaks. The valuation process for the generating plants considers the cost of emissions, variable costs (including fuel and operations and maintenance), fixed costs (including ongoing capital for upkeep and maintenance), and decommissioning costs.

Electric Portfolio Sensitivities

Starting with the optimized, least cost Mid Scenario portfolio, sensitivities change a resource, environmental regulation or condition in order to examine the effect of that change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. During the 2021 IRP process, the Resource Planning team identified over 50 potential modeling sensitivities. As part of the 2021 IRP public participation process, the planning team asked stakeholders for assistance in prioritizing which sensitivity analyses to perform. Appendix A, Public Participation, describes the sensitivity prioritization process. Figure 5-25 summarizes the sensitivities modeled in this IRP.

Figure 5-25: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp in over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon free combustion turbines using biodiesel as the fuel.
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus a reduced access to the Mid-C market for sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040(8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources (energy efficiency, distribution efficiency and demand response).
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

A. Renewable Overgeneration Test

In the portfolio model, excess renewable energy that is produced and sold to the Mid-C market is counted towards PSE's CETA renewable goals. In practice, because this energy would not serve PSE loads, it would not count toward meeting CETA goals. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales with respect to renewable overgeneration.

BASELINE ASSUMPTION: PSE can sell excess renewable production to the Mid-C Market.
SENSITIVITY > PSE is not able to sell excess renewable production to the Mid-C Market.

B. Reduced Firm Market Access at Peak Hours

PSE currently uses market purchases of energy in order to meet demand at peak demand hours. As regional emitting resources are retired in response to decarbonization policies and the regional generation supply mix transforms, Mid-C market purchases may not be available to meet peak capacity. This sensitivity reduces the amount of market purchases and sales that can be made, allowing PSE to examine an optimized portfolio that does not rely heavily on market. Determining the behavior of the model under different market circumstances can inform PSE how to navigate a market with reduced peak availability.

BASELINE ASSUMPTION: PSE can purchase and sell up to the Mid-C transmission limit, typically 1500 MW.
SENSITIVITY > The available market at peak is reduced by 200 MW per year down to 500 MW by 2027. The available purchases during the winter months (January, February, November, and December) and the summer months (June, July, and August) are also reduced by 200 MW per year down to 500 MW by 2027.

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

BASELINE ASSUMPTION: PSE's system only has transmission constraints between the PSE system and the Mid-C market.
SENSITIVITY > PSE's system experiences transmission constraints, and the projects available to increase transmission include Tier 1 and Tier 2 transmission projects.

D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines a transmission constraint on the PSE system that is relaxed over time. Transmission will be limited to Tier 1 constraints until 2025, Tier 2 constraints until 2030, Tier 3 constraints until 2035, and unconstrained after 2035. PSE's transmission connection to the Mid-C market remains unchanged in this sensitivity from the Mid Scenario.

BASELINE ASSUMPTION: PSE's system only has transmission constraints between the PSE system and the Mid-C market.
SENSITIVITY > PSE experiences Tier 1 transmission constraints until 2025, Tier 2 constraints until 2030, Tier 3 constraints until 2035, and unconstrained after 2035.

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity explores the acquisition of firm transmission for new resources being less than the total nameplate capacity of the resource. For renewable resources, this may provide a monetary benefit for building less transmission for resources that do not always reach maximum output.

BASELINE ASSUMPTION: New resources are acquired with transmission capable of carrying the full output of the resource.
SENSITIVITY > New resources are obtained with firm transmission that is less than their nameplate capacity.

F. 6-Year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effects of faster adoption rates for conservation.

BASELINE ASSUMPTION: Conservation and demand response measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

G. Non-energy Impacts

This sensitivity adds additional non-energy impacts to the adoption of measures. This increases the amount of energy savings from conservation, assuming there are additional benefits and changes not captured in the data.

BASELINE ASSUMPTION: Conservation measures have the expected load reduction.
SENSITIVITY > Additional conservation measures are cost effective as non-energy impacts reduces the cost of more expensive conservation measures.

H. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

I. SCGHG as an "Externality Cost" (Dispatch Cost) in the Portfolio Model

This sensitivity includes the SCGHG as an externality cost expressed as a variable dispatch cost in the long-term capacity expansion (LTCE) model (only) instead of as a fixed planning adder in order to compare the dispatch methodology to the planning adder methodology. This sensitivity uses the mid electric price forecast with the SCGHG as a separate planning adder to market purchases in the LTCE.

BASELINE ASSUMPTION: The SCGHG is included as a fixed cost of resources in the LTCE Model.
SENSITIVITY > The SCGHG is included as a variable cost of resources in the LTCE model.

J. SCGHG as A Dispatch Cost in Electric Prices and Portfolio Model

This sensitivity includes the SCGHG as a dispatch cost in the LTCE modeling process and in the hourly dispatch and electric price forecast, to compare the dispatch cost methodology with the planning adder methodology. This sensitivity uses a different electric price forecast than in the Mid Scenario portfolio. The SCGHG is added to the electric model as a dispatch cost (tax), so it's included in the electric price forecast. This differs from Sensitivity I in that the electric price with SCGHG is then used in the LTCE instead of the mid electric price plus a planning adder.

BASELINE ASSUMPTION: The SCGHG is included as a fixed cost of resources in the LTCE model only.
SENSITIVITY > The SCGHG is included as a variable cost of resources in the LTCE model and the hourly dispatch model.

K. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology which adds 10,803 g/MMBtu (23 lbs/MMBtu) to the emission rate of natural gas plants.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology which adds 11,564 g/MMBtu (25 lbs/MMBtu) to the emission rate of natural gas plants.

L. SCGHG as a Fixed Cost Plus a Federal CO_2 Cost

This sensitivity includes a Federal CO_2 tax modeled as $15 per short ton with inflation to provide insight into portfolio impacts in the event of a Federal CO_2 tax.

BASELINE ASSUMPTION: The SCGHG is modeled as a planning adder in the LTCE model only.
SENSITIVITY > The SCGHG is modeled as a planning adder in the LTCE model, as well as a $15 per short ton CO_2 tax that is indexed to inflation.

M. Alternative Fuel for Peakers

This sensitivity will model biodiesel as an available fuel option for peaker plants. Results will provide insight into the costs associated with converting the plants to an alternative fuel to meet CETA requirements. Although PSE intended to model hydrogen as an alternative fuel source, PSE did not have sufficient hydrogen pricing at the time of this IRP to perform the analysis.

BASELINE ASSUMPTION: Peaker plants use natural gas as fuel.
SENSITIVITY > Peaker plants use biodiesel as an alternative fuel.

N. 100% Renewable by 2030

This sensitivity forces PSE to adopt 100% renewable resources by 2030, eliminating all natural gas generation to provide context and insight for the push to 100 percent renewable resources by 2045.

BASELINE ASSUMPTION: PSE must reach 100% renewable resources by 2045.
SENSITIVITY > PSE must reach 100% renewable resources by 2030, and all natural gas generation is retired in 2030.

O. 100% Renewable by 2045

This sensitivity forces all natural gas generating plants to be retired by 2045, instead of waiting for economic retirements with CETA penalties. The results will allow PSE to compare the current plans for natural gas plant retirement with CETA penalties.

BASELINE ASSUMPTION: Carbon-emitting resources retire at the end of their economic life.
SENSITIVITY > In 2045, all carbon-emitting resources are retired, regardless of their economic viability.

P. No New Thermal Resources before 2030

This sensitivity does not allow thermal resources to be built before 2030 to allow the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need. Results from this sensitivity will provide insight into how energy storage provides value to the system that has traditionally been provided by natural gas plants.

BASELINE ASSUMPTION: Resources are acquired when they provide the most value to the portfolio.
SENSITIVITY 1 > No new thermal resources are added in the near-term capacity need. The model optimizes to the next lowest cost resource.
SENSITIVITY 2 > Instead of battery storage as the optimal resource, the model uses pumped hydro storage as the resource to meet capacity needs.
SENSITIVITY 3 > The model uses 4-hour lithium-ion battery storage as the resource to meet capacity needs.

Q. Fuel Switching, Gas to Electric

This sensitivity models an increased adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity will illustrate the effects of rapid electrification on the portfolio and demand profile of the PSE service territory.

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory.

R. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: PSE uses the Base Demand Forecast.
SENSITIVITY > PSE uses temperature data from the NPCC. The NPCC is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The NPCC weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the NPCC that is representative of Sea-Tac airport. This data is, therefore, consistent with how PSE plans for its service area, and this data is not mixed with temperatures from Idaho, Oregon or Eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council's climate model.

S. SCGHG Included, No CETA

This sensitivity will model the SCGHG as a fixed cost adder, but not include the CETA renewable requirement. Results from this sensitivity will help to quantify the effect of the SCGHG as a fixed cost adder on the portfolio. Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

BASELINE ASSUMPTION: All CETA requirements, including the SCGHG, are included as modeling constraints.
SENSITIVITY > The SCGHG is included in the modeling process as it is in the Mid Scenario, but all other CETA renewable requirements are removed. The portfolio will meet the RCW 19.285 15 percent renewable target.

T. No CETA

This sensitivity will model the portfolio with no SCGHG as a fixed cost adder and no CETA renewable requirement. Results from this sensitivity will help to quantify the effect of CETA. Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

BASELINE ASSUMPTION: All CETA requirements, including the SCGHG, are included as modeling constraints.
SENSITIVITY > SCGHG and CETA renewable targets removed. Portfolio will meet RCW 19.285 15% renewable target.

U. 2% Cost Threshold

CETA is considered fulfilled once renewable targets are met or once the investments imposed by CETA constraints reach 2 percent of the annual revenue requirement. This sensitivity is included for information only. The Clean Energy Implementation Plan will reconcile competing CETA requirements.

BASELINE ASSUMPTION: The portfolio model must meet CETA renewable energy targets.
SENSITIVITY > CETA requirements are considered met once the portfolio costs reach 2 percent of the annual revenue requirement.

V. Balanced Portfolio

This sensitivity will be performed in order to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources. The inputs for the balanced portfolio were developed using insights gained from analyzing the results of other sensitivity analyses and through the Customer Benefit Indicator framework. The regular electric capacity expansion model is set to optimize total portfolio cost, which delays new builds until near the end of the planning period. This delay produces a lower portfolio cost since the cost curve for all the resources declines over time; however, in reality, it is not always possible to wait until the end years to add a lot of resources. In Sensitivity C, Transmission Build Constraints, the model waits until the last 5 to 10 years to add a significant amount of distributed resources. The balanced portfolio takes those distributed resources and ramps them in over time starting in 2025 and adds more customer programs to meet CETA requirements.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030

W. Balanced Portfolio with Alternative Fuel for Peakers

This sensitivity will be performed in order to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources plus uses biodiesel as a fuel source for new peaking capacity. The inputs for this portfolio were also developed using insights gained from the results of other sensitivity analyses.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time, plus alternative fuel for combustion turbines as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year from the year 2025 to 2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030
- Biodisel used as fuel source for peaking combustion turbines

X. Balanced Portfolio with Reduced Firm Market Access at Peak

This sensitivity is performed to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources plus decreases market reliance to 500 MW by 2027. The inputs for this portfolio were also developed using insights gained from the results of other sensitivity analyses.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030
- The available market at peak is reduced by 200 MW per year down to 500 MW by 2027. The available purchases during the winter months (January, February, November and December) and the summer months (June, July, and Augus)t are also reduced by 200 MW per year down to 500 MW by 2027.

WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivity WX applies the three key changes in Sensitivities V, W and X simultaneously.

Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity WX > Additional DER and customer programs are added to the portfolio as in Sensitivity V; biodiesel is used as a fuel for newly built frame peaker resources as in Sensitivity W; and the portfolio has reduced access to market purchases during peak demand months as in Sensitivity X.

Y. Maximum Customer Benefit

RCW 19.405.040(8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and DR measures are acquired when cost-effective.
SENSITIVITY > Create a portfolio around maximizing different customer benefit indicators.

Z. No DSR

This portfolio looks at the costs and benefits associated with demand-side resources

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > No new energy efficiency and demand response is allowed in the portfolio and all future needs will be met by supply-side resources.

AA. Montana Wind Plus Pumped Hydro Storage

This portfolio evaluates the hybrid resource of wind plus pumped storage hydro.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Instead of adding only Montana wind to the portfolio, the hybrid resource of Montana wind plus pumped hydro storage is added.

3. NATURAL GAS ANALYSIS

Natural Gas Scenarios

Three scenarios were created for the natural gas portfolio analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources.

Figure 5-26: 2021 IRP Natural Gas Analysis Scenarios

2021 IRP NATURAL GAS ANALYSIS SCENARIOS				
	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions

NOTE: 1. Mid demand refers to the 2021 IRP Base Demand Forecast

Scenario 1: Mid

The Mid Scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Scenario 2: Low

This scenario models weaker long-term economic growth than the Mid Scenario. Customer demand is lower in PSE's service territory.

DEMAND

- The 2021 IRP Low Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Scenario 3: High

This scenario models more robust long-term economic growth, which produces higher customer demand.

DEMAND

- The 2021 IRP High Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Natural gas prices are higher as a result of increased demand; the Wood Mackenzie long-term high forecast is applied to natural gas prices.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Natural Gas Scenario Inputs

PSE Customer Demand

The graphs below show the peak demand and annual energy demand forecasts for natural gas service without including the effects of demand side resources (DSR). The forecasts include sales (delivered load) plus system losses. The natural gas peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport.

Figure 5-27: 2021 IRP Natural Gas Sales Peak Day Demand Forecast – Low, Mid, High

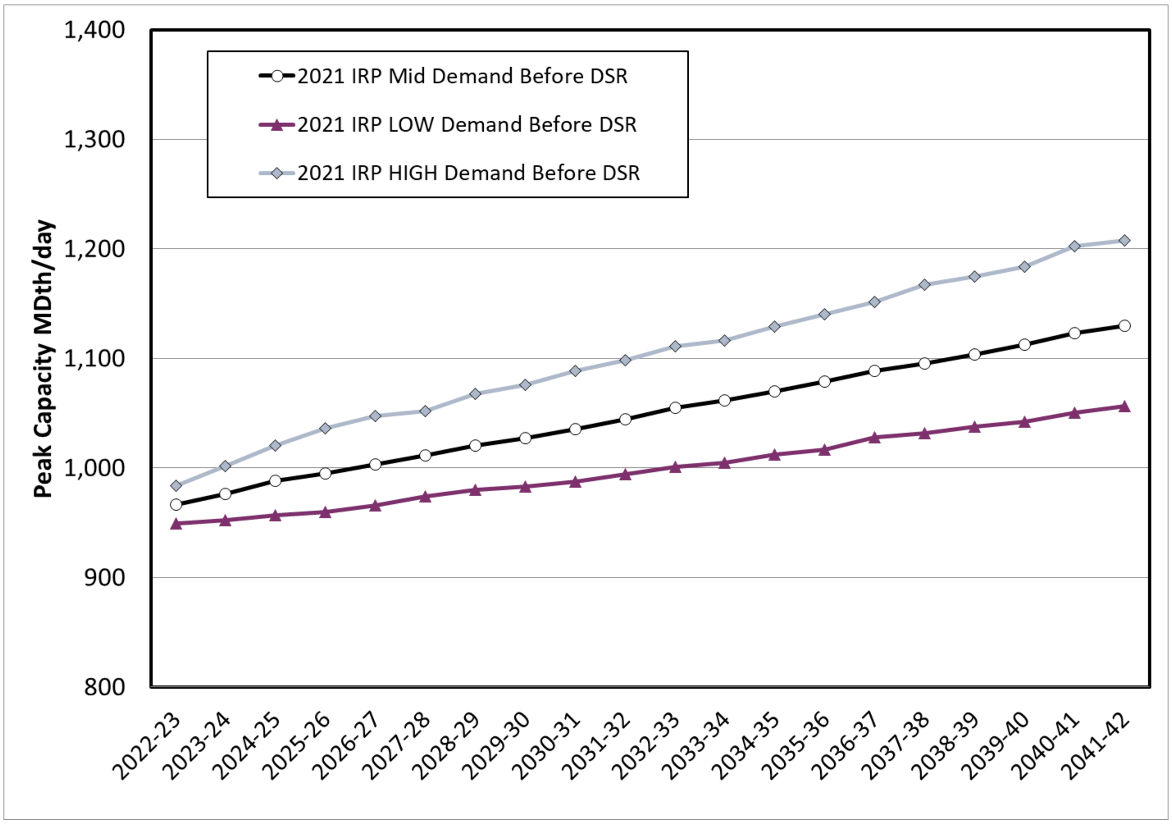
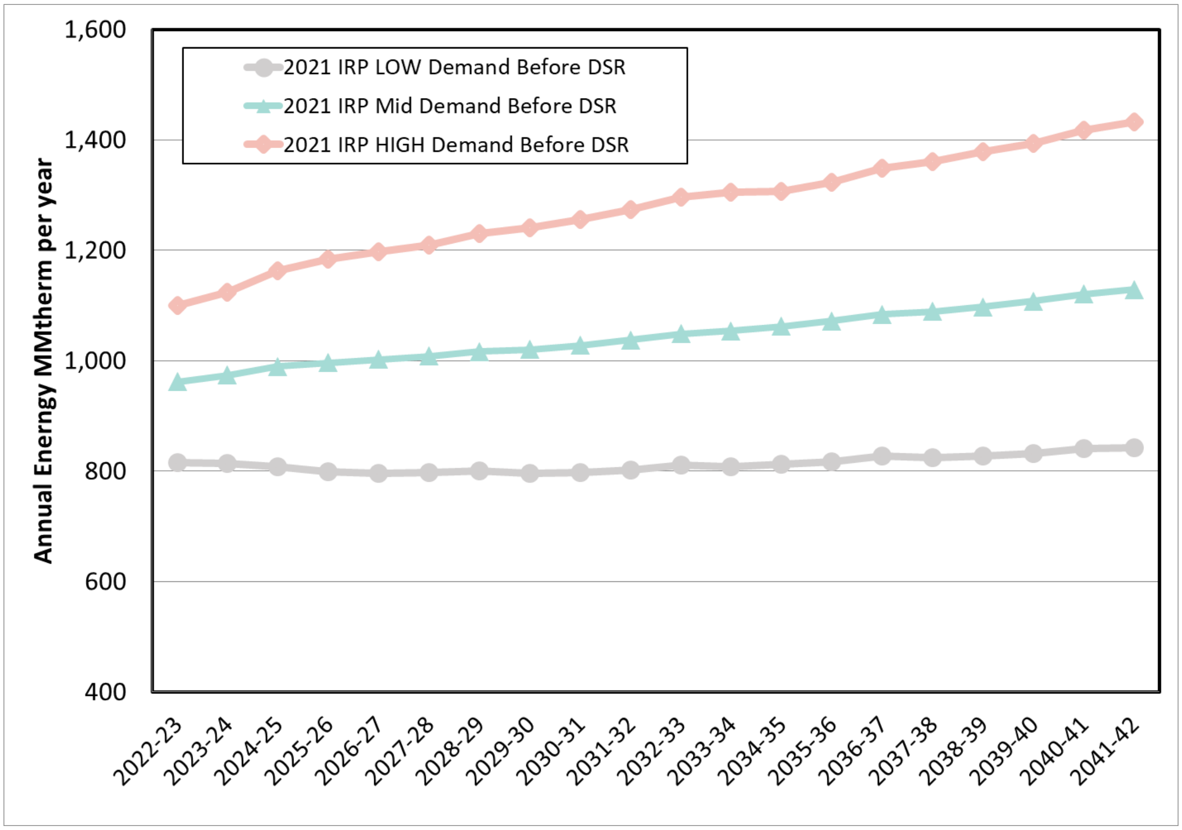


Figure 5-28: 2021 IRP Annual Natural Gas Sales Demand Forecast – Low, Base (Mid), High



Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[25] from Wood Mackenzie.[26]

- From 2022-2026, this IRP uses the three-month average of forward market prices from June 30, 2020. Forward market prices reflect the price of natural gas being purchased at a given point in time for future delivery.
- Beyond 2029, this IRP uses the Wood Mackenzie long-run natural gas price forecast published in July 2020.

25 / The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.
26 / 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 exports.

For the years 2027 and 2028, a combination of forward market prices from 2026 and selected Wood Mackenzie prices from 2029 are used to minimize abrupt shifts when transitioning from one dataset to another.

- In 2027, the monthly price is the sum of two-thirds of the forward market price for that month in 2026 plus one-third of the 2029 Wood Mackenzie price forecast for that month.
- In 2028, the monthly price is the sum of one-third of the forward market price for that month in 2026 plus two-thirds of the 2029 Wood Mackenzie price forecast for that month.

Three natural gas price forecasts are used in the scenario analyses.

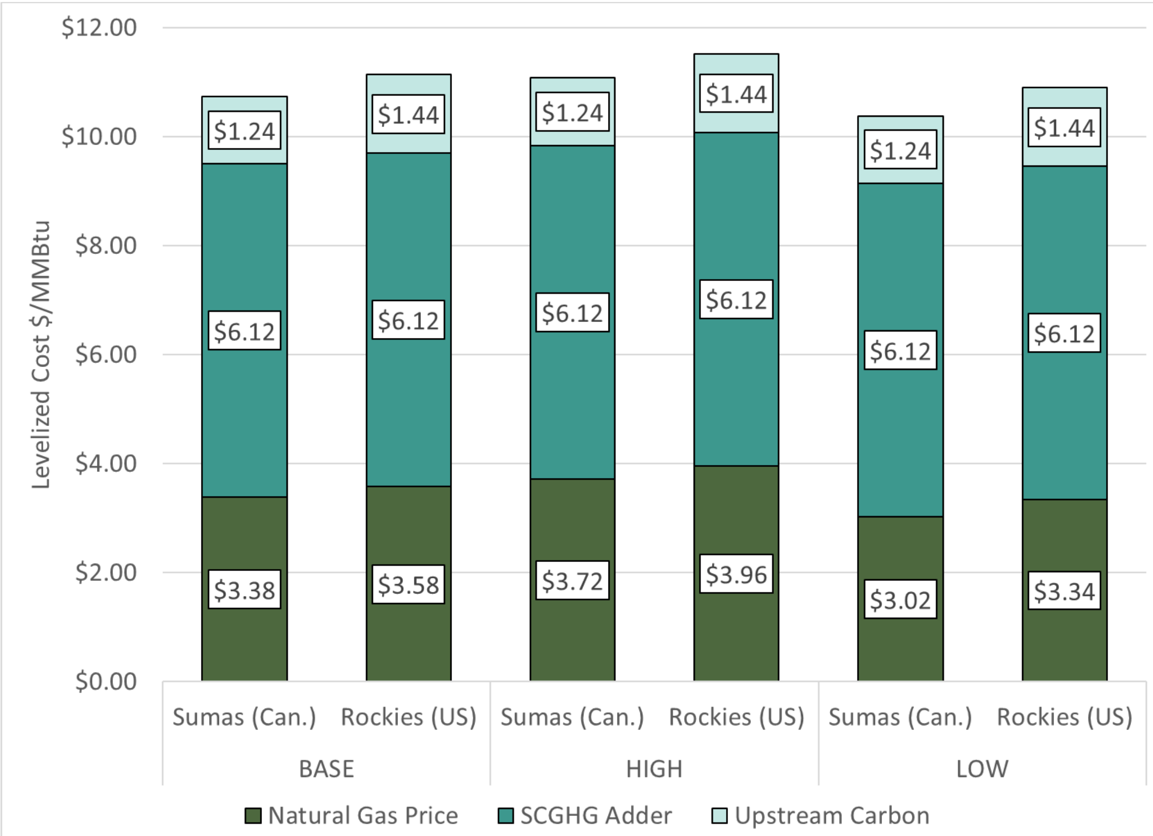
MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie low price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

HIGH NATURAL GAS PRICES. The high natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie high price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

Figure 5-29 below illustrates the range of 20-year levelized natural gas prices used in the 2021 IRP analysis, along with the carbon adders used to develop the total natural gas cost.

Figure 5-29: Levelized Natural Gas Prices and Carbon Adders Used in Scenarios, 2021 IRP

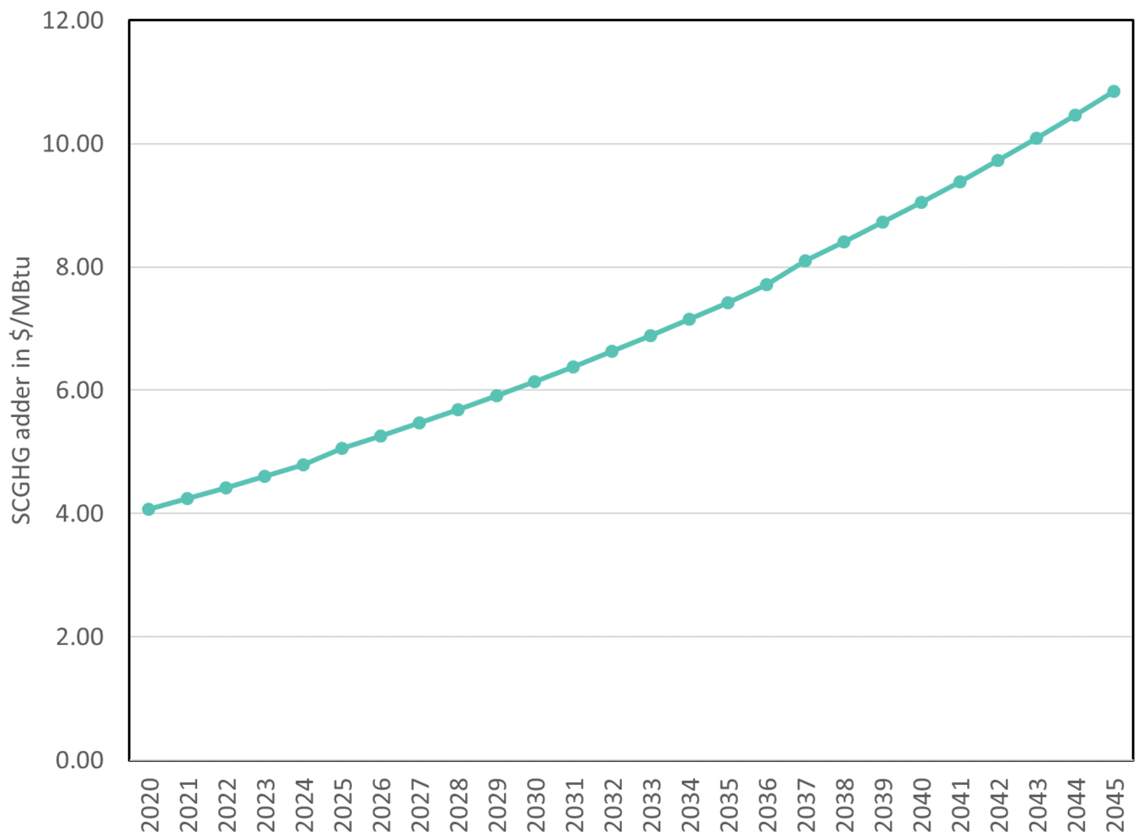


CO_2 Price Inputs

RCW 80.28.380 requires that the natural gas analysis include the cost of greenhouse gases when evaluating the cost-effectiveness of natural gas conservation targets. To implement this requirement, the SCGHG is added to the natural gas commodity price.

SOCIAL COST OF GREENHOUSE GASES. Per RCW 80.28.395, the social cost of greenhouse gases is based on the cost from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the *CO_2* prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $238 per ton in 2052.** This was then converted to a dollars per MMBtu value resulting in Figure 5-31.

Figure 5-30: Social Cost of Greenhouse Gases Used in the 2021 IRP ($/MMBtu)



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[27]

27 / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[28] (PSCAA). PSCAA used two models to determine these rates, GHGenius[29] and GREET.[30] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-31: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

Delivery of Natural Gas within the PSE System

The assumption for the 2021 IRP is that the PSE natural gas delivery system in western Washington is unconstrained. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades. See Appendix M, Delivery System 10-year Plan, for more detailed descriptions of each project.

28 / Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019
29 / GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/
30 / GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

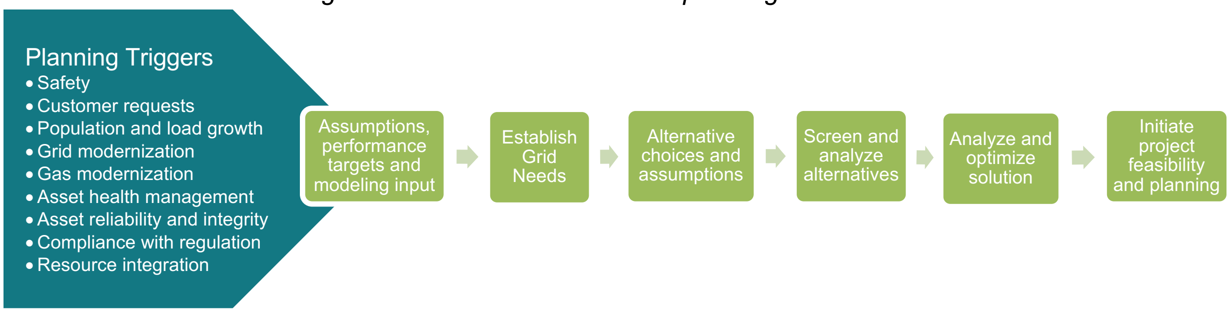
Figure 5-32: Natural Gas Distribution System Planned Work

Transmission and Distribution Summary – Planned work to ensure delivery of resources unconstrained	Description (to be completed for the final IRP)	Project Phase & Estimated In-service date	Potential DER Location
New Intermediate Pressure Main	36 miles	Ongoing	
Gate or Limit Station Upgrades	5	Ongoing	
District Regulation	26	Ongoing	
Gas Main Replaced	200-300 miles	Ongoing	
Bonney Lake Reinforcement (Phase 1)	The project has provided additional capacity and reliability to serve the growth in Bonney Lake area. Phase 1 of the project involved constructing 1.7 miles of 16-inch high pressure main.	36 miles	
Bonney Lake Reinforcement (Phase 2, 3 and 4)	Project driver is to ensure reliability and adequate capacity	5	X
North Lacey Reinforcement	Project driver is to ensure reliability and adequate capacity	26	
Sno-King Reinforcement Projects	Project driver is to ensure reliability and adequate capacity	200-300 miles	
Tolt Pipeline	Project driver is to ensure reliability and adequate capacity	Initiation needed by 2023	

Natural Gas Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs including effective integration of DERs.

Figure 5-33: DSP Natural Gas Operating Model



Assumptions	Description
Peak Hour Demand Growth	Uses county demand forecast applied based on historic load patterns of zip codes with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Pipeline Safety and Aging Infrastructure	Known risk-based concerns included in analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources / Manual intervention	Known controllable devices are included where possible such as compressed natural gas injection at low pressure areas or bypassing valves
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements including Federal PHMSA and pipeline safety WAC codes, such as addressing low pressure concerns or over-pressure events

Natural Gas Alternatives Modeled

Energy efficiency, transportation and storage are key resources for natural gas utilities. PSE modeled the following generic resources as potential portfolio additions in this IRP analysis.

> > > *See* ***Chapter 9, Gas Analysis****, for detailed descriptions of the resources listed here.*
> > > *See* ***Appendix E, Conservation Potential Assessment and Demand Response Assessment****, for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. These are a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. They include three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. (Codes and standards impact the demand forecast but have no direct cost to utilities.)

Supply-side resources included the following.

Transport pipelines that bring natural gas from production areas or market hubs to PSE's service area generally require assembling a number of specific segments and/or natural 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. Seven alternatives were analyzed in this IRP.

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2025, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded Northwest Pipeline (NWP) to PSE's service area. Natural 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 prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2019 to October 2024 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to 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 to begin no earlier than November 2025. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) natural 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. As a major greenfield project, this resource option is dependent on significant additional volume being contracted by other parties.

Combination # 3 – Cross Cascades – NWP from AECO

This option provides for deliveries to PSE via a prospective upgrade of NWP's system from Stanfield, Oregon to contracted points on NWP in the I-5 corridor. Availability is estimated no earlier than November 2025. The increased natural gas supply would come from Alberta (AECO hub) via new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield, Oregon. Final delivery from Stanfield to PSE would be via the upgraded NWP facilities across the Columbia gorge and then northbound to PSE gate stations. Since the majority of this expansion route uses existing pipeline right-of-way, permitting this project would likely be less complicated than for a greenfield project such as the option presented in Combination #2. Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

This option involves PSE leasing storage capacity from NW Natural after an expansion of the Mist storage facility. Pipeline capacity from Mist, located in the Portland area, would be required for delivery of natural gas to PSE's service territory, and the expansion of NWP capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracted by other parties. Mist expansion and a NWP southbound expansion – which would facilitate a lower-cost northbound storage redelivery contract – are not expected to be available until at least November 2025.

Combination # 5 – Plymouth LNG with Firm Delivery

This option includes 70.5 MDth per day firm Plymouth LNG service and 15 MDth per day of firm NWP pipeline capacity from the Plymouth LNG plant to PSE. Currently, PSE's electric power generation portfolio holds this resource, which may be available for renewal for periods beyond April 2023. While this a valuable resource for the power generation portfolio, it may be a better fit in the natural gas sales portfolio.

Combination # 6 – LNG-related Distribution Upgrade

This combination assumes commissioning of the LNG peak-shaving facility, providing 69 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, which would allow an additional 16 MDth per day of vaporized LNG to reach more customers. In effect, this would increase overall delivered supply to PSE customers, since natural gas otherwise destined for the Tacoma system would be displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024/25.

Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility discussed above. The 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, and could be available on three years' notice as early as winter 2024/25.

Natural Gas Resource Build Constraints

Natural gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent "lumpiness" in natural 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: 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.

Natural Gas Portfolio Sensitivities

Figure 5-34: 2021 IRP Natural Gas Portfolio Sensitivities

2019 IRP NATURAL GAS ANALYSIS SENSITIVITIES		
A	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
B	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
C	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
D	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
E	Temperature Sensitivity on Load	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
F	No DSR	This portfolio will not include any new demand-side resources energy efficiency, distribution efficiency and demand response

A. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE uses the AR4 Upstream Emissions calculation methodology which adds 10,803 g/MMBtu to Canadian supply emissions and 12,121 g/MMBtu to US supply emissions.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology which adds 11,564 g/MMBtu to Canadian supply emissions and 13,180 g/MMBtu to US supply emissions.

B. 6-Year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effect of faster adoption rates.

BASELINE ASSUMPTION: Conservation and demand response measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

C. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

D. Fuel Switching, Gas to Electric

This sensitivity models an increased adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity will illustrate the effects of rapid electrification on the portfolio and the demand profile of the PSE service territory.

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory resulting in a lower natural gas demand forecast.

E. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: PSE uses the base demand forecast.

SENSITIVITY > PSE uses temperature data from the NPCC. The NPCC is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The NPCC weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the NPCC that is representative of SeaTac airport. This data is, therefore, consistent with how PSE plans for its service area and this data is not mixed with temperatures from Idaho, Oregon or Eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which the temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council’s climate model.

F. No DSR

This portfolio looks at the benefits associated with demand-side resources

BASELINE ASSUMPTION: New energy efficiency resources are acquired when cost effective and needed.

SENSITIVITY > No new energy efficiency is allowed in the portfolio and all future needs will be met by supply-side resources.

6 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 and in Delivery System Planning (DSP) needs assessments.

6 Demand Forecasts

Contents

1. OVERVIEW

The demand forecasts developed for the IRP estimate the amount of electricity or natural gas that will be required to meet the needs of customers over the 20+ year study period. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand refers to the total amount of electricity or natural gas needed to meet customer needs in a given year.
- Peak demand refers to the amount of electricity or natural gas needed to serve customer need on the coldest day of the year, since PSE is a winter-peaking utility.

NOTE: The terms “demand” and “load” are often used interchangeably, but they actually refer to different concepts. “Demand” refers to the amount of energy needed to meet the needs of customers during a calendar year, including losses. “Load” refers to demand plus the planning margin and operating reserves needed to ensure reliable and safe operation of the electric and natural gas systems.

Overall, electric energy demand before additional conservation in the 2021 IRP Base Demand Forecast is expected to grow at an average annual rate of 1.2 percent during the study period from 2022 to 2045, resulting in an increase from 2,500 aMW in 2022 to 3,316 aMW in 2045. This is slower than the 1.4 average annual energy growth rate forecast during the 2019 IRP Process. Electric peak demand before additional conservation is expected to increase at a 1.2 percent annual growth rate, resulting in an increase from 4,687 MW in 2022 to 6,159 MW in 2045. This is also slower than the 1.3 percent average annual growth rate forecast during the 2019 IRP Process and results in lower total peak demand at the end of the study period. System growth is driven by customer additions. Demand from customers using electric vehicles drives up residential and commercial use per customer in the second half of the study period.

The 2021 IRP Natural Gas Base Demand Forecast before additional conservation for both energy and peak demand is also lower than forecast during the 2019 IRP Process. However, for energy, the average annual growth rate (0.8 percent) is higher compared to the 2019 IRP Process (0.7 percent). For peak demand, the average annual growth rate in the 2021 IRP forecast is the same as that in the 2019 IRP Process (0.8 percent). Lower residential customer counts, lower residential use per customer, lingering COVID-19 effects, and the inclusion of recent data on cold weather days in calculating weather sensitivity reduced demand.

In this IRP, the Base Demand 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 2019. For the 2021 IRP, the natural gas and electric analysis included a temperature sensitivity on demand. PSE proposed three alternative temperature assumptions to stakeholders, and stakeholders selected the temperature assumption with the greatest warming trend. This sensitivity has temperatures warming over time following the trend of one model that the Northwest Power and Conservation Council is using in its climate analyses. More information on this sensitivity can be found in Chapter 5, Key Analytical Assumptions, and the related demand forecast is discussed later in this chapter.

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. For the High and Low Demand Forecasts, historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

CONSERVATION IMPACTS. Demand is reduced significantly when forward projections of additional conservation savings are applied, as shown in Figure 6-1. 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.

NOTE: Throughout this chapter, charts labeled “before additional DSR” include only demand-side resource (DSR) measures implemented before the study period begins in 2022. Charts labeled “after applying DSR” include the cost-effective amount of DSR identified in the 2021 IRP.

Figure 6-1: Effect of Conservation Impacts on Demand Forecasts

2021 IRP Base Forecast at End of Forecast Period	Before Additional DSR	After Applying DSR
Electric Energy Demand (aMW) (2045)	3,316	2,604
Electric Peak Demand (MW) (2045)	6,159	4,966
Natural Gas Energy Demand (Mdth) (2041)	112,918	100,678
Natural Gas Peak Demand (Mdth) (2041)	1,130	1,019

2. ELECTRIC DEMAND FORECAST

Highlights of the IRP Base, High and Low Demand Forecasts developed for the electric service area are presented below in Figures 6-2 through 6-5. The population and employment assumptions for all three forecasts are summarized in the section titled “Details of Electric Forecast” and explained in detail in Appendix F, Demand Forecasting Models.

Only DSR measures implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio.

Electric Energy Demand

In the 2021 IRP Base Demand Forecast, energy demand before additional DSR is expected to grow at an average rate of 1.2 percent annually from 2022 to 2045, increasing energy demand from 2,500 aMW in 2022 to 3,316 aMW in 2045.

Residential and commercial demand are driving the growth in total energy. Excluding losses, these customer classes are projected to represent 50 percent and 38 percent of demand in 2022, respectively. On the residential side, use per customer is expected to be relatively flat for the short term but to grow over time, mainly due to the adoption of electric vehicles. This, plus population growth, is driving residential energy demand. On the commercial side, use per customer is relatively flat as well, with a small amount of growth in the later part of the forecast due to electric vehicle growth. Rising customer counts therefore drive much of the growth.

The 2021 IRP High Demand Forecast projects an average annual growth rate (AARG) of 1.6 percent; the Low Demand Forecast projects 0.9 percent.

Figure 6-2: Electric Energy Demand Forecast before Additional DSR

Base, High and Low Scenarios (aMW)

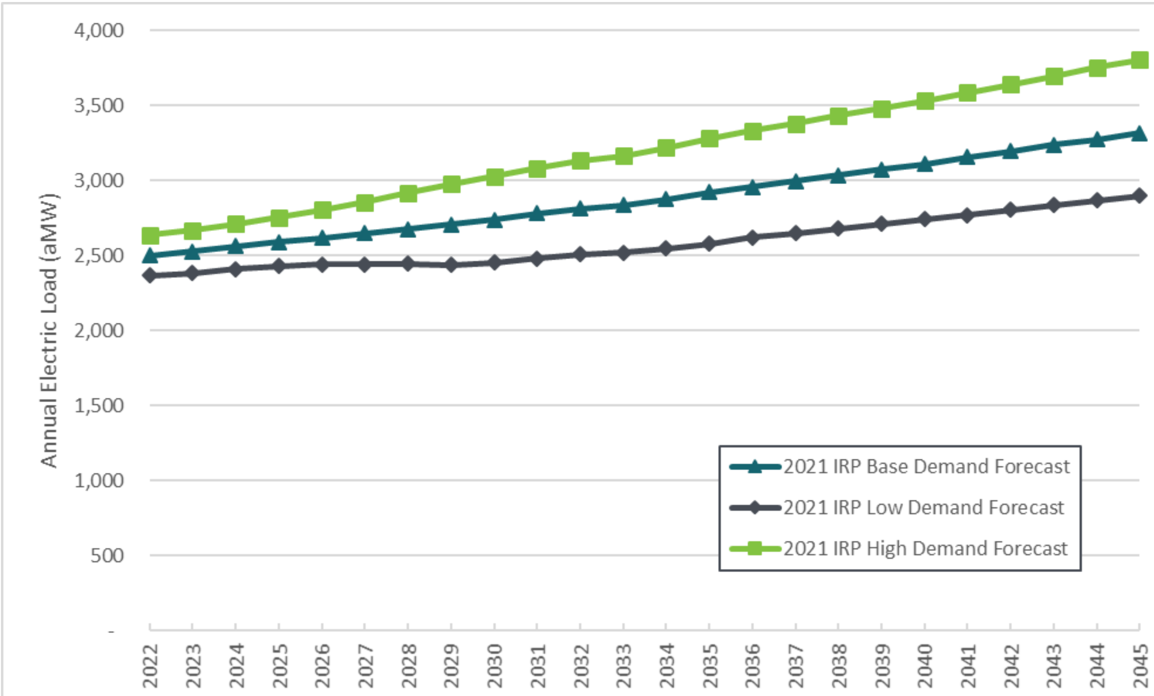


Figure 6-3: Electric Energy Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios

2021 IRP ELECTRIC ENERGY DEMAND FORECAST SCENARIOS (aMW)							
Scenario	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
2021 IRP Base Demand Forecast	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
2021 IRP High Demand Forecast	2,636	2,753	3,029	3,281	3,531	3,803	1.6%
2021 IRP Low Demand Forecast	2,367	2,429	2,454	2,580	2,742	2,897	0.9%

Electric Peak Demand

PSE is a winter peaking utility, meaning that the one hour during the year with the highest demand occurs during the winter. The capacity expansion model analyzes winter peaks. However, summer peaks are growing with warming summer temperatures and increased saturation of air conditioning in the region. Different types of supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, PSE considers demand during all hours of the year in the resource adequacy modeling to help determine the best resources to meet load from our customers. This section describes the winter and summer electric peaks.

Winter Electric Peak Demand

The normal electric winter peak hour demand is modeled using 23 degrees Fahrenheit as the design temperature. Since PSE is a winter peaking utility, this peak has historically occurred in December but is occurring in other winter months as well. The 2021 IRP Base Demand Forecast shows a 1.2 percent average annual growth rate for peak demand; this would increase peak demand from 4,687 MW in 2022 to 6,159 MW in 2045.

The 2021 IRP High Demand Forecast shows an average annual peak demand growth rate of 1.5 percent, and the Low Demand Forecast shows a 0.9 percent average annual growth rate.

Figure 6-4: Winter Electric Peak Demand Forecast before Additional DSR Base, High and Low Scenarios, Hourly Annual Peak (MW)

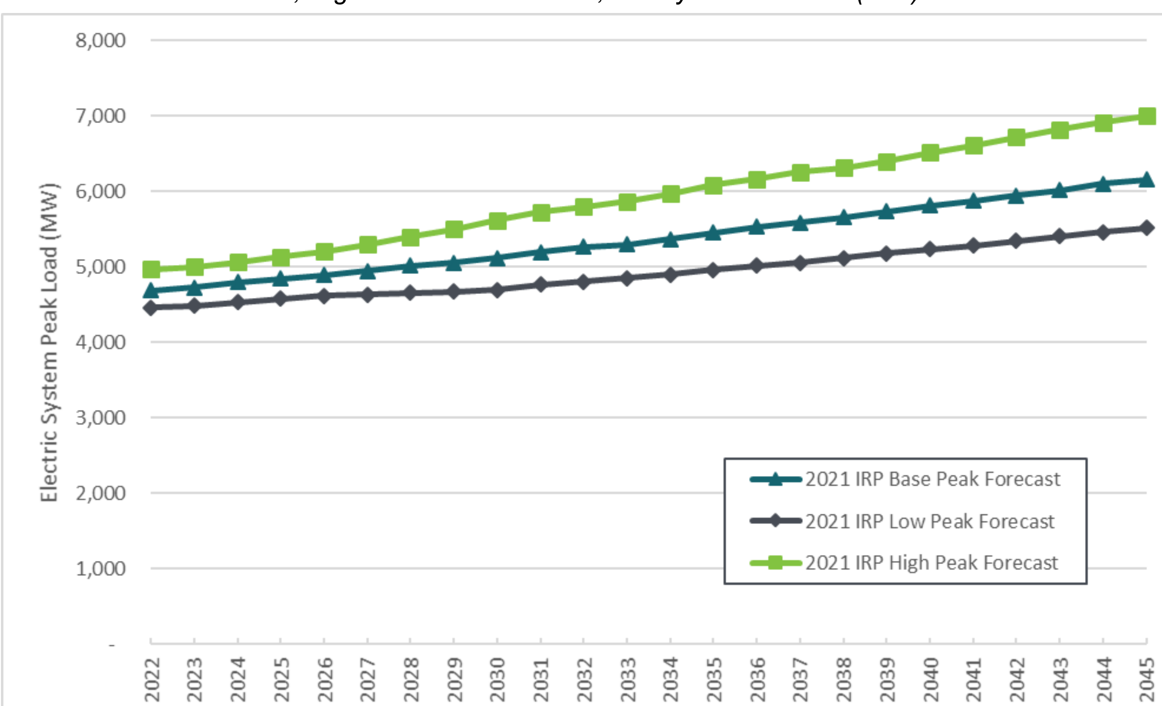
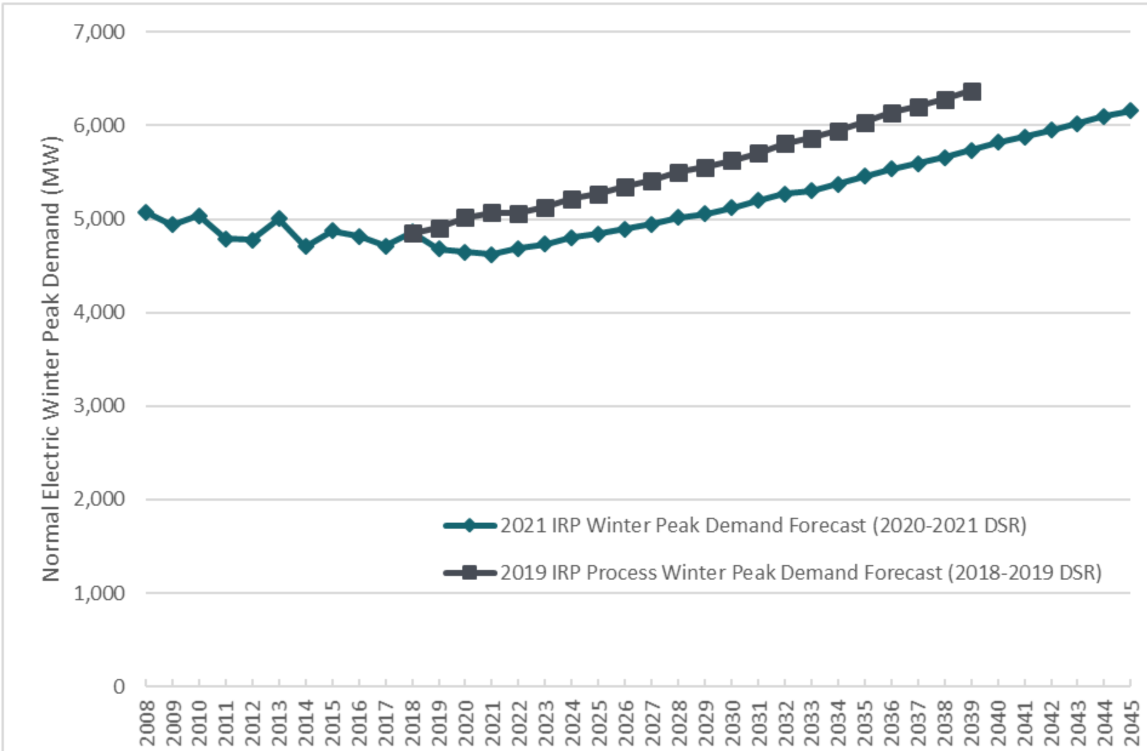


Figure 6-5: Winter Electric Peak Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (MW)

2021 IRP WINTER ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,687	4,844	5,123	5,455	5,819	6,159	1.2%
2021 IRP High Demand Forecast	4,972	5,138	5,622	6,085	6,521	7,001	1.5%
2021 IRP Low Demand Forecast	4,466	4,581	4,697	4,966	5,240	5,519	0.9%

Peak demand in the 2021 IRP Base Demand Forecast is lower at the end of the study period (6,159 MW in 2040) compared to the 2019 IRP Process (6,370 MW in 2039). Additionally, the 2021 IRP Peak Demand Forecast has a slower average annual growth rate (1.2 percent) compared to the 2019 IRP Process (1.3 percent). The 2021 IRP Peak Demand Forecast projects slower growth than the 2019 IRP Process Peak Demand Forecast because the 2021 IRP Demand Forecast grows at a slower rate than the 2019 IRP Process due to slower anticipated customer growth (particularly commercial) and lower projected use per customer in all non-residential classes. Observed actual residential customers and sales growth in 2018 and 2019 offset the non-residential trends; however, the downward growth drivers related to lower commercial usage and COVID-19 result in a lower long-term growth rate.

Figure 6-6: Winter Electric Peak Demand Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Hourly Annual Peak (23 Degrees, MW)



Summer Electric Peak Demand

The normal electric summer peak hour demand is modeled using 93 degrees Fahrenheit as the design temperature. Summer peaks typically occur in July or August. Figure 6-7 shows the 2021 IRP Base Peak Demand Forecast for the winter and the summer. The 2021 IRP Base summer peak demand forecast has an average annual growth rate of 1.7 percent. This increases the summer peak demand from 3,515 MW in 2022 to 5,183 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, it is assumed that PSE will continue to be a winter peaking utility for the planning period of this IRP.

Figure 6-7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR Base Scenario, Hourly Annual Peak (MW)

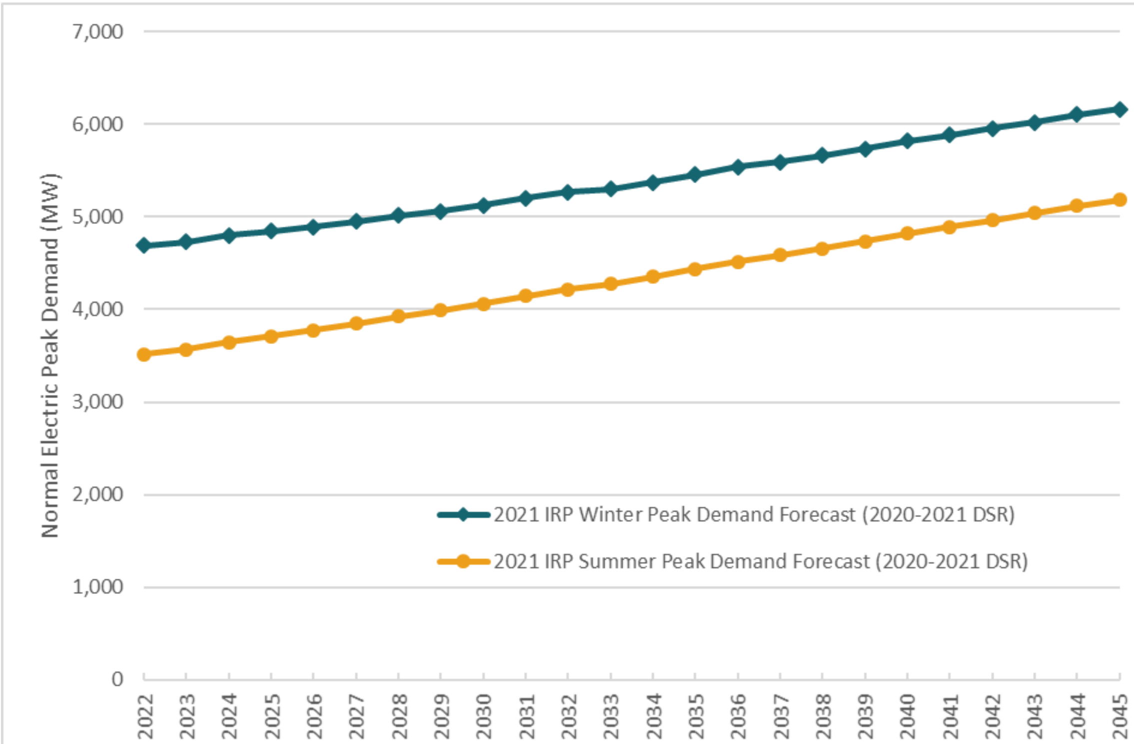


Illustration of Conservation Impacts

The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2020 and 2021, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2022 to 2045.

However, PSE also examines the effects of conservation on the energy and peak demand over the full planning horizon. Forecasts with conservation are used internally at PSE for financial and system planning decisions. To illustrate conservation impacts, the cost-effective demand-side resources identified in this IRP[1] are applied to the Base Scenario energy and peak demand forecasts for 2022 to 2045. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation is also applied for that period. The results are illustrated in Figures 6-8 and 6-9, below.

[1] / *For demand-side resource analysis, see Chapter 8, Electric Analysis, and Appendix E, Conservation Potential Assessment and Demand Response Assessment.*

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied to the energy demand forecast:

- Electric energy demand in 2045 is reduced 21 percent to 2,604 aMW.
- Electric energy demand after DSR grows at an average annual rate of 0.23 percent from 2022 to 2045.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 portfolio analysis are applied to the peak demand forecast:

- Electric system peak demand in 2045 is reduced 19 percent to 4,966 MW.
- Electric system peak demand after DSR grows at an average annual rate of 0.3 percent from 2022 to 2045.

Figure 6-8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Applying DSR

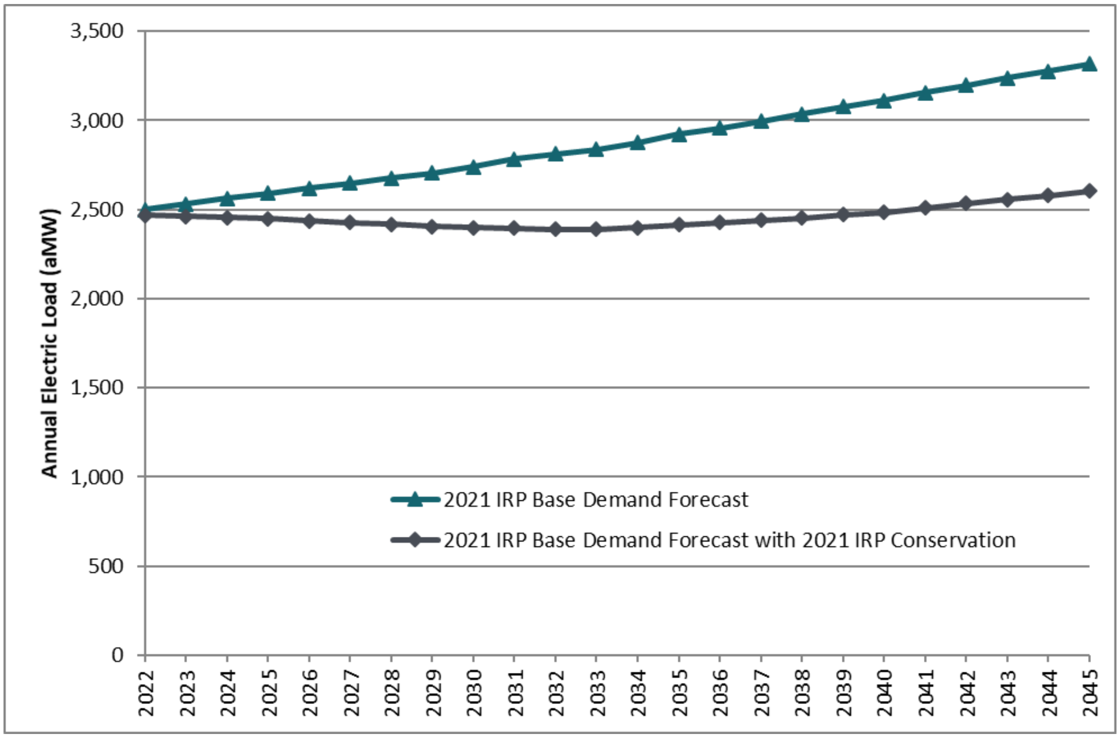
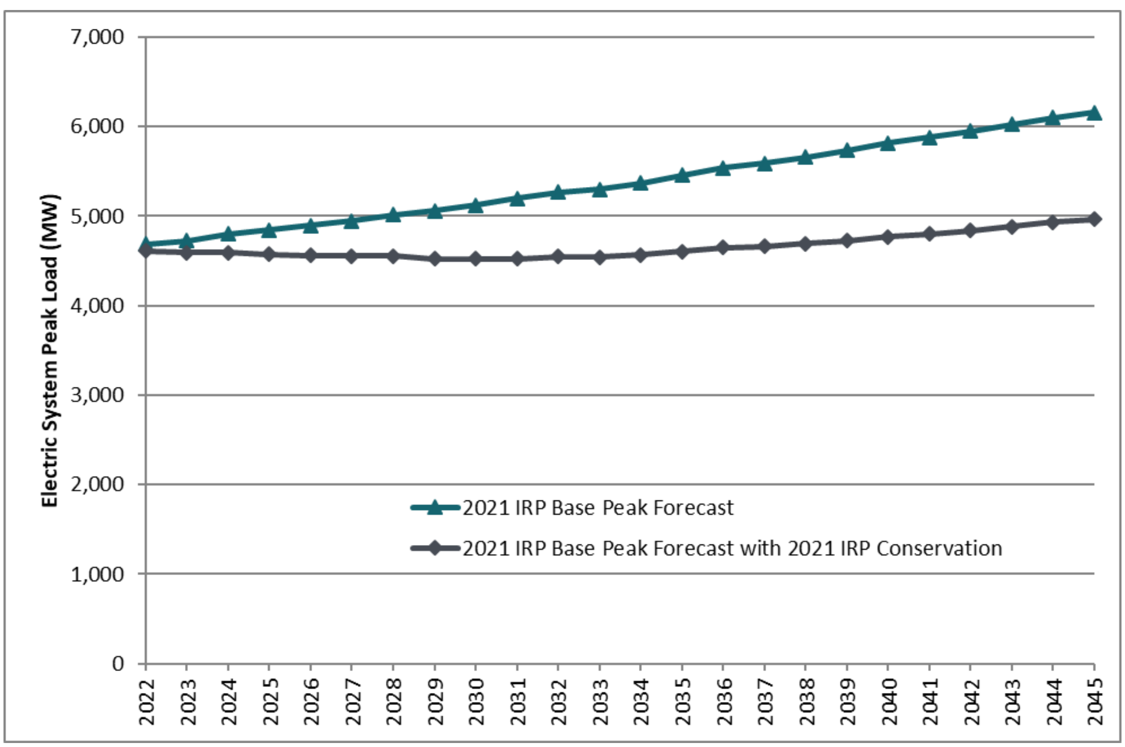


Figure 6-9: Electric Peak Demand Forecast (MW), before Additional DSR and after Applying DSR



Details of Electric Forecast

Electric Customer Counts

System-level customer counts are expected to grow by 1.0 percent per year on average, from 1.21 million customers in 2022 to 1.53 million customers in 2045. This is slower than the average annual growth rate of 1.2 percent projected in the 2019 IRP Process Base Demand Forecast.

Residential customers are driving the overall customer count increase, since they are projected to represent 88 percent of PSE's electric customers in 2022. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2023 to 2045. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.9 percent. Industrial customer counts are expected to decline, following a historical trend. These trends are expected to continue as the economy in PSE's service area shifts toward more commercial and less industrial industries.

Figure 6-10: December Electric Customer Counts by Class, 2021 IRP Base Demand Forecast

2021 IRP DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST							
Class	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Total	1,210,701	1,253,182	1,324,465	1,395,434	1,463,388	1,529,051	1.0%
Residential	1,066,293	1,103,799	1,167,538	1,230,936	1,291,536	1,349,980	1.0%
Commercial	133,023	137,547	144,357	151,236	157,975	164,647	0.9%
Industrial	3,249	3,193	3,106	3,023	2,948	2,882	-0.5%
Other	8,130	8,643	9,464	10,239	10,929	11,542	1.5%

Electric Demand by Class

Over the next 20 years, the residential and commercial classes are both expected to have positive demand growth, with the residential class growing faster than the commercial class, before conservation. Residential class demand growth is driven by new additional customers and projected adoption of electric vehicles. Commercial class demand growth is driven by growth in the region's technology sector, which also increases the need for support services such as health care, retail, education and other public services.

Figure 6-11: Electric Energy Demand by Class,
2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND BY CLASS, 2021 IRP BASE DEMAND FORECAST (aMW)							
Class	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
Total	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
Residential	1,248	1,300	1,392	1,497	1,609	1,722	1.4%
Commercial	954	987	1,036	1,100	1,167	1,249	1.2%
Industrial	120	121	119	117	115	114	-0.2%
Other	8	8	8	8	7	7	-0.7%
Losses	170	176	186	199	211	226	-

Electric Use per Customer

Residential use per customer[2] before conservation is expected to decline in the short term but is forecast to grow over the long term. Near-term efficiency gains and multifamily housing growth will continue to reduce electric use per customer, but the forecast projects that the increasing adoption of electric vehicles will outweigh this and create slightly positive growth, especially in the later part of the forecast. Commercial use per customer is expected to decline in the short term, due to efficiency gains as well as lingering effects from the pandemic on the commercial sector. Commercial use per customer has some positive growth in the long term due to increasing electric vehicle growth.

Figure 6-12: Electric Use per Customer, 2021 IRP Base Demand Forecast before Additional DSR

2021 IRP ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh/CUSTOMER)							
Type	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
Residential	10.3	10.4	10.5	10.7	11.0	11.2	0.4%
Commercial	63.1	63.1	63.0	63.9	65.1	66.6	0.2%
Industrial	321.9	330.5	333.6	337.3	341.4	344.7	0.3%

2 / *Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.*

Electric Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total electric customers are shown in Figure 6-13. Demand share by class is shown in Figure 6-14. The residential class is expected to increase as a percent of both total customers and total demand, and the commercial class is expected to decline as a percent of both.

Figure 6-13: December Electric Customer Count Share by Class, 2021 IRP Base Demand Forecast

ELECTRIC CUSTOMER COUNT SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2045**
Residential	88.1%	88.3%
Commercial	11.0%	10.8%
Industrial	0.3%	0.2%
Other	0.7%	0.8%

Figure 6-14: Electric Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2045**
Residential	49.9%	51.9%
Commercial	38.1%	37.6%
Industrial	4.8%	3.4%
Other	0.3%	0.2%
Losses	6.8%	6.8%

3. NATURAL GAS DEMAND FORECAST

Highlights of the base, high and low demand forecasts developed for PSE's natural gas sales service are presented below. The population and employment assumptions for all three forecasts are summarized in the section titled "Details of the Natural Gas Forecast" and explained in detail in Appendix F, Demand Forecasting Models.

Only demand-side resources implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Natural Gas Energy Demand

The 2021 IRP Natural Gas Base Demand Forecast is a forecast of both firm and interruptible demand, because this is the volume of natural gas that PSE is responsible for securing and delivering to customers. For delivery system planning, however, transport demand must be included in total demand; transport customers purchase their own natural gas, but contract with PSE for delivery.

In the 2021 IRP Base Demand Forecast, natural gas energy demand before additional DSR is projected to grow 0.8 percent per year on average from 2022 to 2041; this would increase demand from 96,156 MDth in 2022 to 112,918 MDth in 2041. This is slightly higher than the annual growth rate of 0.7 percent in the 2019 IRP Process Base Demand Forecast. While the growth rate is higher, the levels of demand are lower in the 2021 IRP Base Demand Forecast than in the 2019 IRP Process Demand Forecast because lower residential customer additions, lower residential usage in the first half of the forecast and lingering COVID-19 pandemic effects lower demand in the first part of the forecast, compared to the 2019 IRP Process Forecast.

Before additional DSR, the 2021 IRP High Natural Gas Demand Forecast projects an average annual growth rate of 1.4 percent; the Low Natural Gas Demand Forecast projects a growth rate of 0.2 percent per year.

Figure 6-15: Natural Gas Energy Demand Forecast before Additional DSR Base, High and Low Scenarios, without Transport Load (MDth)

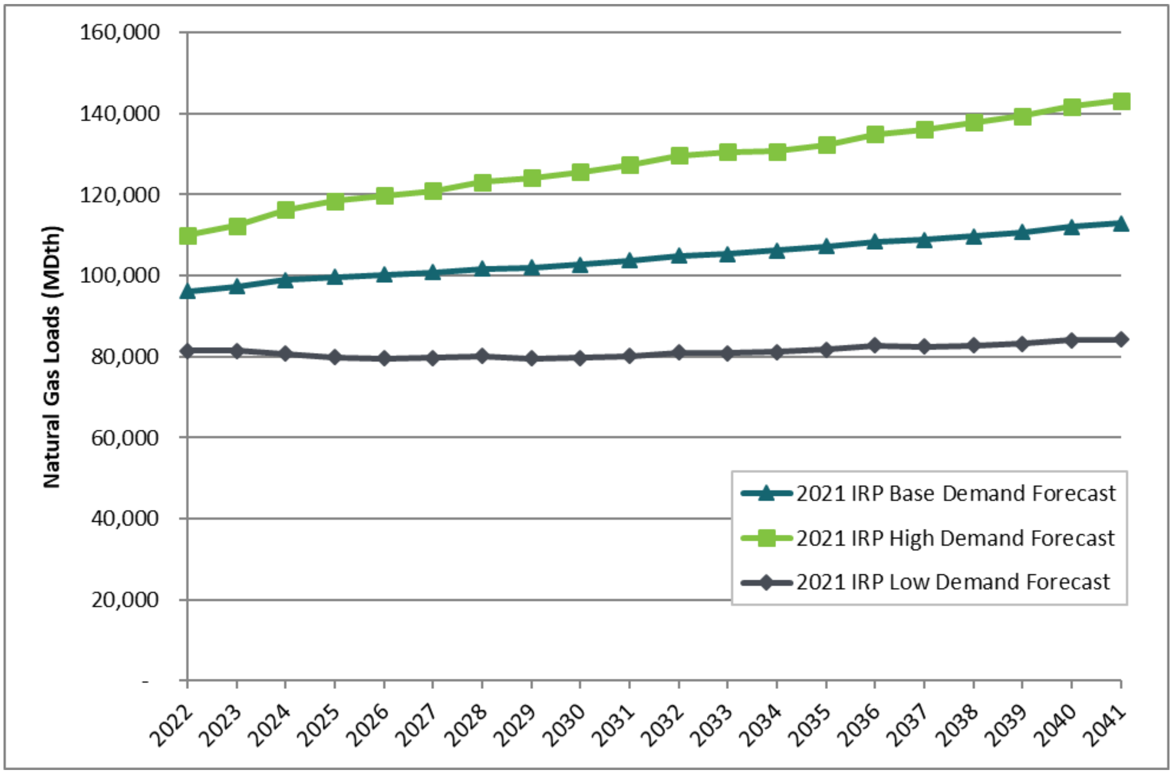


Figure 6-16: Natural Gas Energy Demand Forecast before Additional DSR (Table) Base, High and Low Scenarios without Transport (MDth)

2021 IRP NATURAL GAS ENERGY DEMAND FORECAST SCENARIOS (MDth), WITHOUT TRANSPORT						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	96,156	99,653	102,769	107,195	112,918	0.8%
2021 IRP High Demand Forecast	110,024	118,424	125,542	132,321	143,261	1.4%
2021 IRP Low Demand Forecast	81,498	79,852	79,680	81,707	84,266	0.2%

Natural Gas Peak Demand

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

For peak natural gas demand, the 2021 IRP Base Demand Forecast projects an average increase of 0.8 percent per year from 2022 to 2041; peak demand would rise from 967 MDth in 2022 to 1,130 MDth in 2041. The High Demand Forecast projects a 1.1 percent annual growth rate, and the Low Demand Forecast projects 0.6 percent.

Figure 6-17: Natural Gas Peak Day Demand Forecast before Additional DSR Base, High and Low Scenarios (13 Degrees, MDth)

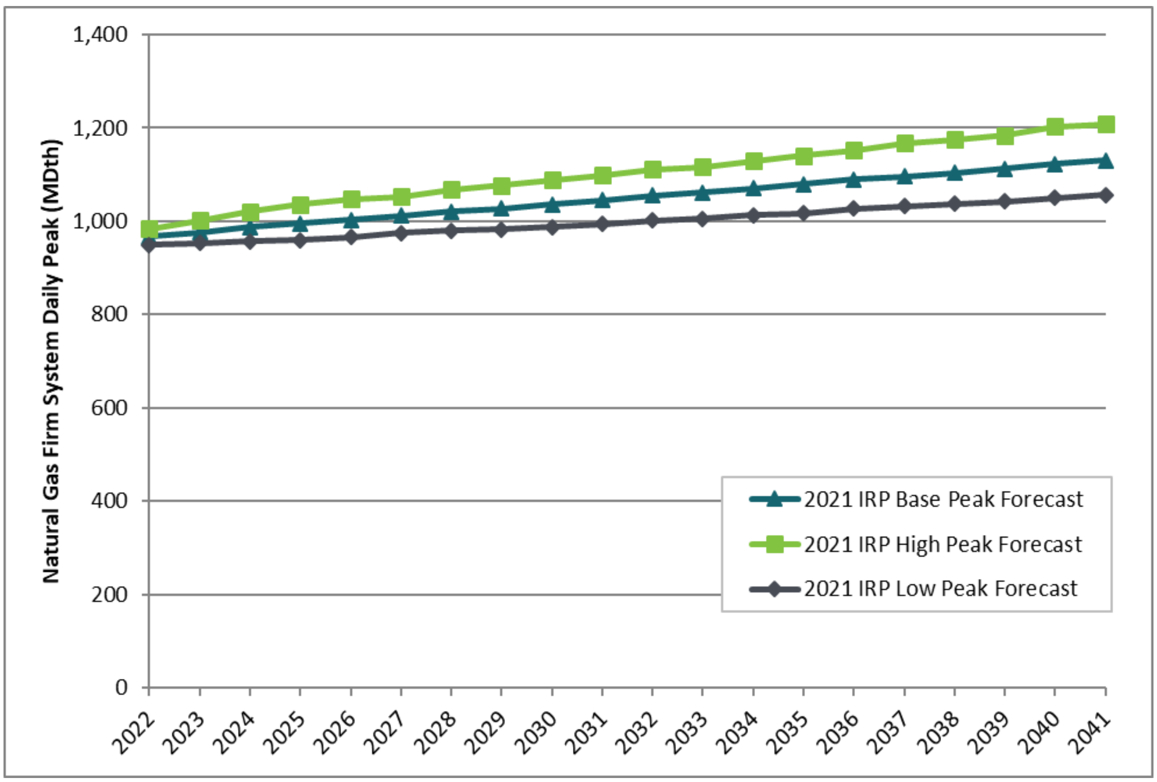


Figure 6-18: Natural Gas Peak Day Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios (13 Degrees, MDth)

2021 IRP FIRM NATURAL GAS PEAK DAY FORECAST SCENARIOS (MDth)						
Scenario	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
2021 IRP Base Demand Forecast	967	995	1,036	1,079	1,130	0.8%
2021 IRP High Demand Forecast	984	1,036	1,088	1,141	1,208	1.1%
2021 IRP Low Demand Forecast	950	960	988	1,017	1,056	0.6%

The peak demand growth rate in the 2021 Base Demand Forecast is the same as the growth rate in the 2019 IRP Process (0.8 percent), but the highest levels of peak are lower in the 2021 IRP. This is partially due to the lower customer forecast, especially in the latter years of the forecast period, and the lingering effects of the COVID-19 pandemic in the first few years of the forecast period. Also, cold winter weather in 2018 and 2019 allowed the 2021 IRP natural gas peak forecast model to better capture the sensitivity of customers to cold weather.

Figure 6-19: Firm Natural Gas Peak Day Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Daily Annual Peak (13 Degrees, MDth)

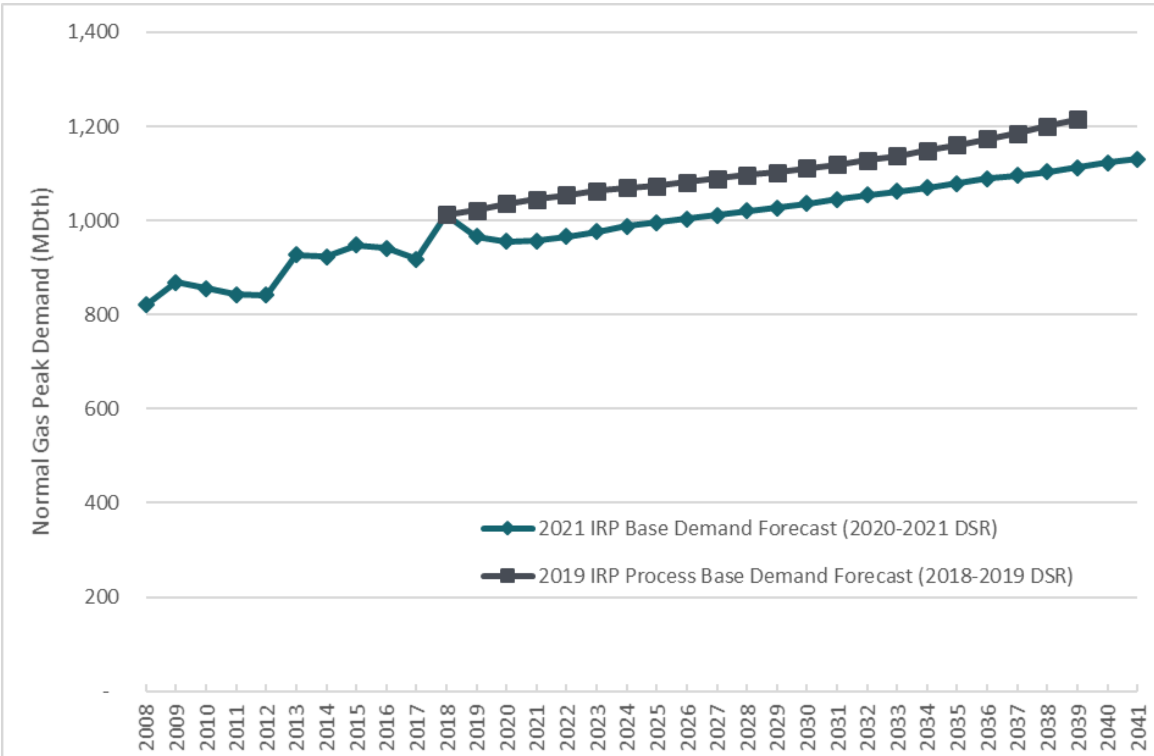


Illustration of Conservation Impacts

As explained at the beginning of the chapter, the natural gas demand forecasts include only demand-side resources implemented through December 2021, 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 energy and peak forecasts, the cost-effective amount of DSR determined in this IRP[3] is applied to the energy demand (without transport) and peak demand forecast for 2022 to 2041. To account for the 2017 General Rate Case, an additional 5 percent of conservation is also applied for that period. Forecasts with conservation are used internally at PSE for financial and system planning decisions. The results are illustrated in Figures 6-20 and 6-21, below.

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas energy demand in 2041 is reduced 10.8 percent to 100,678 Mdth.
- Natural gas energy demand grows at an average annual rate of 0.26 percent from 2022 to 2041.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas system peak demand in 2041 is reduced 9.8 percent to 1,019 Mdth.
- Natural gas system peak demand grows at an average annual rate of 0.3 percent from 2022 to 2041.

3 / For demand-side resource analysis, see Chapter 9, Natural Gas Analysis, and Appendix E, Conservation Potential Assessment.

Figure 6-20: Natural Gas Base Demand Forecast for Energy, before Additional DSR and after Applying DSR

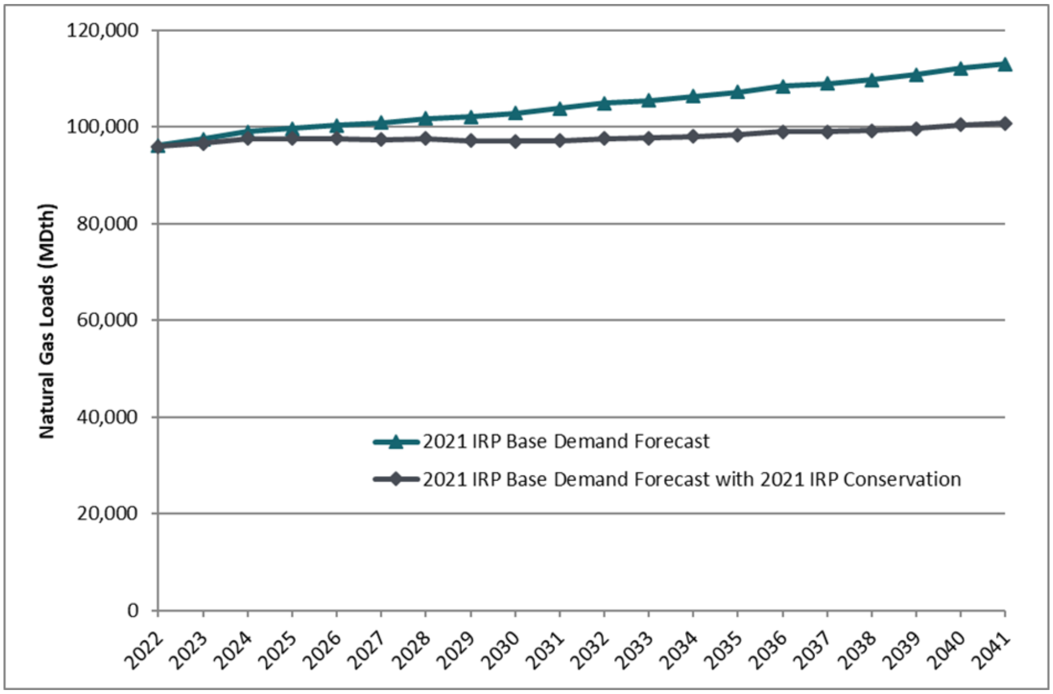
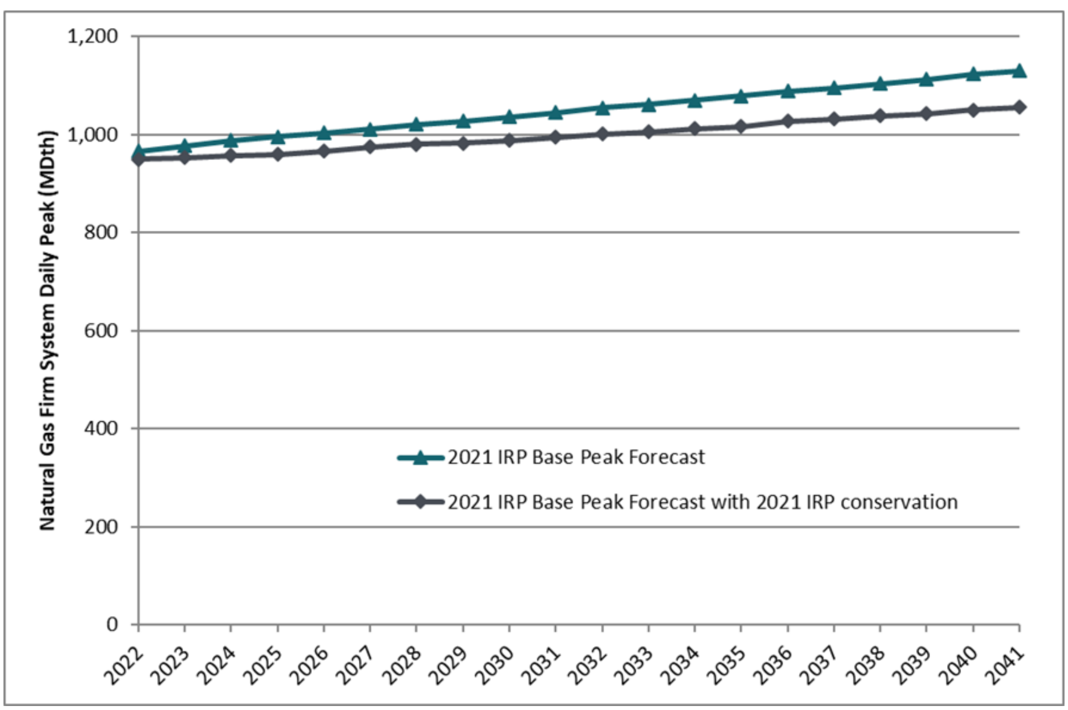


Figure 6-21: Natural Gas Peak Day Base Demand Forecast, before Additional DSR and after Applying DSR



Details of Natural Gas Forecast

Natural Gas Customer Counts

The Base Demand Forecast projects the number of natural gas customers will increase at a rate of 1.0 percent per year on average between 2022 and 2041, reaching 1.059 million customers by the end of the forecast period for the system as a whole. Overall, customer growth is slower than the 1.3 percent average annual growth rate projected in the 2019 IRP Process for 2020 to 2039.

Residential customer counts drive the growth in total customers, since this class makes up 93 percent of PSE's natural gas sales customers. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2022 to 2041. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.6 percent from 2022 to 2041. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Figure 6-22: December Natural Gas Customer Counts by Class, 2021 IRP Base Demand Forecast

DECEMBER NATURAL GAS CUSTOMER COUNTS BY CLASS 2021 IRP BASE DEMAND FORECAST						
Customer Type	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	817,317	845,918	892,765	939,222	993,155	1.0%
Commercial	57,264	58,444	60,095	61,734	63,666	0.6%
Industrial	2,244	2,191	2,103	2,016	1,910	-0.8%
Total Firm	876,825	906,553	954,963	1,002,972	1,058,731	1.0%
Interruptible	145	129	102	74	41	-6.4%
Total Firm & Interruptible	876,970	906,682	955,065	1,003,046	1,058,772	1.0%
Transport	225	225	225	225	225	0.0%
System Total	877,195	906,907	955,290	1,003,271	1,058,997	1.0%

Natural Gas Use per Customer

Table 6-23 below shows all firm use per customer at the meter.[4] Residential use per customer before conservation is slowly declining, showing a -0.1 percent average annual growth for the forecast period. Commercial use per customer is expected to rise 0.6 percent annually over the forecast horizon. Industrial use per customer has been declining in recent years and is expected to stay relatively flat. Note the commercial and industrial classes do not include interruptible or transport class usage. These classes can have very different sized customers and therefore the use per customer value can be skewed by very large customers.

Figure 6-23: Natural Gas Use per Customer before Additional DSR
2021 IRP Gas Base Demand Forecast

NATURAL GAS USE PER CUSTOMER (THERMS/CUSTOMER) 2021 IRP BASE DEMAND FORECAST						
Customer	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	784	783	766	763	765	-0.1%
Commercial	4,960	5,122	5,234	5,376	5,553	0.6%
Industrial	10,685	10,691	10,692	10,692	10,694	0.0%

4 / Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.

Natural Gas Demand by Class

Total energy demand, including transport, is expected to increase at an average rate of 0.7 percent annually between 2022 and 2041. Residential demand, which is forecast to represent 53 percent of demand in 2022, is expected to increase on average by 0.9 percent annually during the forecast period. Commercial demand, which is forecast to represent 24 percent of demand in 2022, is expected to increase 1.2 percent on average annually.

Population growth is driving residential demand growth. Commercial demand growth is driven by increases in both customer counts and use per customer. Demand in the industrial and interruptible sectors is expected to decline as manufacturing employment in the Puget Sound area continues to slow. Demand from the transport class is expected to grow slowly over time.

Figure 6-24: Natural Gas Energy Demand by Class (MDth), 2021 IRP Base Demand Forecast before Additional DSR

NATURAL GAS DEMAND (MDth) BY CLASS 2021 IRP BASE DEMAND FORECAST						
Class	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	62,949	65,092	67,228	70,454	74,690	0.9%
Commercial	28,039	29,645	31,133	32,857	34,991	1.2%
Industrial	2,390	2,335	2,242	2,149	2,038	-0.8%
Total Firm	93,379	97,072	100,604	105,460	111,719	0.9%
Interruptible	2,585	2,382	1,960	1,520	974	-5.0%
Total Firm and Interruptible	95,964	99,454	102,564	106,981	112,692	0.8%
Transport	22,169	22,445	22,414	22,574	22,948	0.2%
System Total before Losses	118,133	121,899	124,978	129,555	135,641	0.7%
Losses	237	244	250	260	272	-
System Total	118,370	122,143	125,228	129,815	135,912	0.7%

Natural Gas Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total natural gas customers are shown in Figure 6-25. Demand share by class is shown in Figure 6-26.

Figure 6-25: Natural Gas Customer Count Share by Class
2021 IRP Base Demand Forecast

NATURAL GAS CUSTOMER COUNT SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	Share in 2022	Share in 2041
Residential	93.2%	93.8%
Commercial	6.5%	6.0%
Industrial	0.3%	0.2%
Interruptible	0.02%	0.004%
Transport	0.03%	0.02%

Figure 6-26: Natural Gas Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

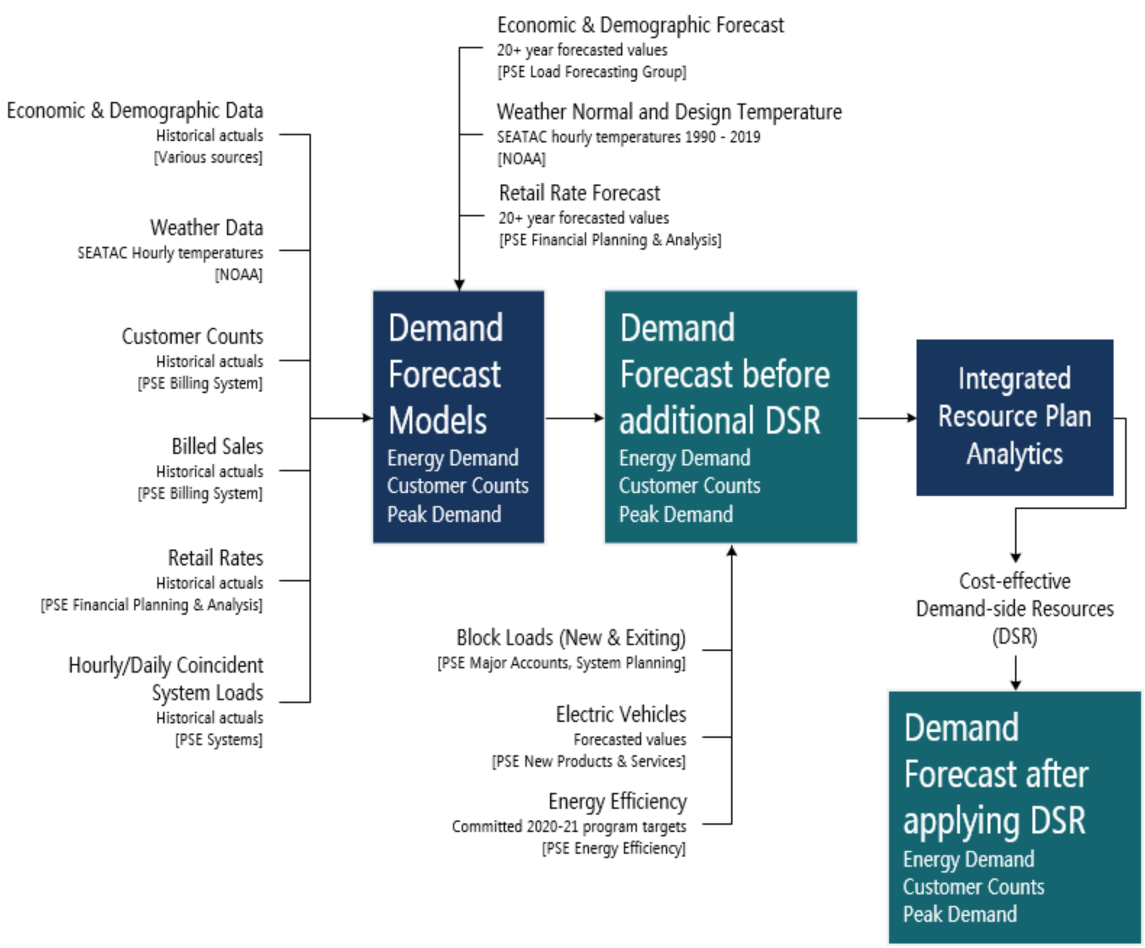
NATURAL GAS DEMAND SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	Share in 2022	Share in 2041
Residential	53.2%	55.0%
Commercial	23.7%	25.7%
Industrial	2.0%	1.5%
Interruptible	2.2%	0.7%
Transport	18.7%	16.9%
Losses	0.2%	0.2%

4. METHODOLOGY

Forecasting Process

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, households and consumer price index (CPI) for both the PSE electric and natural gas service territories. The regional economic and demographic data used in the model are built up from county level or metropolitan statistical area (MSA) level information from various sources. This economic and demographic information is combined with other PSE internal information to produce energy and peak demand forecasts for the service area. The demand forecasting process is illustrated in Figure 6-27, and the sources for economic and demographic input data are listed in Figure 6-28.

Figure 6-27: PSE Demand Forecasting Process



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 and/or service levels 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).

- Natural 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 electric and natural gas industries has historically referred to customers that acquire their own electricity or natural gas from third-party suppliers and rely on the utility for distribution service. It does not refer to natural gas fueled vehicles or electric vehicles.

Multivariate time series econometric regression equations are used to derive historical relationships between trends and drivers, which are then employed to forecast the number of customers and use per customer by class or service level. These are multiplied together to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, weather, total employment, manufacturing employment, consumer price index (CPI) and U.S. Gross Domestic Product (GDP). Demand, which is presented in this chapter, is calculated from sales and includes transmission and distribution losses in addition to sales. Weather inputs are based on temperature readings from Sea-Tac Airport. Peak system demand is also projected by examining the historical relationship between actual peaks, temperature at peaks, and the economic and demographic impacts on system demand.

***> > > See Appendix F, Demand Forecasting Models**, for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts and peak loads for electricity and natural gas; hourly distribution of electric demand; and forecast uncertainty.*

Figure 6-28: Sources for U.S. and Regional Economic and Demographic Data

<table>
<tr><th colspan="2">DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL</th></tr>
<tr><th>County-level Data</th><th>Source</th></tr>
<tr><td>Labor force, employment, unemployment rate</td><td>U.S. Bureau of Labor Statistics (BLS) www.bls.gov</td></tr>
<tr><td>Total non-farm employment, and breakdowns by type of employment</td><td>WA State Employment Security Department (WA ESD), using data from Quarterly Census of Employment and Wages
esd.wa.gov/labormarketinfo</td></tr>
<tr><td>Personal income</td><td rowspan="2">U.S. Bureau of Economic Analysis (BEA)
www.bea.gov</td></tr>
<tr><td>Wages and salaries</td></tr>
<tr><td>Population</td><td>WA State Employment Security Department (WA ESD)
esd.wa.gov/labormarketinfo/report-library</td></tr>
<tr><td>Households, single- and multi-family</td><td rowspan="2">U.S. Census
www.census.gov</td></tr>
<tr><td>Household size, single- and multi-family</td></tr>
<tr><td>Housing permits, single- and multi-family</td><td>U.S. Census / Puget Sound Regional Council (PSRC) / City Websites /
Building Industry Association of Washington (BIAW)
www.biaw.com</td></tr>
<tr><td>Aerospace employment</td><td>Puget Sound Economic Forecaster
www.economicforecaster.com</td></tr>
<tr><th>U.S.-level Data</th><th>Source</th></tr>
<tr><td>GDP</td><td rowspan="11">Moody's Analytics
www.economy.com</td></tr>
<tr><td>Industrial Production Index</td></tr>
<tr><td>Employment</td></tr>
<tr><td>Unemployment rate</td></tr>
<tr><td>Personal income</td></tr>
<tr><td>Wages and salary disbursements</td></tr>
<tr><td>Consumer Price Index (CPI)</td></tr>
<tr><td>Housing starts</td></tr>
<tr><td>Population</td></tr>
<tr><td>Conventional mortgage rate</td></tr>
<tr><td>T-bill rate, 3 months</td></tr>
</table>

High and Low Scenarios

PSE also develops high and low growth scenarios by performing stochastic simulations with stochastic outputs from PSE's economic and demographic model, using historic weather to predict future weather.

- The natural gas high and low scenarios were modelled using 250 stochastic simulations.
- The electric high and low scenarios were created with an additional 60 simulations (for a total of 310), in order to capture variation in electric vehicle loads. The electric modeling also varied the seasonal design peak temperature.

The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment and income. They also vary the equation coefficients around the standard error of the coefficient to include potential model coefficient errors. In the electric scenarios, EV assumptions were held constant in 250 of the scenarios; a high EV forecast was applied to 30 scenarios; and a low EV forecast was applied to 30 scenarios. The high and low EV forecasts were derived using assumptions from the high and low EV scenarios in the July 2020 Pacific Northwest National Lab report, *Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid*. (The base EV forecast is described in more detail in Section 5 of this chapter, Chapter 5, Key Analytical Assumptions, and Chapter 4, Planning Environment.)

High and low growth scenarios also use historic weather scenarios that can reflect higher or lower temperature conditions. Historic weather scenarios use one year of weather data randomly drawn between 1990 and 2019 in each of the simulations. In contrast, the "normal" weather used for the base scenario is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The low and high scenarios represent the 10th and 90th percentile of the simulations, respectively.

The high and low scenarios are run in the AURORA model to examine how a portfolio would change with high and low growth. The 310 electric stochastic scenarios are run in the AURORA portfolio model to test the robustness of the portfolio under various conditions. The 250 natural gas stochastic scenarios are run in SENDOUT. Detailed descriptions of the stochastics are available in Chapter 8, Electric Analysis, and Chapter 9, Natural Gas Analysis.

*> > > **See Appendix F, Demand Forecasting Models**, for a detailed discussion of the stochastic simulations.*

Resource Adequacy Model Inputs

In addition to the stochastics used to create the high and the low scenarios, PSE also develops 88 electric demand draws for the resource adequacy (RA) model. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2017 is represented in the 88 demand draws. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. RA demand draws were created for the hydro years of 2027 to 2028 and 2031 to 2032.

Additionally, the RA model examines adequacy in each hour of a given future year; therefore, the RA model inputs are scaled to hourly demand using the hourly demand model, described in detail in Chapter 7, Resource Adequacy Analysis. To account for growth in electric vehicles, each of the 88 hourly demand forecasts was first created without electric vehicle demand. Then the hourly forecast of electric vehicle demand was added to each demand forecast, to create the final 88 hourly demand forecasts.

> > > ***See Chapter 7, Resource Adequacy Analysis*** *and* ***Appendix F, Demand Forecasting Models****, for detailed discussions of the hourly model.*

Temperature Sensitivity

PSE committed to run a future temperature sensitivity as part of the IRP. To that end, in addition to the definition of normal temperature used for the base energy demand model, PSE offered three alternative average temperature assumptions to the IRP stakeholders and asked them to select one of the options for further analysis. The three options used different future temperature assumptions, representing a wide range of future outcomes. PSE then ran a sensitivity based on the option chosen.

The three temperature sensitivities presented as options were:

1. **15-year normal temperature:** PSE currently uses a 30-year normal for the base demand forecast. That is, the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. This normal weather is held constant into the future. The 15-year normal would instead use the most recent 15 years of weather data to create average monthly weather, and that weather would be held constant into the future. Option 1 results in the least amount of future warming.
2. **Historical trended temperature:** PSE contracted with Itron to examine the historic warming trend in temperatures at Sea-Tac Airport. The warming trend at Sea-Tac was determined to be linear over time at 0.4 degrees Fahrenheit warming per decade. This warming trend was then projected linearly into the future. A detailed write-up of this analysis is presented in Appendix L, Temperature Trend Study. Option 2 results in more future warming than Option 1, but less than Option 3.
3. **Council climate model:** A recent project by Bonneville Power Administration, U.S. Army Corps of Engineers, and the Bureau of Reclamation produced downscaled climate models for the Northwest region. The Northwest Power and Conservation Council (NWPCC) has been working with three of these models (CanESM2_BCSD, CCSM4_BCSD and CNRM-CM5_MACA). Each of these models is on the Representative Concentration Pathway of 8.5; some would argue this is a "business as usual" pathway, while others would argue that this is a more extreme climate warming scenario. The three models represent different amounts of warming over time. PSE presented the NWPCC model with the middle amount of warming (CCSM4_BCSD) as an option, which results in 0.9 degrees Fahrenheit of warming per decade. Option 3 represents a more extreme warming trend than Option 2.

Figure 6-29 below further describes the three future temperature options that IRP stakeholders chose from for this sensitivity.

Figure 6-29: Attributes of Temperature Sensitivity Options Compared to the Base Demand Forecast Temperatures Used

	Future Weather in Base Demand Model	Temperature Sensitivity Option 1	Temperature Sensitivity Option 2	Temperature Sensitivity Option 3
Description	30-year normal temperature	15-year normal temperature	Historical temperature trend (developed by Itron)	Council climate model
General Modeling Approach	Industry standard approach of using last 30 years of data to create flat projected temperature	Same methodology as 30-year normal, but using last 15 years of data	Uses historical warming trend to forecast future warming	Global Climate Model down-scaled to Pacific Northwest region
Weather Station Used	Sea-Tac	Sea-Tac	Sea-Tac	Sea-Tac
Historical Sea-Tac Weather Used	Last 30 years	Last 15 years	Data back to 1950 to develop a trend, 30-year normal used to define the starting point for the trend	Uses historic year of 1987 to map forecasted daily min and max temperatures to hourly temperatures
Global Climate Model, down-scaling method, and Representative Climate Pathway (RCP) assumed	NA	NA	NA, results similar to RCP 4.5	CCSM4_BCSD (Community Climate Systems Model v4: Bias Corrected Spatial Disaggregation), RCP 8.5
Energy Demand Modeling Approach	Uses last 30 years of data to create flat projected temperature for future	Uses last 15 years of data to create flat projected temperature for future	Uses historical trend to forecast warming trend in the future. Uses the middle of the last 30 years of weather as a starting point for weather trend.	Draw a trend line through the future temperatures to get warming per year. Uses the middle of the last 30 years of weather as a starting point for weather trend.
Average Warming in the Forecast Period for Energy Demand Modeling	0º F per decade	0º F per decade	0.4º F per decade	0.9º F per decade

To incorporate the future temperature options into the demand forecast, they first had to be converted into heating degree days (HDDs) and cooling degree days (CDDs). Heating and cooling degree days are a measure of how much heating or cooling is expected to be done by electric or natural gas appliances in a given month. Additional information on how to calculate heating and cooling degree days and how they factor into the demand forecast can be found in Appendix F, Demand Forecasting Models.

Figures 6-30 and 6-31 show the resulting heating degree days and cooling degree days from the three temperatures scenarios presented to the stakeholders compared to the current 30-year normal weather approach.

Figure 6-30: Annual Heating Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast

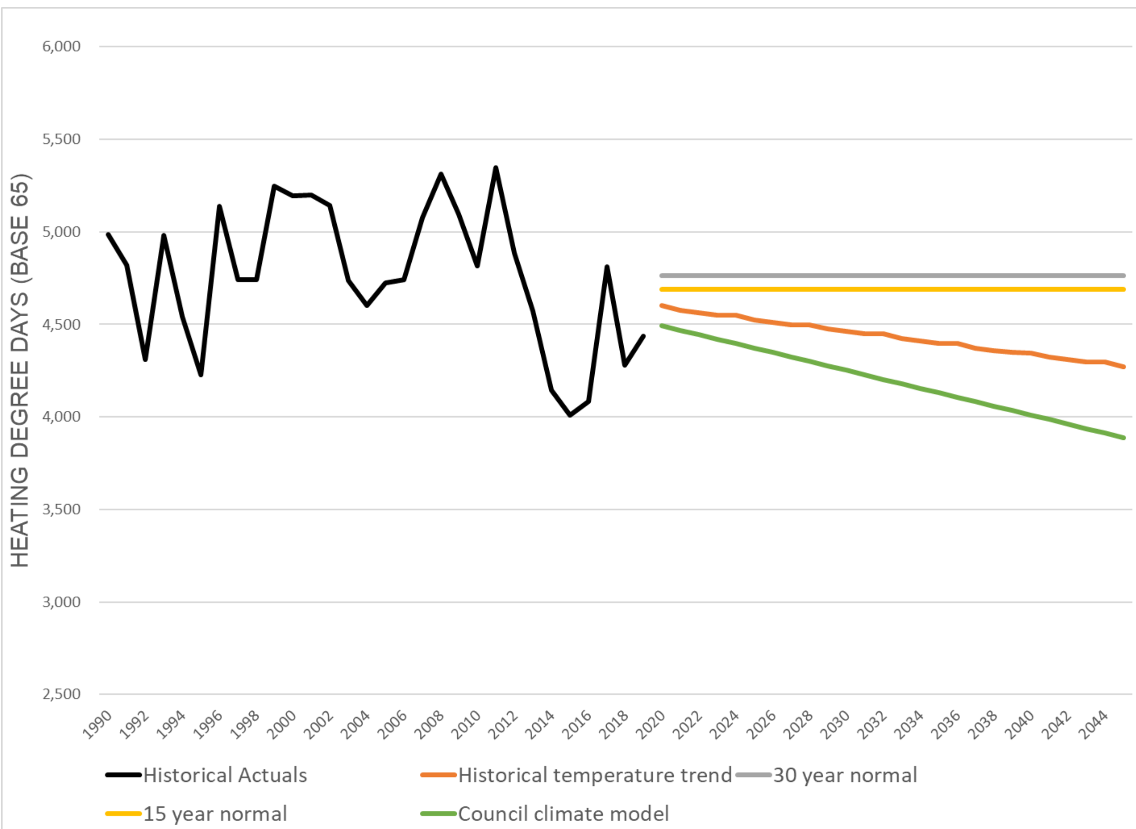
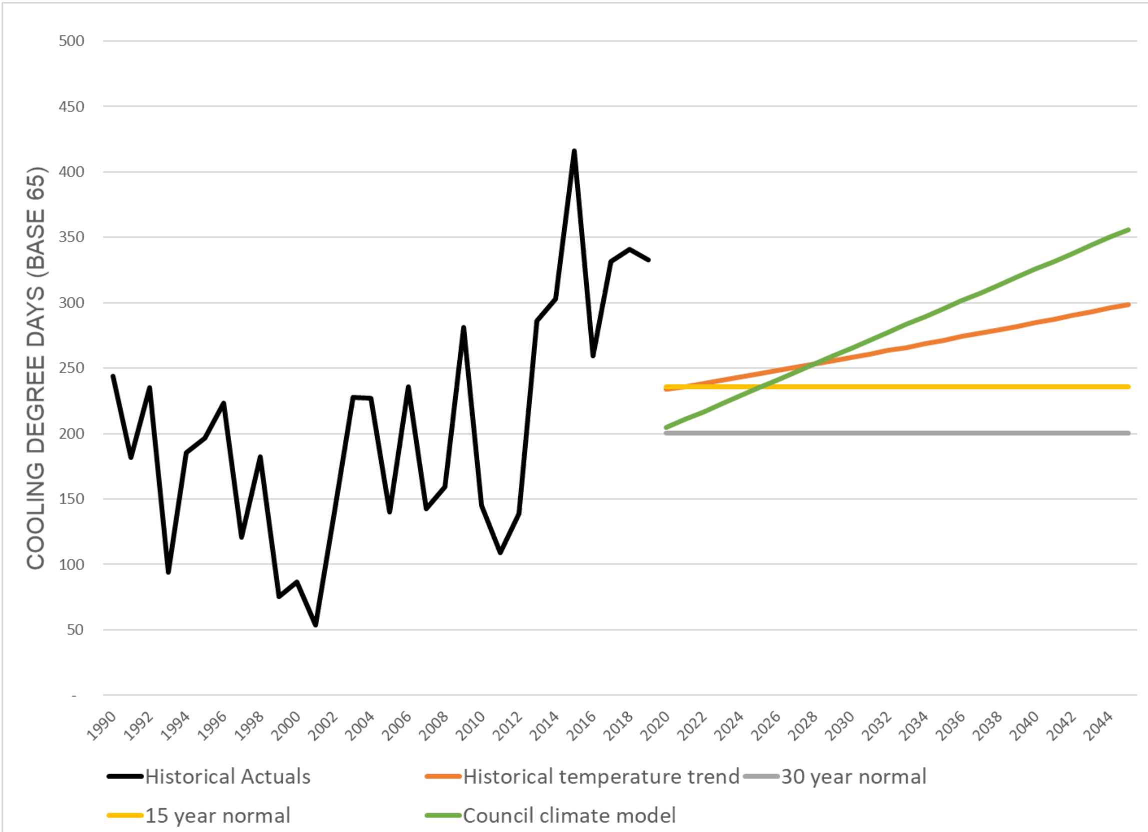


Figure 6-31: Annual Cooling Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast



Through the sensitivity prioritization process, stakeholders selected temperature sensitivity Option 3, which is based on the Northwest Power and Conservation Council climate model that assumes 0.9 degrees Fahrenheit warming per decade. Figures 6-32 and 6-33 compare the IRP base electric and natural gas energy demand forecasts with the forecasts that result from using this future temperature assumption.

With climate change, average temperatures are increasing over time. However, extreme weather events, both hot and cold, may still occur. Therefore, PSE did not change the peak temperature assumptions for this analysis, and therefore the peak demand did not change with this analysis.

In addition to the electric and gas energy demand forecasts, the electric RA model was run for this temperature sensitivity. The RA model examines a number of possible future conditions, including temperatures. The base RA model uses 88 historic temperature years: to create a wider range of possible future temperatures, PSE used all three of the NWPCC models, which mirrors the range of temperatures in NWPCC's RA analysis.

To create the RA model inputs temperatures from all three NWPCC models were used (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA). Weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RA model run, while weather from 2030 to 2039 was used for the 2031 to 2032 RA model run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model.

Figure 6-32: Base Electric Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast (aMW)

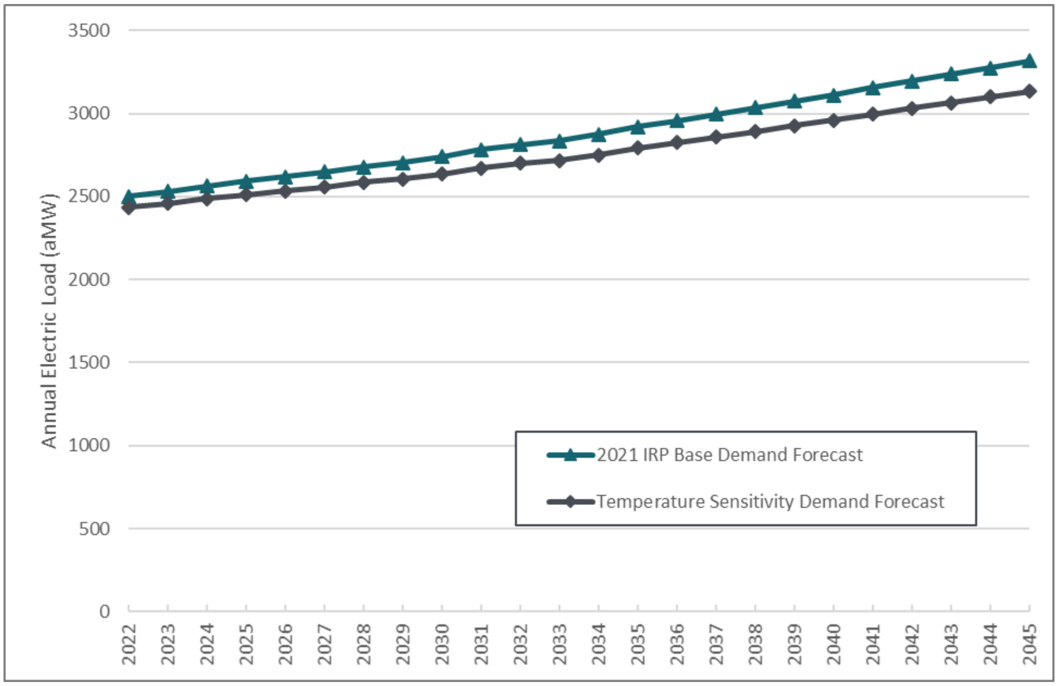
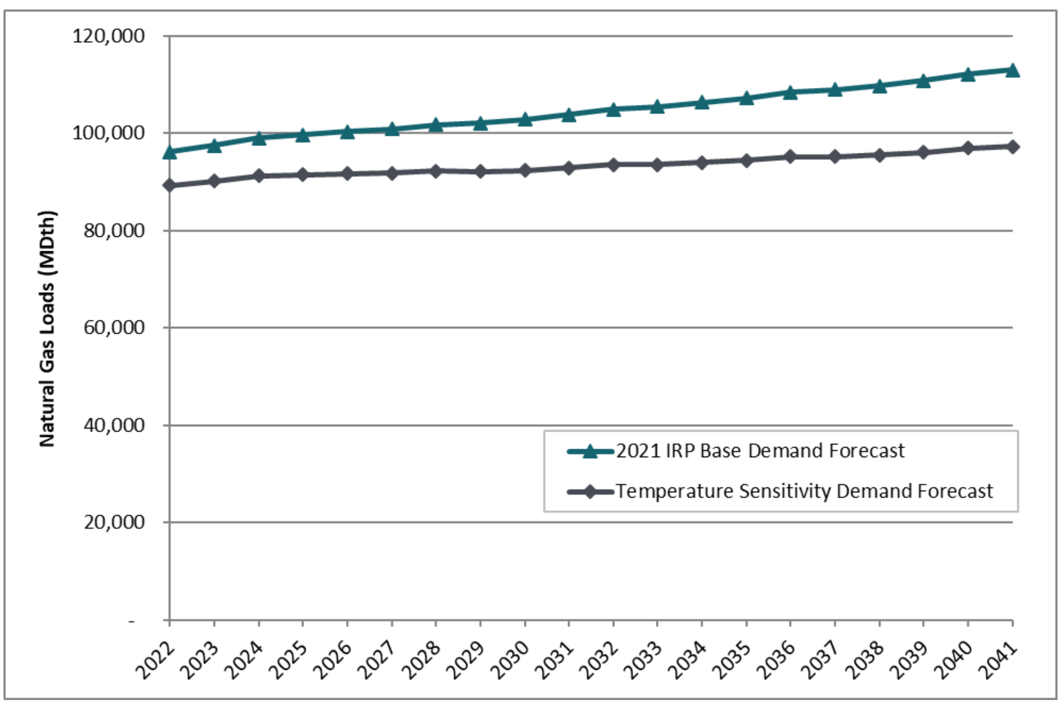


Figure 6-33: Base Natural Gas Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast, without Transport Load (MDth)



Updates to Inputs and Equations

Updates to the demand forecast inputs and equations made since the 2019 IRP Process are summarized below.

POPULATION FORECAST. In previous IRPs, PSE has used Moody's forecast of U.S. population along with the economic and demographic model to forecast population in the electric and natural gas service areas. This has been under-forecasting population growth in the Puget Sound Area. In the 2021 IRP, population forecast is built up from county population forecasts that the Washington Employment Security Department (WA ESD) publishes. This better aligns the electric and natural gas forecasts of residential customers with population growth. Therefore, as population growth slows in the later part of the forecast period, the residential customer counts also slow.

ELECTRIC COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES. To better model the different segments of the electric commercial and industrial classes, the classes were broken out into smaller segments, including small/medium, large, high voltage and commercial lighting. Customer counts and use per customer were modeled for each segment individually, then added up to create the total customer counts and energy demand for each class.

SUMMER PEAK MODELING. The electric peak model was updated to include an index of air conditioning (AC) saturation in lieu of a linear trend as a proxy of past and future AC adoption. The AC index is created by using PSE's historical Residential Characteristics Survey (RCS) data points and calibrating to the U.S. Energy Information Administration (EIA) trend (West Region). The model driver was adopted to better track the non-linear nature of historical and future AC adoption.

MODELING SOFTWARE UPDATE. PSE transferred the demand forecast model from the Eviews application to energy forecasting software developed by Itron. The transition to Itron software enables PSE to manage the forecast input and output data in a database format (rather than separate Excel spreadsheets) and is modular in nature, organizing the forecasting steps in a consistent fashion across models. The modeling approach and methodology has not materially changed with this transition.

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, electric vehicles and various other 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 an 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, the IRP forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. The May 2020 Moody's forecast was used for this IRP.

The Moody's forecast calls for:

- A drop in employment and a sharp rise in unemployment in the second quarter of 2020 due to the COVID-19 pandemic. Unemployment stays above 6 percent until the first quarter of 2022, and is above 5 percent until the first quarter of 2023.
- After 2023 Moody's predicts the economy grows modestly as the U.S. population growth rate slows in the long term.
- U.S. GDP to continue to grow over the forecast period with 2.2 percent average annual growth from 2022 to 2045. This growth rate is higher compared to the Moody's forecast used in the 2019 IRP Process, which projected 2.0 percent average annual growth, but some of this growth is from the projected recovery from COVID-19.

- Average annual population growth of 0.4 percent for 2022-2045. This is down from the 0.6 percent growth rate Moody's forecast in the 2019 IRP Process for 2020-2039. However, this IRP did not use Moody's population projections because PSE's regional projections based on Moody's U.S. forecasts were consistently under-forecasting population growth in the electric and natural gas service areas. Instead, PSE used the Washington State Employment Security Department (WA ESD) population projections by county for the electric and natural gas service areas.

Moody's identified possible risks that could affect the accuracy of this forecast:[5]

- The Moody's forecast assumes that COVID-19 infections peak in May 2020 and begin to abate in July 2020. There is a downside risk if additional outbreaks occur, which are possible until a vaccine is widely available.
- Re-imposition of social distancing and forced business closures could derail any recovery that the economy has made.
- Moody's assumes that government and lawmakers provide monetary and fiscal responses to the pandemic to stabilize financial markets. The timing and size of this response is critical for determining the shape of the recovery.
- Changes to the economies of other global powers could affect the U.S. economy, especially as the demand for goods and services changes with the pandemic.
- Retaliations to U.S. tariffs could cause lower U.S. and global growth.

Regional Economic Outlook

PSE prepares regional economic and demographic forecasts using econometric models based on historical economic data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

PSE's 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. PSE serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties.

Within PSE's service area, demand growth is uneven. Most of the economic growth is driven by growth in the high tech, information technology or retail (including online retail) sectors; supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for half or more of the system's electric and

5 / *Moody's Analytics (2020, May) Forecast Risks. Precis U.S. Macro. Volume 25 Number 2.*

natural gas sales demand today. Other counties are growing, but typically more slowly, and have added fewer jobs.

Electric Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2021 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate of 0.6 percent between 2022 and 2045, which is the same as the annual growth rate forecasted in the 2019 IRP Process.
- Local employers are expected to create about 310,000 total jobs between 2022 and 2045, mainly driven by growth in the commercial sector, compared to about 257,000 jobs forecasted in the 2019 IRP Process.
- Manufacturing employment is expected to decline by 0.1 percent annually on average between 2022 and 2045 due to the outsourcing of manufacturing processes to lower wage or less expensive states or countries, and due to the continuing trend of capital investments that create productivity increases.
- An inflow of 975,000 new residents (by birth or migration) is expected to increase the local area population to 5.3 million by 2045, for an average annual growth rate of 0.9 percent. This growth rate is not constant over time, and the population growth rate is expected to be higher in the near term and lower in the long term. However, on average, this growth rate is higher than the 2019 IRP Process forecast, which projected an average annual population growth of 0.6 percent that would have resulted in 4.6 million electric service area residents by 2039. The 2021 forecast has a different growth rate because the population forecast in this IRP is based on the WA ESD forecast of population instead of Moody’s population forecast.

Local economists at Western Washington University have identified possible risks to the regional economy:[6, 5]

- It is unknown when the COVID-19 vaccine will achieve widespread immunity.
- Employers are taking on debt to make ends meet as their customers are spending less.
- Unforeseen layoffs from struggling businesses could slow economic recovery.
- Political and social unrest will have unknown effects on the economy.
- Lingering U.S.-China tension could affect the economy.

HIGH SCENARIO OUTLOOK. For the Electric High Demand Forecast scenario, population grows by 1.1 percent annually from 2022 to 2045, and employment grows by 0.8 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Electric Low Demand Forecast scenario, population grows by 0.7 percent annually from 2022 to 2045. Employment grows 0.3 percent annually from 2022 to 2045.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 6-34 and 6-35.

5 / Western Washington University Center of Economic and Business Research (2020, June) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 2.

6 / Western Washington University Center of Economic and Business Research (2020, March) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 1.

Figure 6-34: Population Growth, Electric Service Counties

2021 IRP POPULATION GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,334	4,482	4,715	4,936	5,134	5,310	0.9%
2021 IRP High Demand Forecast	4,398	4,609	4,902	5,158	5,398	5,609	1.1%
2021 IRP Low Demand Forecast	4,267	4,363	4,536	4,723	4,869	4,989	0.7%

Figure 6-35: Employment Growth, Electric Service Counties

2021 IRP EMPLOYMENT GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	2,172	2,268	2,327	2,385	2,436	2,482	0.6%
2021 IRP High Demand Forecast	2,365	2,488	2,562	2,669	2,744	2,814	0.8%
2021 IRP Low Demand Forecast	1,996	2,047	2,088	2,103	2,145	2,159	0.3%

Natural Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Natural Gas Demand Forecast scenario, population grows by 1.0 percent annually from 4.5 million people in 2022 to 5.45 million people by 2041. Employment is expected to grow by 1.2 percent annually from 2022 to 2041.

HIGH SCENARIO OUTLOOK. For the High Natural Gas Demand Forecast scenario, population grows by 1.2 percent annually from 2022 to 2041, and employment grows by 2.1 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Natural Gas Demand Forecast scenario, population grows 0.8 percent annually from 2022 to 2041, and employment grows 0.2 percent annually.

The Base, High and Low population and employment forecasts for PSE's natural gas sales service area are compared in Figures 6-36 and 6-37.

Figure 6-36: Population Growth, Natural Gas Service Counties

2021 IRP POPULATION GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	4,542	4,703	4,953	5,197	5,452	1.0%
2021 IRP High Demand Forecast	4,619	4,842	5,159	5,437	5,766	1.2%
2021 IRP Low Demand Forecast	4,461	4,575	4,769	4,955	5,146	0.8%

Figure 6-37: Employment Growth, Natural Gas Service Counties

2021 IRP EMPLOYMENT GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	2,225	2,368	2,497	2,628	2,780	1.2%
2021 IRP High Demand Forecast	2,478	2,748	3,043	3,257	3,655	2.1%
2021 IRP Low Demand Forecast	1,975	1,987	1,989	2,022	2,042	0.2%

Other Assumptions

Weather

For the IRP Base Demand scenario, the energy demand 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 2019. The 2021 IRP forecast methodology, as described in this chapter and Appendix F, Demand Forecasting Models, employs various thresholds of heating and cooling degree days, consistent with industry practices. Employing monthly degree days helps estimate the amount of weather-sensitive demand in the service area. PSE rolls forward the 30-year period employed in each IRP to capture recent climate conditions. To create the High and Low Demand Forecasts historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

In this IRP, PSE is including a temperature sensitivity that explores how changing heating and cooling degree days could affect loads in the future as the climate warms. This sensitivity is described in detail in Chapter 5, Key Analytical Assumptions.

Additionally, PSE is following and participating in the regional efforts of the Northwest Power and Conservation Council to include climate change in its planning process. These efforts include both forecasting future temperatures as well as considering secondary effects of climate change on population and economic growth. Future IRPs will incorporate climate change impacts as regionally accepted information becomes available.

COVID-19 Adjustments

In early March 2020, the COVID-19 pandemic reached the Puget Sound region in earnest. The governor issued a "Stay Home, Stay Healthy" order on March 23 that had immediate impacts on the local economy. To account for the pandemic's effects on the economy, customer counts and demand, PSE incorporated the May 2020 Moody's Analytics economic forecast, the most current Moody's forecast at the time the IRP forecast was developed. Moody's forecast included the following economic and epidemiological assumptions about the severity of the disease and its effects on the economy: that new infections would abate in July 2020 without a second wave of infections; that unemployment would spike in 2Q 2020; and that the recovery from the resulting recession would last through 2023, when unemployment would return to around 5 percent.

The typical relationship between historic economic assumptions and the forecast was not able to capture all of the immediate impacts to the demand forecast for year 2020, so PSE made additional assumptions and adjustments to reflect the impacts of COVID-19 by tracking the observed effects on each customer class. For the commercial class, PSE assessed the potential impacts by building type, since some sectors of the economy were hit harder than others. Adjustments from these additional analyses were then aligned with the epidemiological assumptions made by Moody's May 2020 forecast.

After 2020, no additional adjustments were made above and beyond the effects of the economic forecast that was incorporated into the demand forecast using the macroeconomic variables. The result was a slow recovery over the following few years and a recovered economy by 2024, with lingering effects from the recession persisting thorough out the remainder of the forecast.

PSE performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes that were the basis for the high and low forecasts. Since the IRP determines the resource need starting in 2022, the high and low forecasts show alternative ways the pandemic could resolve in the future.

Loss Factors

The electric loss factor is 6.8 percent, compared to 7.1 percent in the 2019 IRP Process. The gas loss factor in this IRP is 0.2 percent, which is the same as the loss factor in the 2019 IRP Process. The loss factors assumed in the demand forecast are system-wide average losses during normal operations for the past 2 to 3 years.

Block Load Additions

Beyond typical economic change, the demand forecast also takes into account known major demand additions and deletions that would not be accounted for though typical load growth in the forecast. The majority of these additions are from major infrastructure projects. These additions to the forecast are called block loads and they use information provided by PSE's system planners. The adjustments to non-transport customers add 91.1 MW of connected demand by 2025 for the electric system as a whole. These block loads are included in the commercial class, and King County has the majority of the additions.

The natural gas forecast includes block loads of 0.1 MDth per day which are included in the industrial class.

Schedule Switching

In addition to block loads, PSE accounts for customers that switch between rate schedules. Customers that purchase their own electricity or natural gas are called transportation customers and they rely on PSE for distribution services. Because PSE is not responsible for acquiring supply resources for electric or natural gas transportation customers, in the IRP they are removed from the forecast before supply-side resource need is determined.

Interruptible Loads

PSE has 152 electric interruptible customers; six of these are commercial and industrial customers and 146 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 14 MW of coincident peak demand. In this IRP, PSE did not count the 14 MW of DR potential, but this will be included in future modeling.

For a number of natural gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was assumed when forecasting peak natural gas demand.

Electric Vehicles

An electric vehicle (EV) forecast was created for PSE by Guidehouse in early 2020. The forecast assumes 60,000 customer-owned light duty EVs on the road in PSE's service area in 2022, increasing to 705,000 EVs in 2045. Annual energy sales from new electric vehicles total 83,000 MWh in 2022 and 1,960,000 MWh in 2045. Initially, 81 percent of this charging is assumed to occur on residential accounts, while the remaining 19 percent is assumed to occur through commercial accounts. During the forecast period this percentage changes as charging at commercial locations becomes more widely available, resulting in 56 percent charging on residential accounts and 44 percent charging on commercial accounts in 2045. Electric vehicles are an emerging technology, thus PSE anticipates this forecast will be revised on an ongoing basis in the future. The additional demand by electric vehicles grows to an 8 percent share of total peak demand by 2045, before including cost-effective DSR identified in the 2021 IRP. Figure 6-38 below shows the December evening peak demand and annual average energy demand from new electric vehicles. Figure 6-39 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Figure 6-38: Electric Vehicle Peak Demand and Average Energy Demand from New Vehicles (aMW, MW)

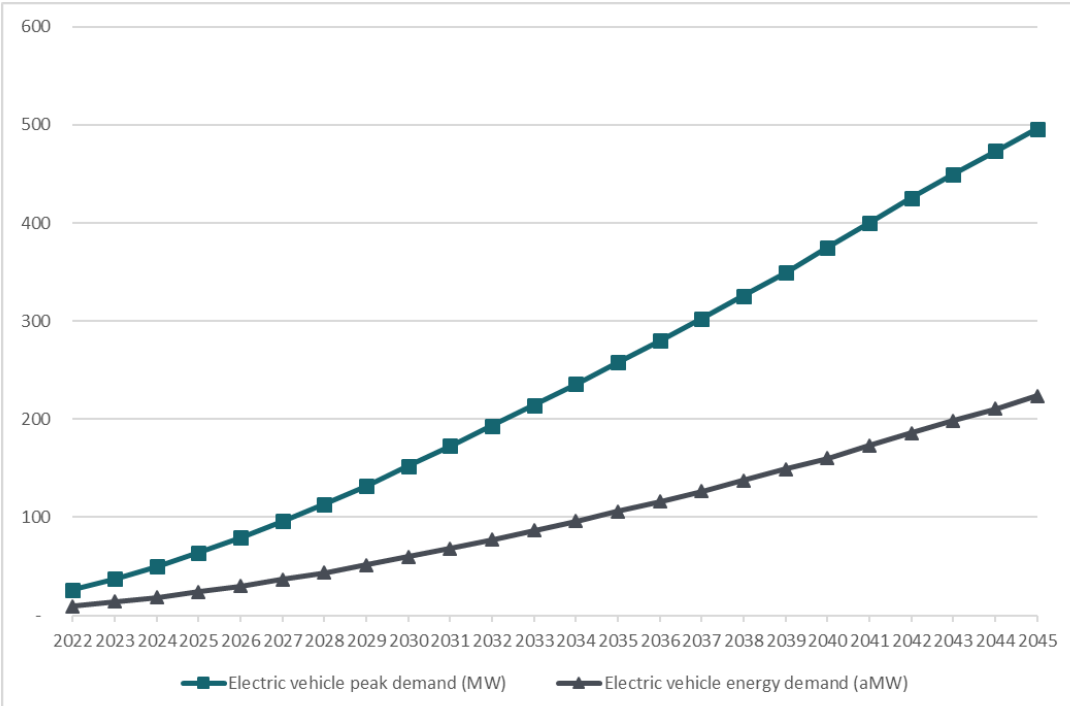
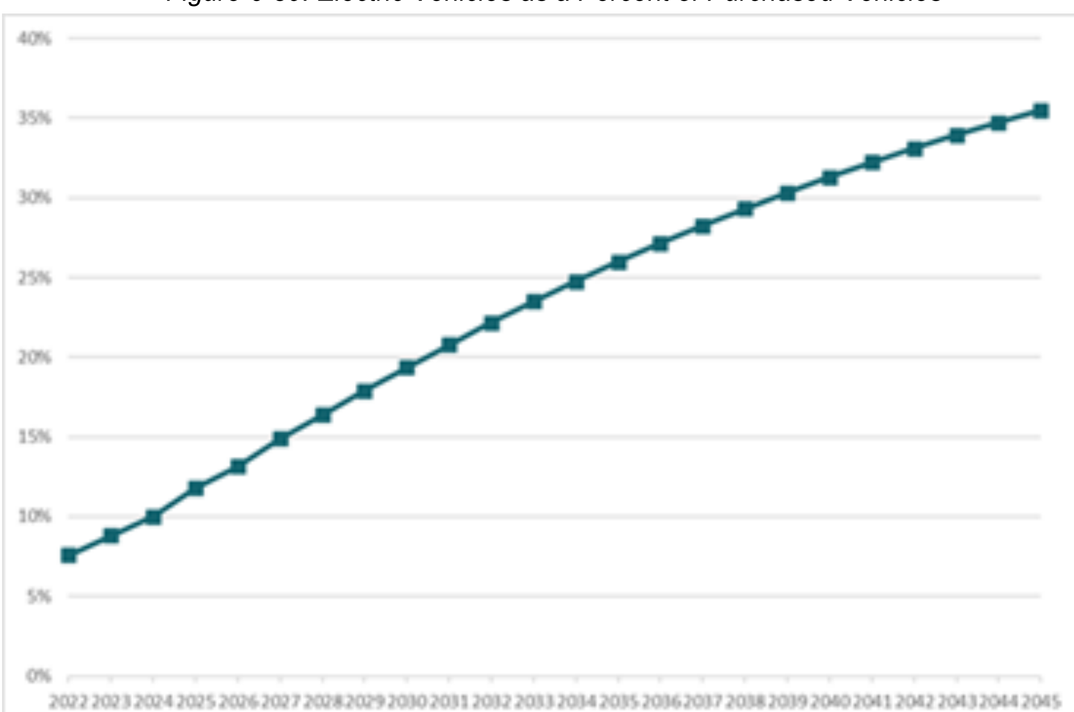


Figure 6-39: Electric Vehicles as a Percent of Purchased Vehicles



Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2021 IRP Natural Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2022, this adds 365 MDth to the forecast. This demand is expected to grow at an average annual rate of 3.5 percent, based on the Annual Energy Outlook 2019 published by the U.S. Department of Energy.

Retail Rates

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 those appliances 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.

Distributed Generation

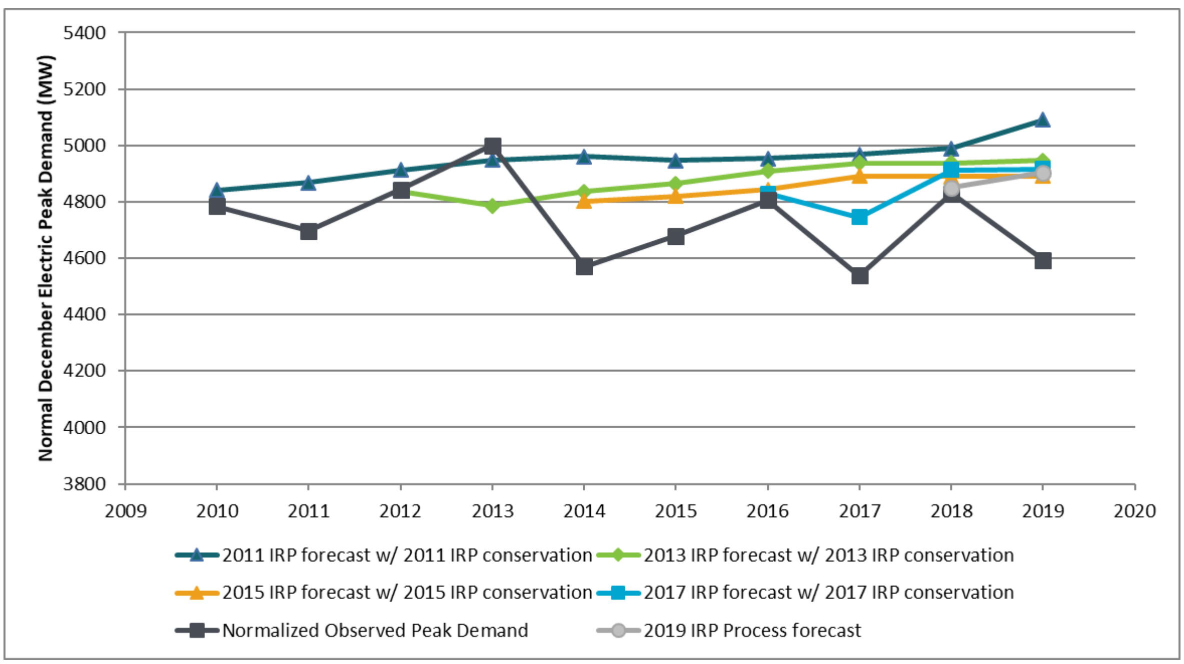
Distributed generation, including customer-level generation via solar panels, was not included in the demand forecast; this energy production is captured in the IRP modeling process as a demand-side resource. A description is included in the Appendix E, Conservation Potential Assessment and Demand Response Assessment.

6. RETROSPECTIVE OF PREVIOUS DEMAND FORECASTS

IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6-40 compares the 2011, 2013, 2015, 2017 and 2019 IRP Process electric Base Scenario peak demand forecasts after DSR with normalized[7] actual observations. The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed. The percent difference of normalized actual values compared to each IRP forecast is presented for each year in Figure 6-41.

Figure 6-40: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



7 / *Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.*

Figure 6-41: Observed Electric Peak Demand and Difference from Previous IRP Forecasts

ELECTRIC DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	2011 IRP	2013 IRP	2015 IRP	2017 IRP	2019 IRP Process
2010	1.2%				
2011	3.6%				
2012	1.5%	-0.1%			
2013	-1.0%	-4.3%			
2014	8.5%	5.8%	5.1%		
2015	5.7%	4.0%	3.0%		
2016	3.1%	2.1%	0.8%	0.5%	
2017	9.5%	8.8%	7.8%	4.6%	
2018	3.3%	2.3%	1.2%	1.7%	0.5%
2019	10.8%	7.7%	6.5%	7.1%	6.8%

Similarly, weather normalized actual natural gas peak demand is compared to the natural gas peak forecasts after conservation from the 2011, 2013, 2015, 2017 IRPs and the 2019 IRP Process in Figures 6-42 and 6-43.

Figure 6-42: Observed Weather Normalized Natural Gas Peak Demand Compared to Previous IRP Forecasts of Natural Gas Peak Demand

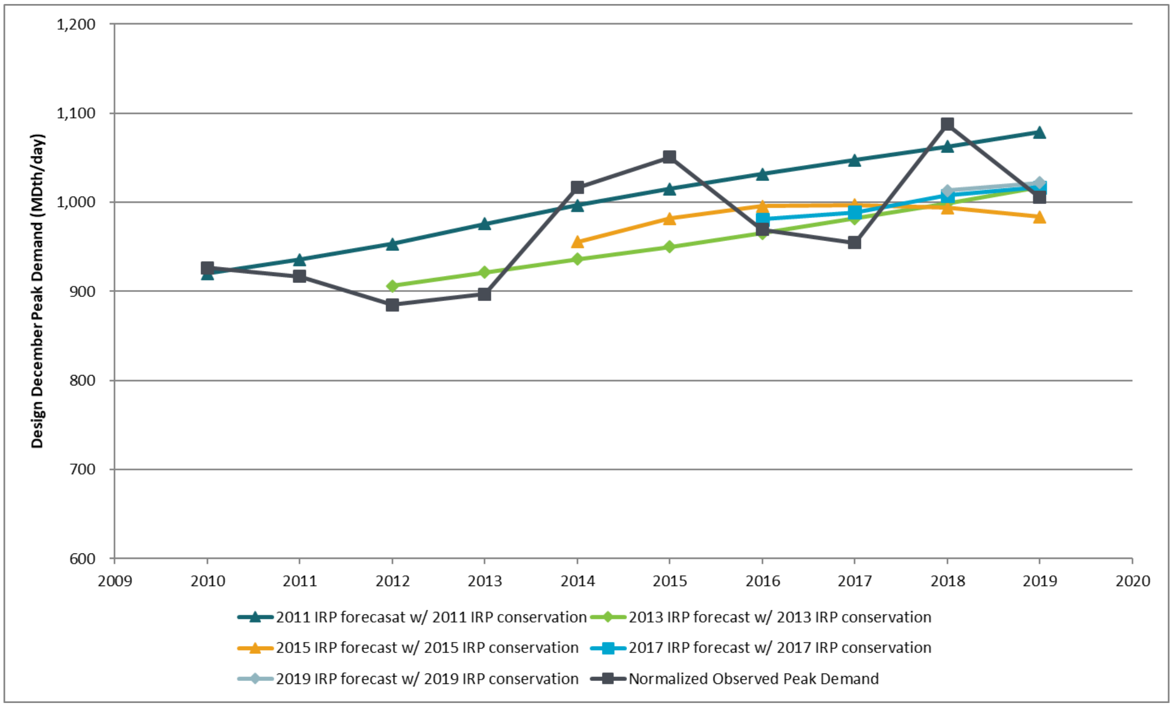


Figure 6-43: Observed Natural Gas Peak Demand and Difference from Previous IRP Forecasts

NATURAL GAS DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**	**2019 IRP Process**
2010	-0.7%				
2011	2.0%				
2012	7.8%	2.4%			
2013	8.8%	2.7%			
2014	-2.0%	-7.9%	-5.6%		
2015	-3.4%	-9.6%	-6.1%		
2016	6.4%	-0.4%	3.2%	1.2%	
2017	9.7%	2.8%	5.0%	3.6%	
2018	-2.3%	-8.2%	-8.2%	-7.4%	-6.9%
2019	7.3%	1.1%	-1.7%	1.1%	1.6%

Reasons for Forecast Variance

As explained throughout this chapter, the IRP peak demand forecasts are based on forecasts of key demand drivers that include expected economic and demographic behavior, conservation, customer usage and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. These differences are explained below.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare the Moody's forecasts of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP Process with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP Process, forecasts of housing starts are no longer used as a driver in the demand forecast; instead, forecasts of population based on WA ESD data are now used to forecast population in PSE's service territories. The Moody's forecast of housing starts and population from May 2020 are included in the two charts below for comparison

Additionally, while the Moody's forecast used in the 2019 IRP Process did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects from the COVID-19 pandemic. Therefore, Moody's forecasts used prior to the 2021 IRP have likely over-estimated economic growth in 2020 and the following few years. It is likely that the full extent of the pandemic's repercussions on the economy and energy demand will not be known during this IRP cycle.

Figure 6-44: Moody's Forecasts of U.S. Housing Starts Compared to Actual Housing Starts

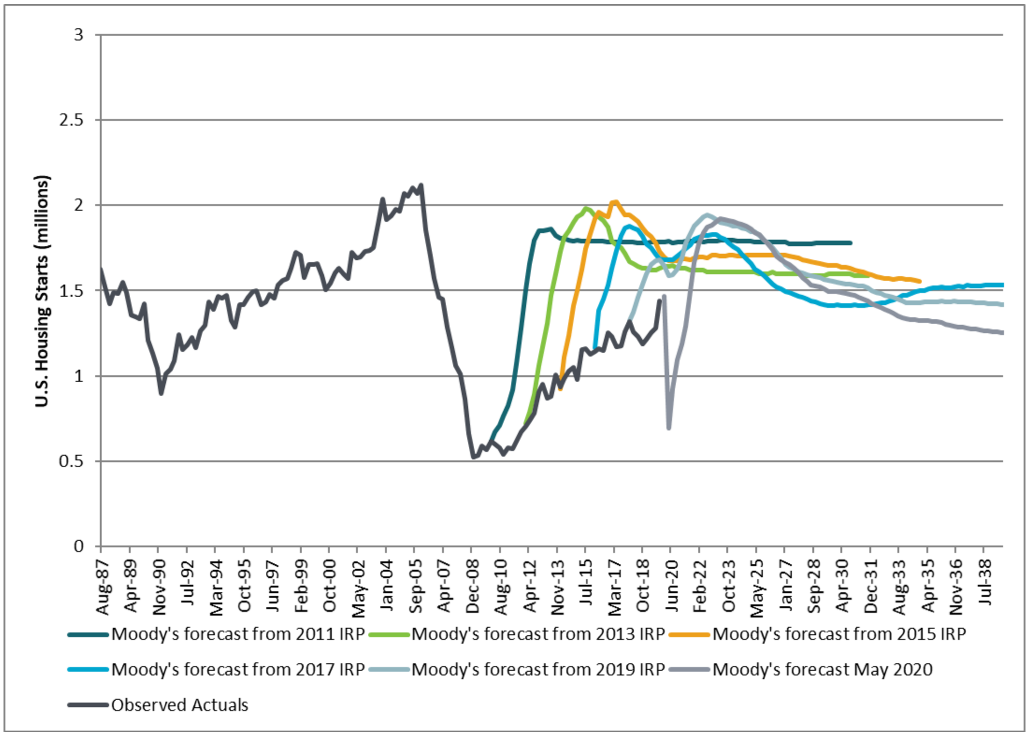
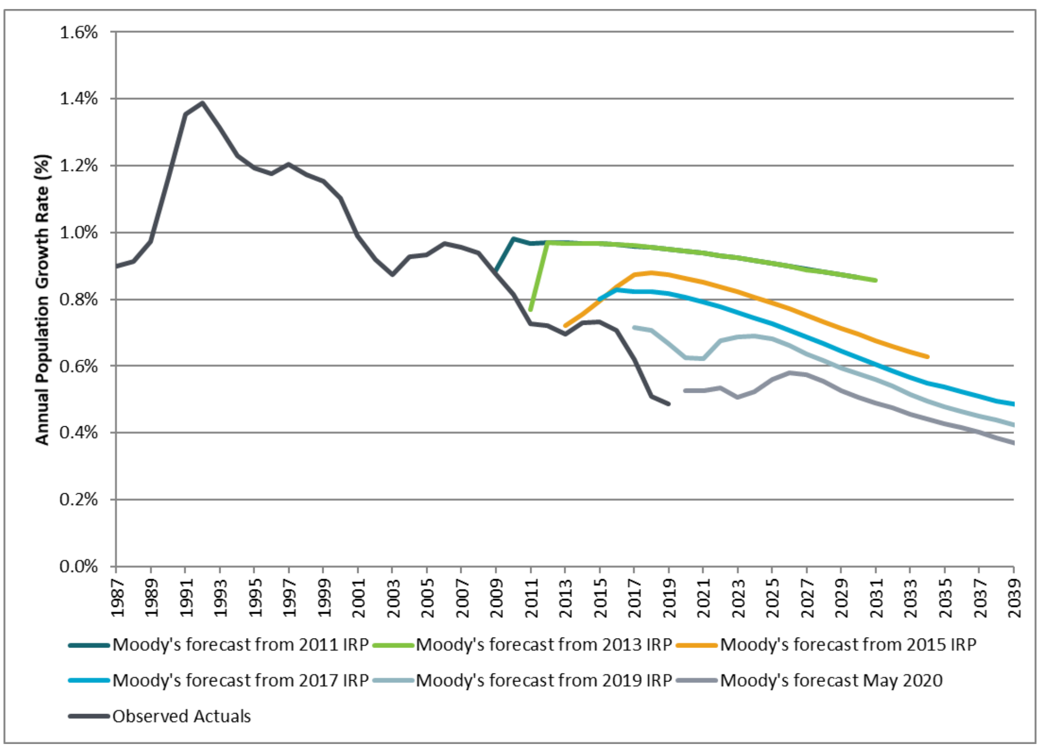


Figure 6-45: Moody's Forecasts of U.S. Population Growth Compared to Actual Population Growth



Conservation and Customer Usage

The comparison in Figures 6-40 and 6-42 of weather normalized peak observations to the IRP peak demand forecasts after conservation assumes that the forecasted conservation will be implemented. However, consumers can adopt energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted. Additionally, conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.

Also, due to the Global Settlement from the 2013 General Rate Case (GRC) PSE and the 2017 GRC, PSE decisions accelerate electric and natural gas conservation, respectively, by 5 percent each year. This is additional conservation that is not taken into account in this comparison of IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. For each IRP, the normal weather assumption is updated by rolling off two older years of data and incorporating two new years of weather data into the 30-year average. Over time, normal heating degree days have been declining and normal cooling degree days have been increasing. As temperatures change over time, the forecast of demand with normal weather changes.

Additionally, over time our customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, natural gas peaks in 2010, 2013, 2016, and 2017 fell on weekends. Natural gas peaks in 2010, 2012, and 2015 fell on New Year's Eve and the 2019 peak fell on Boxing Day (the day after Christmas). Additionally, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend, in 2015 it fell on New Year's Eve, and in 2019 it fell on the day after Christmas. Usage on these days is likely to be different than usage on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, those forecasts would be expected to be higher than the actual peak demand.

7 Resource Adequacy Analysis

This appendix provides an overview of PSE's resource adequacy modeling framework and how it aligns with other regional resource adequacy analyses.

Contents

1. OVERVIEW

The energy supply industry is in a state of transition as major decarbonization policies are implemented in most states. Significant amounts of coal-fired generation is being retired, and new intermittent, renewable generation is being constructed. These changes will cause PSE and other utilities to significantly change how they plan, especially with regard to resource adequacy. To maintain confidence in the wholesale market and ensure that sufficient resources are installed and committed, PSE, along with Northwest Power Pool members, is designing and implementing a regional resource adequacy program. The detailed design phase of the resource adequacy program is under way, with completion expected in mid-2021. As more details are understood, PSE will begin the evaluation of various resource adequacy elements in the resource adequacy analysis included in the 2021 IRP. At this time, the regional resource adequacy program has not been contemplated or included in the analysis described in this chapter.

In the past, relying on short-term wholesale energy markets has been a very cost-effective strategy for customers. This strategy also avoided building significant amounts of new baseload natural gas generation that might have created significant stranded cost concerns under the new policies. Recent experience shows that while wholesale electricity prices remain low, on average, in the Pacific Northwest (PNW), the region is starting to experience periods of high wholesale electricity prices and low short-term market liquidity.

In addition to the resource adequacy analysis, PSE has a completed a market risk assessment which evaluates the availability of short-term market purchases for peak capacity. It is important that PSE continue to closely monitor the region’s projected winter and summer season load/resource balance and any changes in the liquidity of the short-term market, and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

2. 2021 IRP RESOURCE ADEQUACY ANALYSIS

Resource adequacy planning is used to ensure that all of PSE customer's load obligations are reliably met by building sufficient generating capacity, or acquiring sufficient capacity through contracts, to be able to meet customer demand with appropriate planning margins and operating reserves. The planning margin and operating reserves refer to capacity above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events with minimal interruption of service. Unexpected events can be variations in temperature, hydro and wind generation, equipment failure, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Reliability requires that the full range of potential demand conditions are met even if the potential of experiencing those conditions is relatively low.

The physical characteristics of the electric grid are very complex, so for planning purposes, a 5 percent loss of load probability (LOLP) reliability metric is used to assess the physical resource adequacy risk. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulations. Therefore, the likelihood of capacity being lower than load at any time in the year cannot exceed 5 percent. The 5 percent LOLP is consistent with the resource adequacy metric used by the Northwest Power and Conservation Council (NPCC).

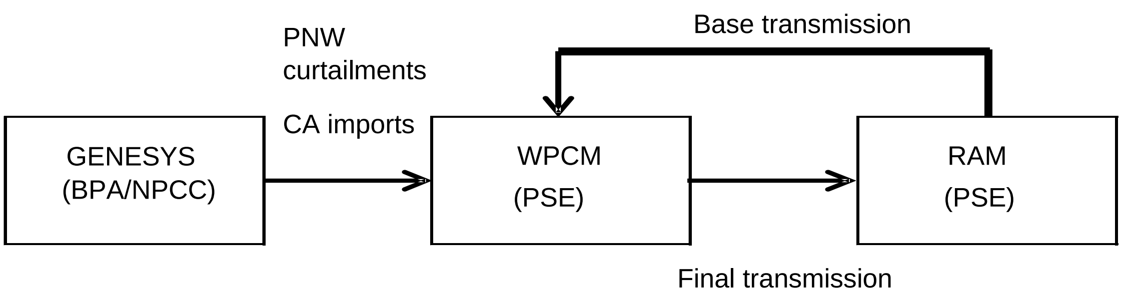
Quantifying the peak capacity contribution of a renewable and energy limited resource (its effective load carrying capacity or ELCC) is an important part of the analysis. The ELCC of a resource represents the peak capacity credit assigned to that resource. It is calculated in the resource adequacy model since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

Resource Adequacy Modeling Approach

PSE's Resource Adequacy Model (RAM) is used to analyze load/resource conditions for PSE's power system. Since PSE relies on significant amounts of wholesale power purchases to meet peak need, the analysis must include evaluation of potential curtailments to regional power supplies. To accomplish this, the RAM integrates two other analyses into its results: 1) the GENESYS model developed by the NPCC and BPA, which analyzes regional level load/resource conditions, and 2) the Wholesale Purchase Curtailment Model (WPCM), developed by PSE, which analyzes the specific effects of regional curtailments on PSE's system. This allows us to evaluate PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

Figure 7-1 illustrates how the inputs and outputs of these models were linked. The outputs of the GENESYS Model provide inputs for both the WPCM model and the RAM/LOLP model. The RAM/LOLP model and WPCM models are used iteratively, with the final output of the RAM/LOLP model used in the next WPCM modelling run.

Figure 7-1: Market Reliability Analysis Modeling Tools



The GENESYS Model

The GENESYS model was developed by the NPCC and the Bonneville Power Administration (BPA) to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions, and as of the 2023 assessment, 88 years of temperature conditions. For the 2021 IRP, PSE started with the GENESYS model from the NPCC power supply adequacy assessment for 2023. When combined with thermal plant forced outages, the mean expected time to repair those units, variable wind plant generation and available imports of power from outside the region, the model determines the PNW's overall hourly capacity surplus or deficit in 7,040 multi-scenario "simulations." Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[1]

1 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the GENESYS model. A PNW load-curtailment event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) utilizing both forward and short-term purchases.

Since the GENESYS model was set for a 2023 assessment, PSE made some updates to capture regional load/resource changes in order to run the model for the years 2027 and 2031. The updates that PSE made to the GENESYS model include:

1. Updated coal plant retirements with retirement years listed in Figure 7-2.

Figure 7-2: Coal Plant Retirements Modeled

Plant	Year Retired in Model
Hardin	2018
Colstrip 1 & 2	2019
Boardman	2020
Centralia 1	2020
N Valmy 1	2021
N Valmy 2	2025
Centralia 2	2025
Jim Bridger 1	2023
Jim Bridger 2	2028
Colstrip 3 & 4	2025

2. Increased the year 2023 demand forecast using the escalation rate of 0.3 percent to the year 2027 and 2031. The escalation rate is from the NPCC demand growth after conservation.
3. Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW).

PSE did not include any other adjustments to GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from NPCC already built into the model.

The Wholesale Purchase Curtailment Model (WPCM)

During a PNW-wide load-curtailment event, there is not enough physical power supply available in the region (including available imports from California) for the utilities of the region to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, PSE developed the WPCM as part of the 2015 IRP. The WPCM links regional events to their specific impacts on PSE's system and on PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

The amount of capacity that other load-serving entities in the region purchase in the wholesale marketplace has a direct impact on the amount of capacity that PSE would be able to purchase. Therefore, the WPCM first assembles load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events. For this analysis, PSE used the capacity data contained in BPA's *2018 Pacific Northwest Loads and Resources Study*, the latest BPA study available at the time this resource adequacy analysis was completed. Due to the pandemic, BPA's 2019 study was delayed and not available for this analysis.

BPA Loads and Resources Study for 2020–2029

BPA published its *2018 Pacific Northwest Loads and Resources Study* in April 2019. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region.

The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads.

- For 2023, the BPA study forecasts an overall regional winter peak load deficiency of 3,056 MW.
- When BPA's 2023 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 3,056 MW capacity deficit noted above would change to a 344 MW surplus.
- Looking forward to 2029 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2020 winter season peak load deficit of approximately 246 MW to a peak load deficit of approximately 4,891 MW in 2029.
- When BPA's 2029 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in its RAM – the region would transition from a 2020 winter capacity surplus of 3,054 MW to a peak load deficit of approximately 1,491 MW by 2029.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2023. The BPA forecast indicates, as does the Pacific Northwest Utilities Conference Committee (PNUCC) study, that the PNW may experience larger winter capacity deficits over time.

> > > BPA's *2018 Pacific Northwest Loads and Resources Study* can be found at: https://www.bpa.gov/p/Generation/White-Book/wb/2018-WBK-Loads-and-Resources-Summary-20190403.pdf

In October 2020, BPA published its *2019 Pacific Northwest Loads and Resources Study*. The study was completed after PSE finalized this resource adequacy analysis, so updated 2019 information could not be incorporated. PSE is reviewing the 2019 BPA study to assess its implications for the analysis.

Allocation Methodology

The WPCM then uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases. In essence, on an hourly basis, the WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases. In some cases, reductions in PSE's initial desired volume of wholesale market purchases could trigger a load-curtailment event in the LOLP portion of RAM.

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.

SPOT MARKET ALLOCATIONS. For spot market capacity allocation, each of the five large utility purchasers is assumed to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation *is not* based on a straight pro-rata allocation, because in actual operations the largest purchaser (which is usually PSE) would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs but the larger purchasers cannot.

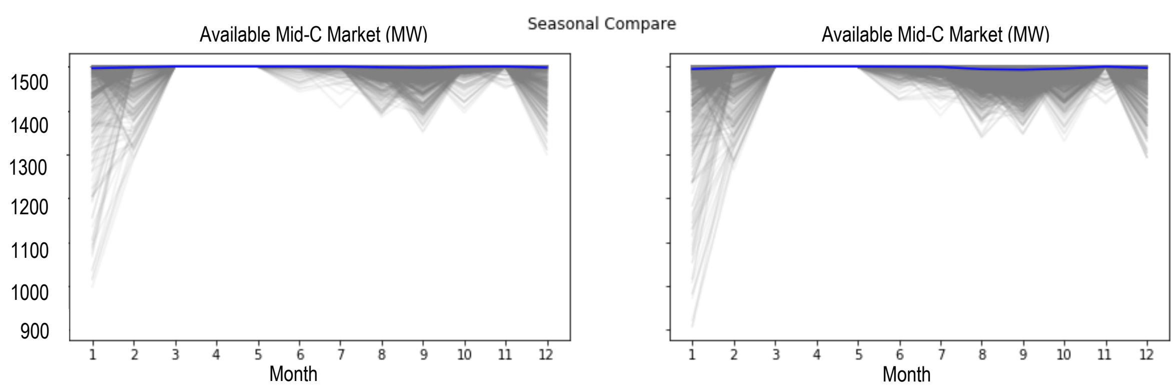
WPCM Outputs

For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-Columbia (Mid-C) transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.

Figure 7-3 shows the results of the WPCM. The charts illustrate the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 7-3: Reduction to Available Mid-C Market



In addition to the WPCM results that are included in PSE's resource adequacy analysis, PSE also conducted a separate market risk assessment. That assessment is described later in this chapter.

The Resource Adequacy Model (RAM)

PSE's probabilistic Resource Adequacy Model enables PSE to assess the following.

1. To quantify physical supply risks as PSE's portfolio of loads and resources evolves over time
2. To establish peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin
3. To quantify the peak capacity contribution of a renewable and energy-limited resource (its effective load carrying capacity, or ELCC)

The RAM allows for the calculation of the following risk metrics.

- **Loss of load probability (LOLP)**, which measures the *likelihood of a load curtailment event occurring* in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s).
- **Expected unserved energy (EUE)**, which measures outage magnitude in MWh and is the *sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations.*
- **Loss of load hours (LOLH)**, which measures outage duration and is *the sum of the hours with load curtailments divided by the number of simulations*.
- **Loss of load expectation (LOLE)**, which measures the *average number of days per year with loss of load* due to system load exceeding available generating capacity.
- **Loss of load events (LOLEV)**, which measures the *average number of loss of load events per year*, of any duration or magnitude, due to system load exceeding available generating capacity.

Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these five risk metrics, once a planning standard has been established.

3. CONSISTENCY WITH REGIONAL RESOURCE ADEQUACY ASSESSMENTS

PSE's reliance on market purchases requires that our resource adequacy modeling also reflect regional adequacy conditions, so consistency with the NPCC's regional GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM.

PSE's RAM operates much like the GENESYS model. Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 7,040 individual simulations; the result of each simulation is PSE's hourly capacity surplus or deficiency. The LOLP, EUE and LOLH for the PSE system are then computed across the 7,040 simulations.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 7,040 simulations made in the NPCC's GENESYS model in terms of temperature and hydro conditions.

The existing resources used by PSE included in this analysis are Mid-Columbia purchase contracts and western Washington hydroelectric resources, several natural gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. Since Colstrip must be out of PSE's portfolio by 2026, it was assumed to retire on 12/31/2025 and was not included as a resource in either GENESYS or RAM.

The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

1. **FORCED OUTAGE RATE FOR THERMAL UNITS**. Forced outage refers to a generator failure event, including the time required to complete the repair. The "Frequency Duration" outage method in AURORA is used to model unplanned outages (forced outage) for thermal plants. The Frequency Duration outage method allows units to fail or return to service at any time-step within the simulation, not just at the beginning of a month or a day. The method will employ all or nothing outages for most outages but will use partial outages at the beginning and end of the outage period. The logic considers each unit's forced outage rate and mean repair time. When the unit has a planned maintenance schedule, the model will ignore those hours in the random outage scheduling. In other words, the hours that planned maintenance occurs is not included in the forced outage rate.

2. **HOURLY SYSTEM LOADS**. Hourly system loads are modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 88 temperature years. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2016 is represented in the 88 demand draws. Since the resource adequacy model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. Additionally, the model examines adequacy in each hour of a given future year; therefore, the model inputs are scaled to hourly demand using the hourly demand model.

3. **MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 7,040 combinations of hydro and temperature simulations are consistent with the GENESYS model.

4. **WHOLESALE MARKET PURCHASES.** These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained above. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM. The initial set of hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights is computed as the difference between

PSE's maximum import rights less the amount of transmission capability required to import generation from PSE's Wild Horse wind plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports was reduced on the hours when a PNW load-curtailment event is identified in the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

5. **WIND AND SOLAR.** PSE models 250 unique 8,760 hourly profiles, which exhibit the typical wind generation patterns. Since wind and solar are both intermittent resources, one of the goals in developing the generation profile for each wind and solar project considered is to ensure that this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind and solar generation are reflected. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL's) Wind Tool Kit database.[2] Wind speed data was collected from numerous sites within a prescribed radius around a region of interest. Wind speed data was processed with a heuristic wind production model to generate hundreds of possible generation profiles. The 250 profiles which aligned most closely with the average seasonal production of the site, as determined by the average of the entire data set, were selected for use in the RAM. The profiles were then correlated by measurement year. Similarly, solar irradiance data for a given region was obtained from the National Solar Radiation Database[3] and processed with the NREL System Advisory Model to generate production profiles. The 250 solar profiles which were most closely aligned with the annual average production, as determined by the annual average of the entire data set, were selected for use in the RAM. The solar profiles were correlated by measurement year.

Construction risk is not directly incorporated in the resource adequacy model. Permitting and construction times are accounted for in the first year that a new resource is available. For example, if a resource takes four years for permitting and construction, and the IRP planning horizon starts in 2022, the new resource would be available in the year 2026. A full discussion of construction and permitting lead times is available in Appendix D.

2 / https://www.nrel.gov/grid/wind-toolkit.html
3 / https://nsrdb.nrel.gov/

4. OPERATING RESERVES AND PLANNING MARGIN

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 (NWPP), 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 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).

In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60 minutes, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power or curtailing load. The RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, should a forced outage at one of PSE's generating plants cause loads to exceed available resources.

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 are resources that have the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts versus real-time values for load, wind and solar generation. The first study was for the year 2025 and includes PSE's current portfolio plus new renewable resources. The second study is for the year 2030 and includes PSE's current portfolio plus generic wind and solar resources to meet the 80 percent renewable requirement. Figure 7-4 below is a summary of the flex up and flex down requirement given the renewable resources that PSE will balance. By 2030, PSE's balancing reserve requirements will significantly increase with the large increase in intermittent renewable resources. The increase in balancing reserves will increase the need for flexible capacity resources. This analysis was based on the results from the 2019 IRP Process, where PSE estimated that it will balance almost 2,400 MW of wind and 1,400 MW of solar by 2030 to meet CETA goals. These results are in alignment with the 2021 IRP process.

Figure 7-4: Balancing Reserve Requirements

Case	Capacity of PSE-balanced Wind (MW)	Capacity of PSE-balanced solar (MW)	Average Annual Flex up (MW)	Average Annual Flex down (MW)	99th percentile of forecast error (flex up cap)	1st percentile of forecast error (flex down cap)
2025 Case	875	-	141	146	190	196
2030 Case	2,375	1,400	492	503	695	749

This table is a summary of the flexible ramp requirements. RAM uses for the hourly flex up and flex down requirements for each study year.

Planning Margin

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin is defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of reliable service to customers under peak load conditions. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

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

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

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

In this IRP, PSE continues to utilize the LOLP metric to determine its capacity planning margin and establishes the 5 percent LOLP level used by the NPCC as adequate for the region. This value is obtained by running the 7,040 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using "perfect" capacity, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

5. 2021 IRP RAM INPUT UPDATES

The following key updates to the RAM inputs were made since the 2019 IRP Progress Report:

1. The load forecast was updated to reflect the 2021 IRP demand forecast assumptions.
2. The hourly draws of the existing PSE wind fleet and new wind resources were based on NREL wind data set of 250 stochastic simulations.
3. The hourly draws of existing PSE solar resources and new solar resources were based on NREL solar data set of 250 stochastic simulations.
4. Colstrip Units 3 & 4 and Centralia were removed.
5. New resources from the 2018 RFP were added.
6. The balancing reserve requirements were updated to include new results for study years 2025 and 2030.

YEARS MODELED. The 2021 IRP time horizon starts in 2022, so PSE modeled a 5-year and 10-year resource adequacy assessment. The first assessment is the 5-year assessment for the period of October 2027 – September 2028. The second assessment is the 10-year assessment for the period of October 2031 – September 2032. The modeled year follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact for the analysis. This is consistent with the NPCC's GENESYS model. If PSE modeled the calendar year, it would break up the winter season (November – February).

PSE also updated the 2023 forecasts from the 2018 NPCC Resource Adequacy Assessment in the RAM model. Since PSE is modeling the years 2027 and 2031, the GENESYS model was updated from the year 2023 to match the years 2027 and 2031. This was done by updating the demand forecast using the Council's demand escalation, updating plant retirements such as Colstrip and Centralia, and including new resources from PSE's portfolio (Skookumchuck and Lund Hill). The detailed updates were discussed earlier in this chapter.

RAM is an annual model. It is run for all hours of the year studied. All of the loss of load events are then added up for the year and accounted for in the annual modeling process. The model is set up to track annual events to a planning margin that is applied at the system peak. Monthly or seasonal RAM metrics are not available for this IRP but are being considered for the next IRP.

Study Year 2027

The incremental impact of each modeling update on the capacity need for the study year 2027 is documented in Figure 7-5. The starting point is the 2019 IRP Process capacity need with Colstrip Units 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-5: Impact of Key Input Revisions for 2027

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2027 - Sep 2028
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	1,867
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2027-2028	960	
	Updated balancing reserves for 2025 Case	918	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	982	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP Load Forecast for October 2027 – September 2028		1,334
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,273
	Updated Lund Hill generation to NREL data		1,291
	Add Golden Hills		1,161
	Add new RFP resource		1,018
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		887
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		881
	Fixed correlations for wind and solar data		907

Figure 7-6 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 907 MW of perfect capacity is needed in the year 2027 to meet the 5 percent LOLP.

Figure 7-6: Reliability Metrics at 5% LOLP for 2027

Metric	Base System – no added resources	System at 5% LOLP – add 907 MW
LOLP	68.84%	4.99%
EUE	5,059 MWh	430 MWh
LOLH	11.06 hours/year	0.83 hours/year
LOLE	12.58 days/year	0.12 days/year
LOLEV	2.49 events/year	0.14 events/year

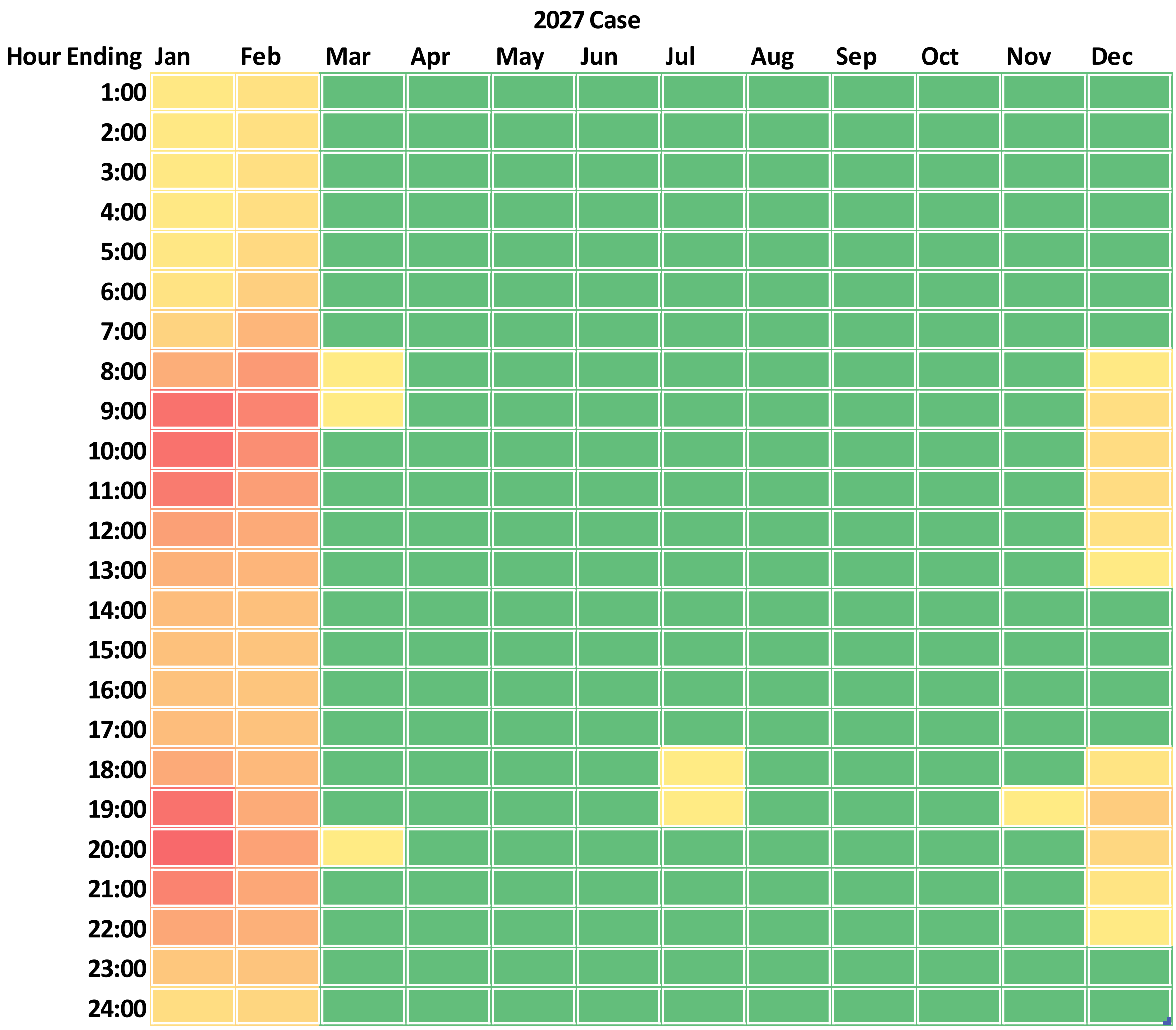
A loss of load event can be caused by many factors, which may include temperature, demand, hydro conditions, plant forced outages and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. Figure 7-7 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February. However, this is the first time that we are seeing events occur in the summer, even though they affect few hours (about 0.04 percent of total hours). Given this result, PSE is still strongly winter peaking; we do not see this changing but will continue to monitor the summer events.

Figure 7-7: Hours of Loss of Load across 7,040 Simulations for 2027

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	4,846	2,893
2	3,296	2,553
3	10	5
4	-	-
5	-	-
6	10	-
7	3	2
8	-	-
9	-	-
10	-	-
11	5	1
12	474	275

Figure 7-8 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-8: Loss of Load Hours for 2027



Study Year 2031

The incremental impact of each modeling update on the capacity need for the study year 2031 is documented in Figure 7-9. The starting point is the 2019 IRP Process capacity need with Colstrip 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-9: Impact of Key Input Revisions for 2031

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2031 - Sep 2032
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	2,217
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2031-2032	956	
	Updated balancing reserves for 2030 case	1,071	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	1,134	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP demand forecast for October 2027 – September 2028		1,635
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,581
	Updated Lund Hill generation to NREL data		1,596
	Add Golden Hills		1,469
	Add new RFP resource		1,326
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		1,344
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		1,361
	Fixed correlations for wind and solar data		1,381

Figure 7-10 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 1,361 MW of perfect capacity is needed in the year 2031 to meet the 5 percent LOLP.

Figure 7-10: Reliability Metrics at 5% LOLP for 2031

Metric	Base System – no added resources	System at 5% LOLP – add 1361 MW
LOLP	98.45%	5.00%
EUE	19,243 MWh	419 MWh
LOLH	51.90 hours/year	0.86 hours/year
LOLE	11.25 days/year	0.12 days/year
LOLEV	13.80 events/year	0.17 events/year

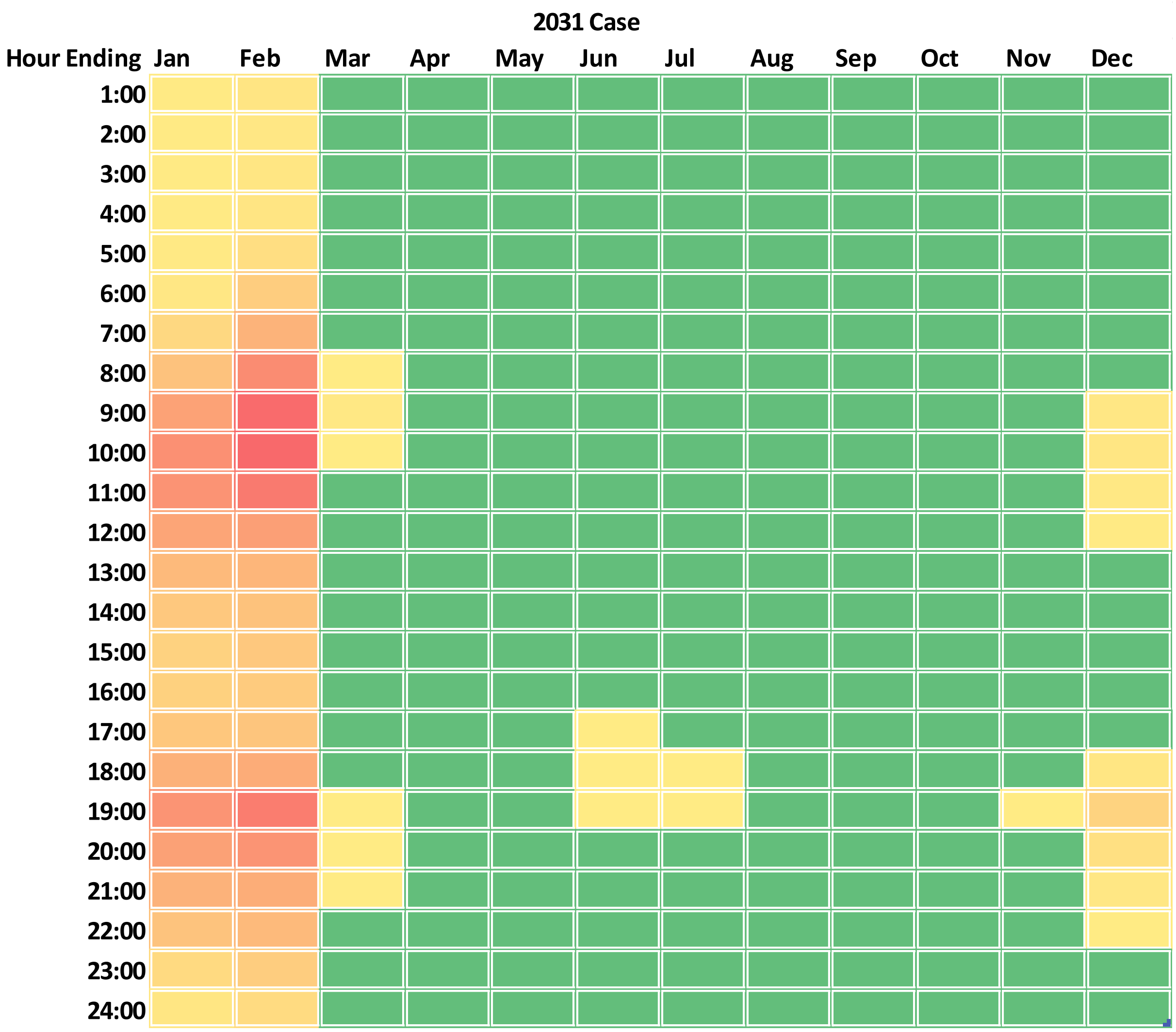
Figure 7-11 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February.

Figure 7-11: Hours of Loss of Load across 7,040 Simulations for 2031

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	3,860	2,387
2	4,267	3,365
3	40	14
4	-	-
5	-	-
6	12	5
7	4	2
8	4	-
9	-	-
10	-	-
11	9	1
12	325	160

Figure 7-12 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-12: Loss of Load Hours for 2031



6. RESOURCE NEED

Planning Margin Calculation

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. Using the LOLP methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031. The planning margin is used as an input into the AURORA portfolio capacity expansion model. It is simply a calculation used as an input into the model to make sure that the expansion model targets 907 MW of new capacity in the year 2027 and 1,381 MW in the year 2031. The planning margin calculation for the 2021 IRP is summarized in Figure 7-13. The Total Resources Peak Capacity Contribution is the combined peak capacity contribution of all the existing resources in PSE's portfolio and is also referred to as the effective load carrying capability (ELCC). The peak capacity contribution of planned future resources is described later in this chapter.

Figure 7-13: 2021 IRP Planning Margin Calculation

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	907 MW	1,381 MW
Total Resources Peak Capacity Contribution	3,591 MW	3,599 MW
Short-term Market Purchases	1,471 MW	1,473 MW
Generation Capacity	5,969 MW	6,453 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.7%**	**24.2%**

The total peak capacity contribution of existing and new resources has been updated based on the 2021 IRP ELCC calculation.

Peak Capacity Credit of Resources

The effective load carrying capability (ELCC) of a resource represents the peak capacity credit assigned to that resource. It is calculated in RAM since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of perfect capacity that would yield the same level of reliability. For resources such as a wind, solar, or other energy-limited resources such as batteries and demand response programs, the ELCC is expressed as a percentage of the equivalent perfect capacity. Since the

ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

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

HYDRO RESOURCES CAPACITY CREDITS. The estimated peak contribution of hydro resources was modeled in the RAM. We only modeled the ELCC of PSE owned hydro, Baker River Projects and Snoqualmie Falls. The peak capacity contribution of the Mid-C hydro is based on the Pacific Northwest Coordination Agreement (PNCA) final regulation and represents PSE's contractual capacity less losses, encroachment and Canadian Entitlement.

Figure 7-14: Peak Capacity Credit for Hydro Resources Based on 5% LOLP Relative to Perfect Capacity

Hydro Resources	ELCC Year 2027 (MW)	ELCC Year 2031 (MW)
Upper Baker Units 1 and 2	90	90
Lower Baker Units 3 and 4	82	79
Snoqualmie Falls	38	37

Figure 7-15: Peak Capacity Credit for Mid-C Hydro Resources
Based on Contractual Capacity Less Losses, Encroachment and Canadian Entitlement

Hydro Resources	Peak Capacity Credit Year 2027 (MW)	Peak Capacity Credit Year 2031 (MW)
Priest Rapids	5	5
Rock Island	121.2	121.2
Rocky Reach	313	313
Wanapum	6.1	6.1
Wells	115	115

THERMAL (NATURAL GAS) RESOURCES CAPACITY CREDITS. The peak capacity contribution of natural gas resources is different than other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need is at 23 degrees Fahrenheit, the capacity of natural gas plants is set to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. The forced outage of natural gas resources is accounted for in the variability of the 7,040 simulations. As mentioned in the "consistency with regional resource adequacy assessments" section above, PSE uses the "Frequency Duration" outage method in AURORA to simulate unplanned outages (forced outage) for thermal plants. The forced outage is already incorporated into the 907 MW capacity need.

Figure 7-16: Peak Capacity Credit for Natural Gas Resources

THERMAL RESOURCES	Peak Capacity Credit based on 23 degrees (MW)
Sumas	137
Encogen	182
Ferndale	266
Goldendale	315
Mint Farm	320
Frederickson CC	134
Whitehorn 2 & 3	168
Frederickson 1 & 2	168
Fredonia 1 & 2	234
Fredonia 3 & 4	126
Generic 1x0 F-Class Dual Fuel Combustion Turbine	237
Generic 1x1 F-Class Combined Cycle	367
Generic 12x0 18 MW Class RICE	219

WIND AND SOLAR CAPACITY CREDITS. In order to implement the ELCC approach for wind and solar in the RAM, the wind and solar projects were added into the RAM incrementally to determine the reduction in the plant's peaking capacity needed to achieve the 5 percent LOLP level. The wind project's peak capacity credit is the ratio of the change in perfect capacity with and without the incremental wind capacity. The order in which the existing and prospective wind projects were added in the model follows the timeline of when these wind projects were acquired or about to be acquired by PSE: 1) Hopkins Ridge Wind, 2) Wild Horse Wind, 3) Klondike Wind, 4) Lower Snake River Wind, 5) Skookumchuck Wind, 6) Lund Hill Solar, 7) Golden Hills Wind, 8) New RFP Resource, and finally 9) a generic wind or solar resource. Figure 7-17 below shows the ELCC of the wind and solar resources modeled in this IRP.

Figure 7-17: Peak Capacity Credit for Wind and Solar Resources Based on 5% LOLP Relative to Perfect Capacity

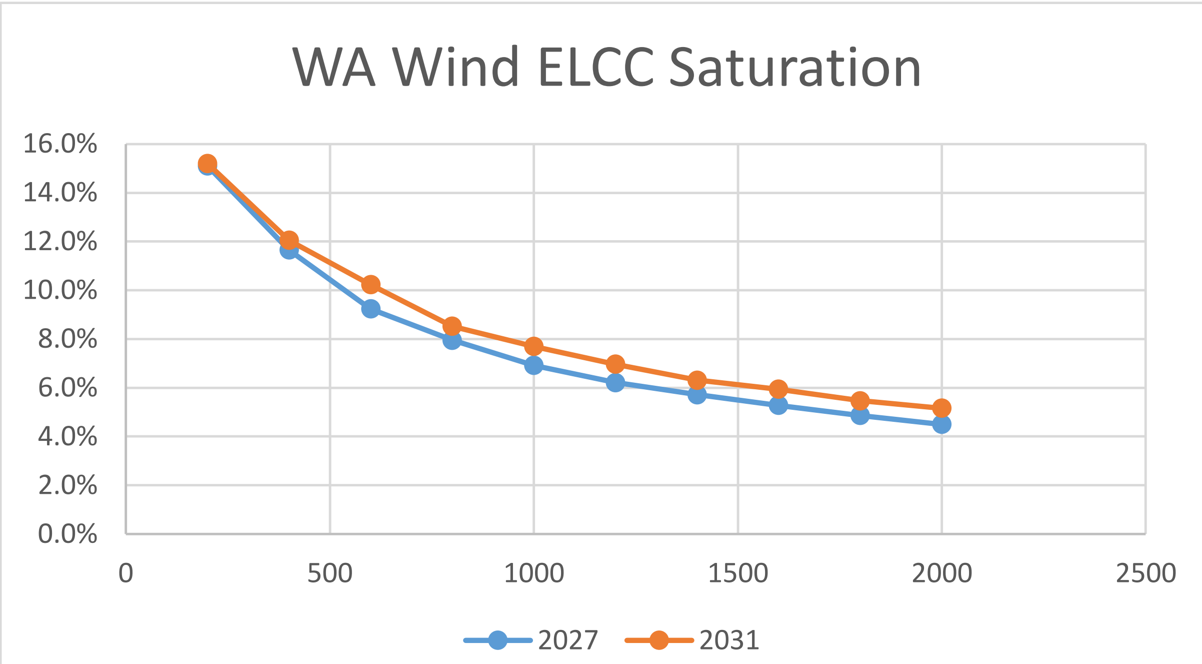
WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar[1]	100	4.0%	3.6%
Generic WA West Solar – Utility-scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

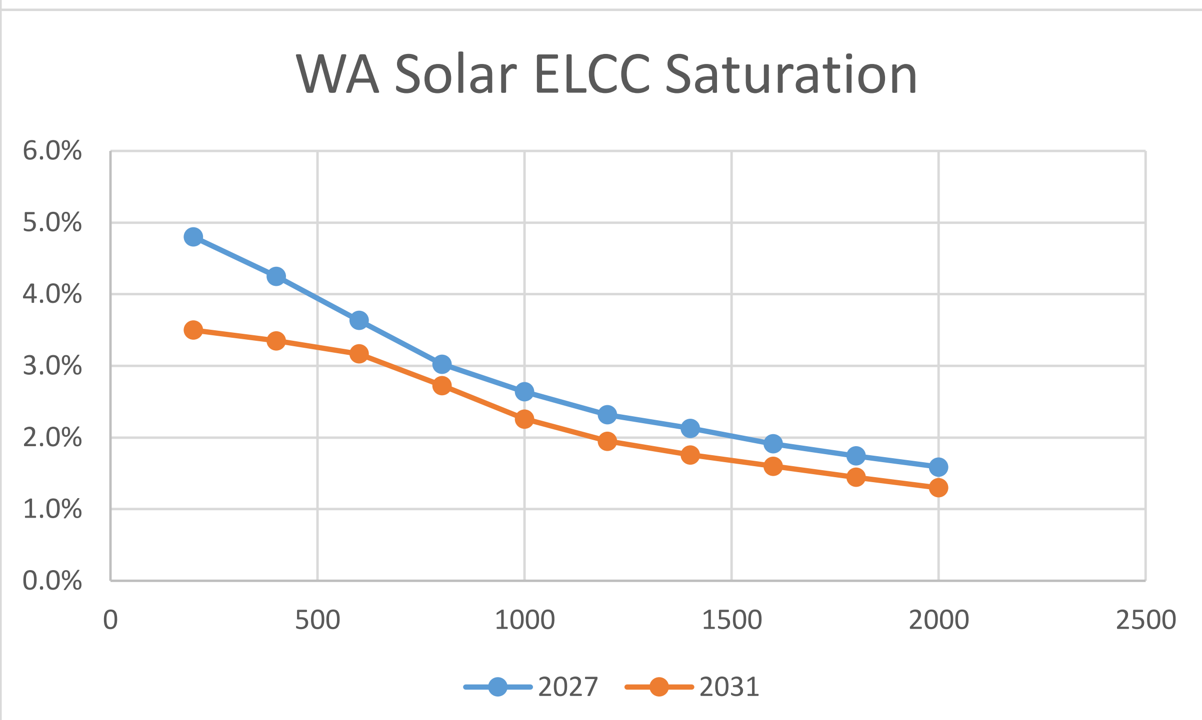
NOTES

1. This ELCC is for the first 100 MW of the resource, the saturation curve for up to 2,000 MW is shown below.

ELCC saturation curves: The peak capacity credit in Figure 7-17 above is for the first 100 MW of installed nameplate capacity for Washington wind and solar. Figure 7-18 below is the ELCC for the next 200 MW and then the next 200 MW after that and so on. The Figure shows a decreasing ELCC as more wind or solar is added to the same region.

Figure 7-18: Saturation Curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty.

As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19.

Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's peak capacity contributions with other entities. Some of the peak capacity contributions are higher and some lower depending on PSE's needs, demand shapes and availability of the supply-side resources. PSE's winter peak makes it different than the parts of the western interconnect that have a summer peak. Summer peaking events are focused in the late afternoon/evening when the day is the hottest and only last a few hours in the evening, which makes energy storage an ideal solution. However, a winter event can last several days at a time and temperatures can drop low during the night and stay low throughout the day. The low peak capacity contribution for energy storage is because these are short duration resources. As shown in Figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events.

Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

HYBRID RESOURCES CAPACITY CREDIT. The capacity contribution of a solar plus battery storage resource is also estimated using EUE. The peak capacity credit of a solar plus battery storage resource is shown in Figure 7-20.

Figure 7-20: Peak Capacity Credit for Hybrid Resource Based on EUE at 5% LOLP

SOLAR + BATTERY RESOURCE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	15.4%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	23.0%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	57.7%

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response program is also estimated using EUE, since this resource is also energy limited like storage resources. The same methodology was used as for storage resources. The peak capacity contribution of demand response is shown in Figure 7-21.

Figure 7-21: Peak Capacity Credit for Demand Response

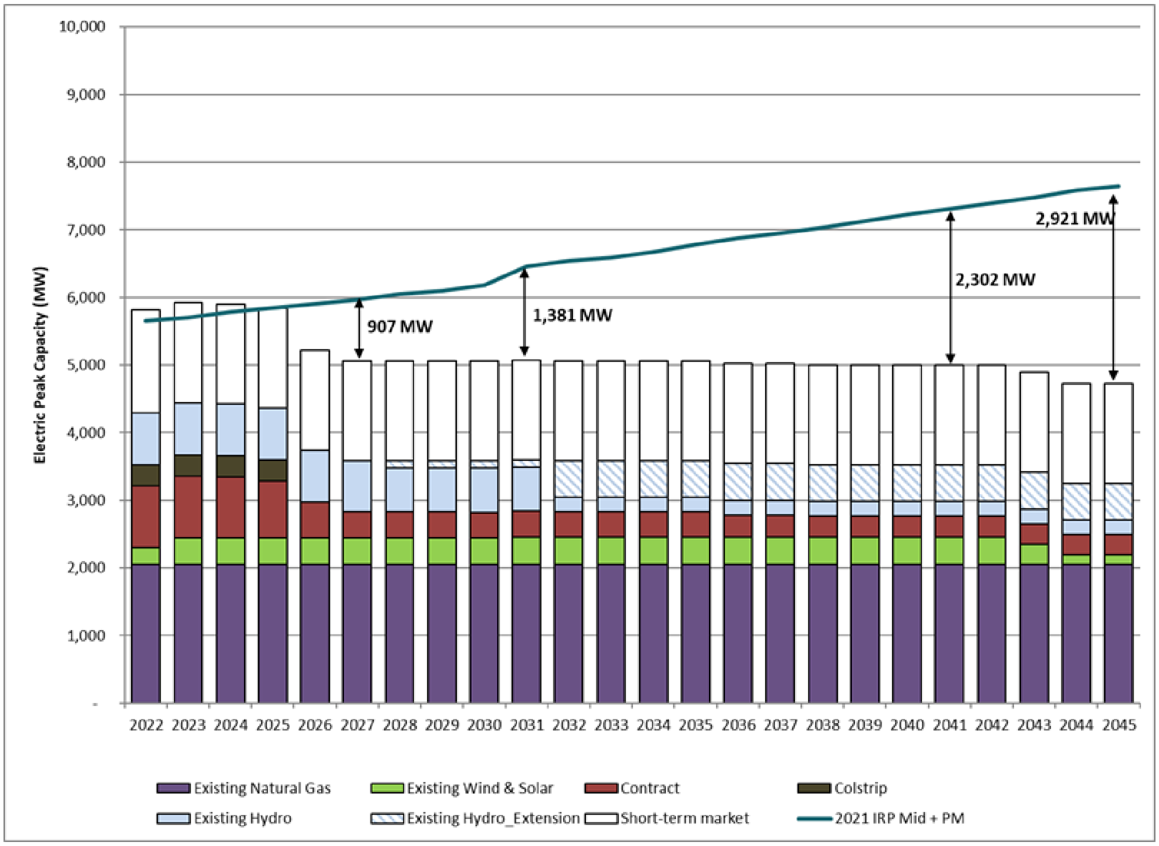
DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Peak Capacity Need

Figure 7-22 shows the peak capacity need for the mid demand forecast modeled in this IRP. Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW by 2027 and 1,381 MW in 2031 (represented by the teal line in Figure 7-22). This includes a 20.7 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE’s 5 percent LOLP planning standard. The graph shows a noticeable drop in PSE’s resource stack at the end of 2025. The drop is caused by the elimination of Colstrip 3 & 4 from PSE’s energy supply portfolio starting in 2026, which removes approximately 370 MW of capacity, and the expiration of PSE’s 380 MW coal-transition contract with TransAlta when the Centralia coal plant is retired at the end of 2025.

The peak capacity deficit assumes that 1,500 MW of market purchases is available to meet peak capacity need. Further analysis of market risk is described below.

Figure 7-22: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



7. ALTERNATIVE FUEL NEED FOR RESOURCE ADEQUACY

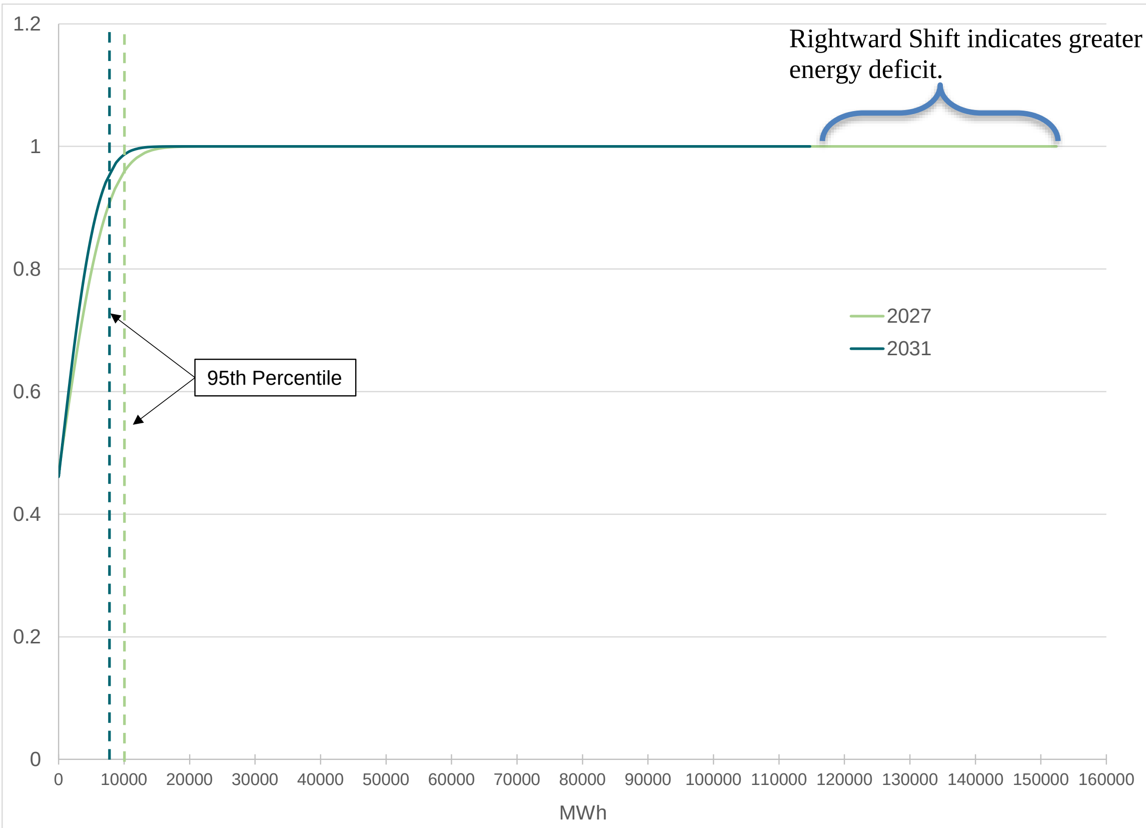
As part of the 2021 IRP, PSE tested CETA-compliant alternative fuels for peakers. When analyzing alternative fuels such as biodiesel, two key issues arise:

1. How many hour many run hours are needed for the year in order to maintain resource adequacy?
2. Is there enough fuel supply?

Incremental outages are examined, using RAM, for loss of load events and hours of outages. Because RAM is a stochastic model performing analysis over 7,040 draws, both the MWh outages and hours of outages are presented as a cumulative distribution.

Figure 7-32 shows the cumulative distribution of generation (MWh) resulting from the incremental outage events for model years 2027 and 2031. This sensitivity was run by removing the peakers form the portfolio and determining how much generation is needed to maintain resource adequacy. The higher the level of capacity that is unable to run due to the lack of peaker generation, the greater the amount of deficit. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the 95th percentile of generation that the peakers are needed to maintain resource adequacy.

Figure 7-32: Cumulative Distribution of Incremental Deficit for Loss of Load Events for All Simulations in MWh/yr



In 95 percent of simulations, to maintain resource adequacy, the peakers are needed to run for 10,000 MWh or less, which is around 15 hours of run time, and the maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[4] on biofuel production, the total annual production of biodiesel in Washington state is 114 MM gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel or about 0.7 percent of Washington State's annual production.

4 / https://www.eia.gov/biofuels/biodiesel/production/

8. MARKET RISK ASSESSMENT

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases under the WSPP contract schedule C,[5] where physical energy can be sourced in the day-ahead or the real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and ensuing procurement. For this IRP, PSE conducted a market risk assessment to evaluate the 1,500 MW assumption in addition to the evaluation completed with the WPCM.

The market risk assessment results in a proposal to increase firm resource adequacy qualifying capacity contracts while limiting the amount of real-time, day-ahead and term market purchases from 1,500 MW to 500 MW by the year 2027 to satisfy peak capacity needs. Support for such a reduction is based on changing market fundamentals in the Western Electricity Coordinating Council (WECC) that impact PSE's ability to access firm market purchases to meet demand. A reduction from 1,500 MW to 500 MW by 2027 provides a realistic and feasible path towards firm capacity for long-term peak capacity planning. The reduction in market purchases used in IRP planning is supported by the reduced capacity and liquidity in the region, coupled with increased volatility at the Mid-C market hub. The events of August 2020 underscore the need to change the IRP planning assumptions; in that event, PSE and other entities were not able to procure additional supply from the market.

Changing WECC Supply/Demand Fundamentals

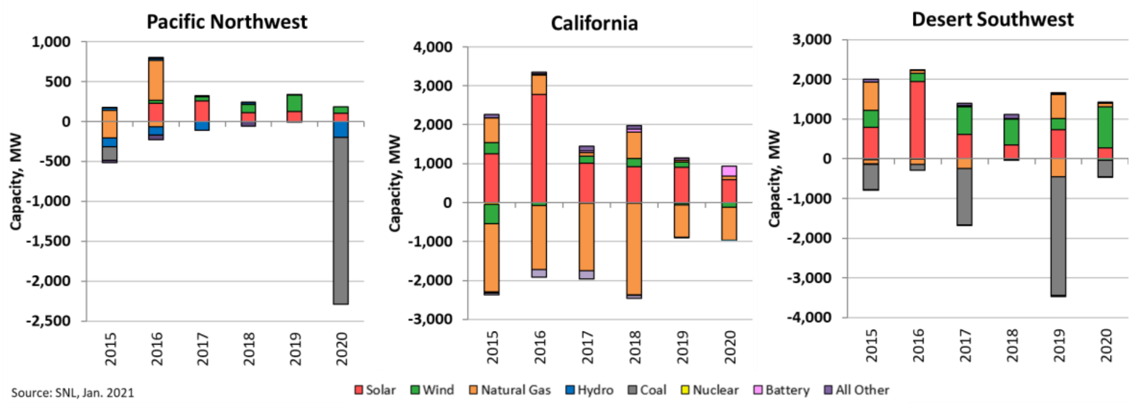
Generating Capacity Changes

Power market supply/demand fundamentals have changed significantly in recent years. As customers, corporations and state legislatures across the Western Interconnection prefer or require power from clean energy sources, intermittent energy sources – namely wind and solar – have been built while traditional dispatchable capacity resources have been retired or mothballed. The growing capacity deficit in the region has been well documented in several recent studies.[6] Since 2016, nearly 15,000 MW of clean capacity and 500 MW of batteries have been added to

5 / https://www.wspp.org/pages/Agreement.aspx

6 / 2018 Pacific Northwest Loads and Resources Study (White book) (BPA, 2020); Resource Adequacy in the Pacific Northwest (E3, 2019); 2018 Long-Term Reliability Assessment (North American Reliability Corporation and Western Electricity Council, 2018); Pacific Northwest Power Supply Adequacy Assessment for 2023 (Northwest Power and Conservation Council, 2018); Northwest Regional Forecast of Power Loads and Resources: 2020 through 2029 (Pacific Northwest Utilities Conference Committee, 2019); Long Term Assessment of the Load Resource Balance in the Pacific Northwest (Portland Gas and Electric and E3, 2019) the grid while 12,000 MW of coal and natural gas resources have been retired, as illustrated in Figure 7-23.

Figure 7-23: Capacity Additions and Retirements Since 2016

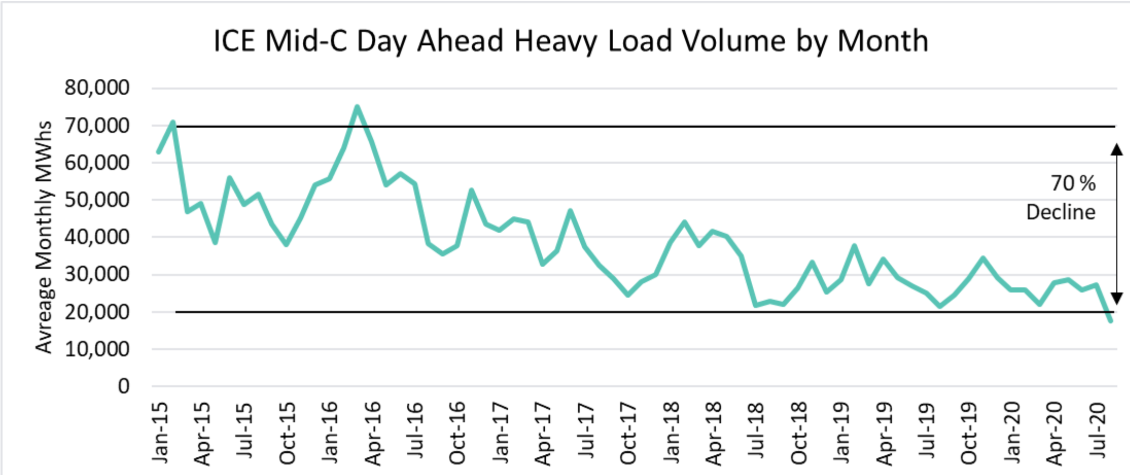


Included in Pacific Northwest thermal retirements are the retirements of Colstrip 1 and 2 in January 2020, which increased PSE's reliance on the short-term market by 300 MW. With less dispatchable generation capacity within the WECC, market supply/demand fundamentals have tightened.

Transaction Volumes and Volatility

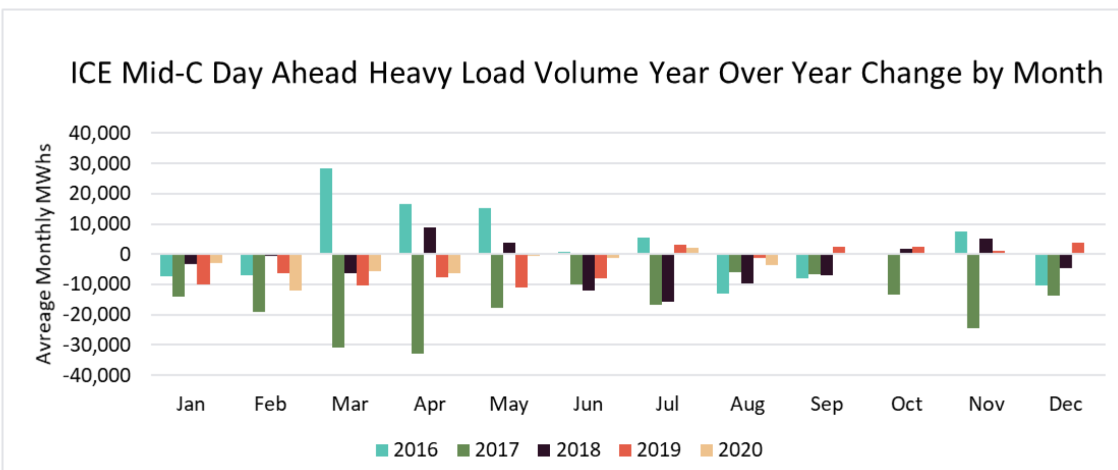
Reductions in traded volume in the day-ahead market also indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available which market participants can trade. This also is suggestive of energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 7-24 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 7-24: Mid-C Day-ahead Heavy Load Volume Timeline



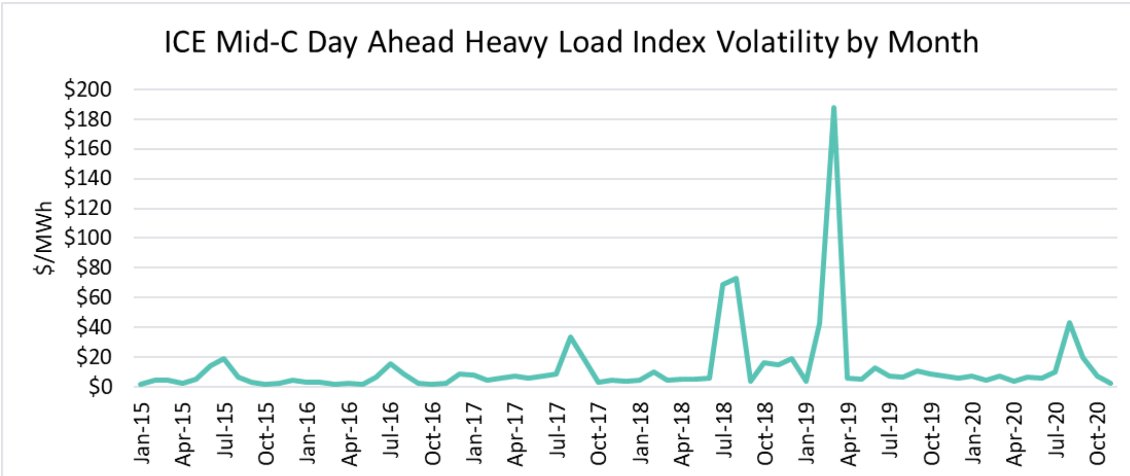
The decline has been consistent in all delivery periods. Figure 7-25 shows the average monthly change in trading volume from one year to the next. Negative bars show a reduction in trading volume while positive bars show an increase in trading volume.

Figure 7-25: Mid-C Day-ahead Heavy Load Volume Monthly Change



Additionally, price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018 when high regional temperatures coincided with forced outages at Colstrip; in March 2019 when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020 during a west-wide heat event. The volatility of day-ahead heavy load prices is presented in Figure 7-26.

Figure 7-26: Volatility of Heavy Load Mid-C Day-ahead Prices



Approach of Regional Investor Owned Utilities

Coinciding with the retirement of legacy baseload capacity and the decline of market liquidity, several regional investor owned utilities (IOUs) have reduced their assumptions of available market capacity in their IRPs. A lack of reliance or a reduced reliance on the market for capacity has precedent as shown in Figure 7-27. While it is difficult to get an exact comparison since IOUs have different resource planning assumptions, hedging and procurement practices, it is clear that PSE's market purchases are higher than other IOUs.

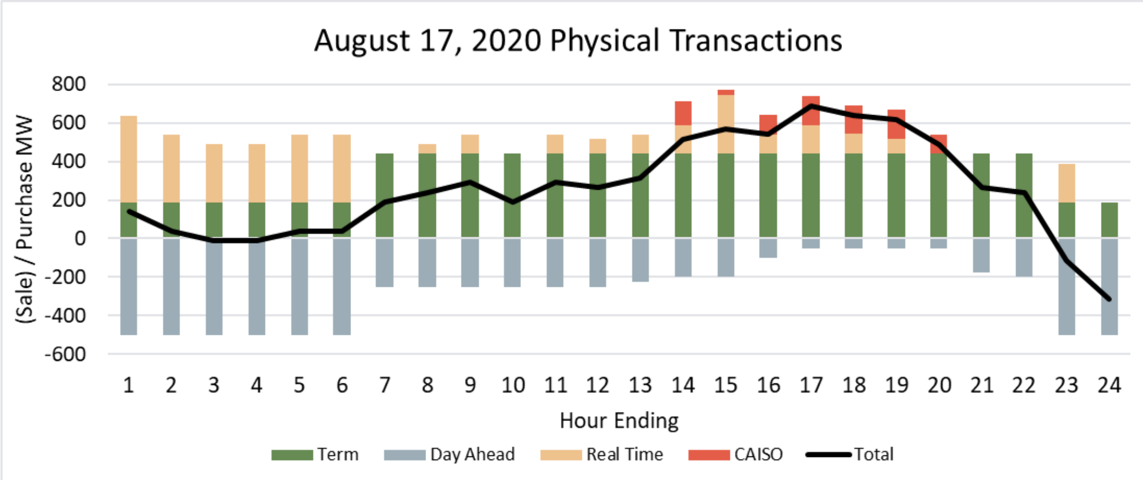
Figure 7-27: Regional IOU Market Reliance

Entity	Planned Summer Market Reliance Limit (MW)	Planned Winter Market Reliance Limit (MW)	Commentary
Avista	330	330	From the draft 2021 IRP. Market purchases are limited to 500 MW during 'unconstrained' hours, and 330 MW during 'constrained' hours
Idaho Power	N/A	N/A	The current IRP (2019) assumes market purchases of 500 MW in the summer and 425 MW in the winter. Specific market purchase limits are not defined in the IRP.
PacifiCorp	500 – Aggregate 150 – Mid-C Seasonal HLH	1000 – Aggregate 0 – Mid-C Seasonal HLH	Proposed Front Office Transaction Limits for the 2021 IRP cycle.
Portland General	50	0	Estimates from *Long Term Assessment of the Load Resource Balance in the Pacific Northwest* (Portland Gas and Electric and E3, 2019)
Puget Sound Energy	1,500	1,500	PSE counts historical energy offers at the Mid-C hub as available capacity to meet peak demand needs in the winter and summer.

Events of August 2020

Amid a west-wide heat wave lasting from August 14, 2020 to August 19, 2020, several balancing authority areas (BAAs) in the Western Interconnect declared various stages of energy emergency. This included the CAISO, which declared a stage 3 emergency and cut firm load on August 14 and 15. PSE's BAA declared a stage 1 emergency on August 17, 2020 as there was concern about the ability to procure capacity to meet load and contingency reserve obligations during hours ending 15 – 18 (3pm – 6pm). PSE's BAA ultimately did not progress further into emergency conditions and all load and contingency reserves were met. PSE ultimately relied on 400-505 MW of market purchases using WSPP-C contracts and 25 to 150 MW of exports from the CAISO, but could not procure additional capacity. This was significantly less than the 1,500 MW of market purchases that has been assumed to be available to meet demand in PSE's IRP. PSE's total market reliance on August 17, 2020 is shown in Figure 7-28. The different color bars show when the energy was procured for each hour on the day of August 17, 2020. Limited amount of imports from California were available.

Figure 7-28: Physical Transactions (MW) on August 17, 2020



Peak Capacity Need

ADJUSTED PEAK CAPACITY NEED. The reduction in market purchases to 500 MW increases the peak capacity deficit in 2027 from 907 MW to 1,853 MW. The planning margin calculation for the adjusted peak capacity need is summarized in Figure 7-29.

Figure 7-29: 2021 IRP Planning Margin Calculation with Declining Market Reliance

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	1,853 MW	2,263 MW
Total Resources Peak Capacity Contribution	3,586 MW	3,599 MW
Short-term Market Purchases	500 MW	500 MW
Generation Capacity	5,940 MW	6,362 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.0%**	**22.4%**

Figure 7-30 below shows the annual change in peak deficit for the declining market reliance and converting the short-term energy purchases to firm resource adequacy qualifying capacity contracts. The market availability at peak gradually declines over a 5-year period at 200 MW per year through to the year 2027. The gray area is the total available transmission to the Mid-C market. This position is usually left open to the short term market, but based on market availability, the open position will be reduced to 500 MW by 2027 with the remaining available transmission used for firm resource adequacy qualifying capacity purchases.

Figure 7-30: Short Term Market Purchases converted to Firm Resource Adequacy Qualifying Capacity Contracts

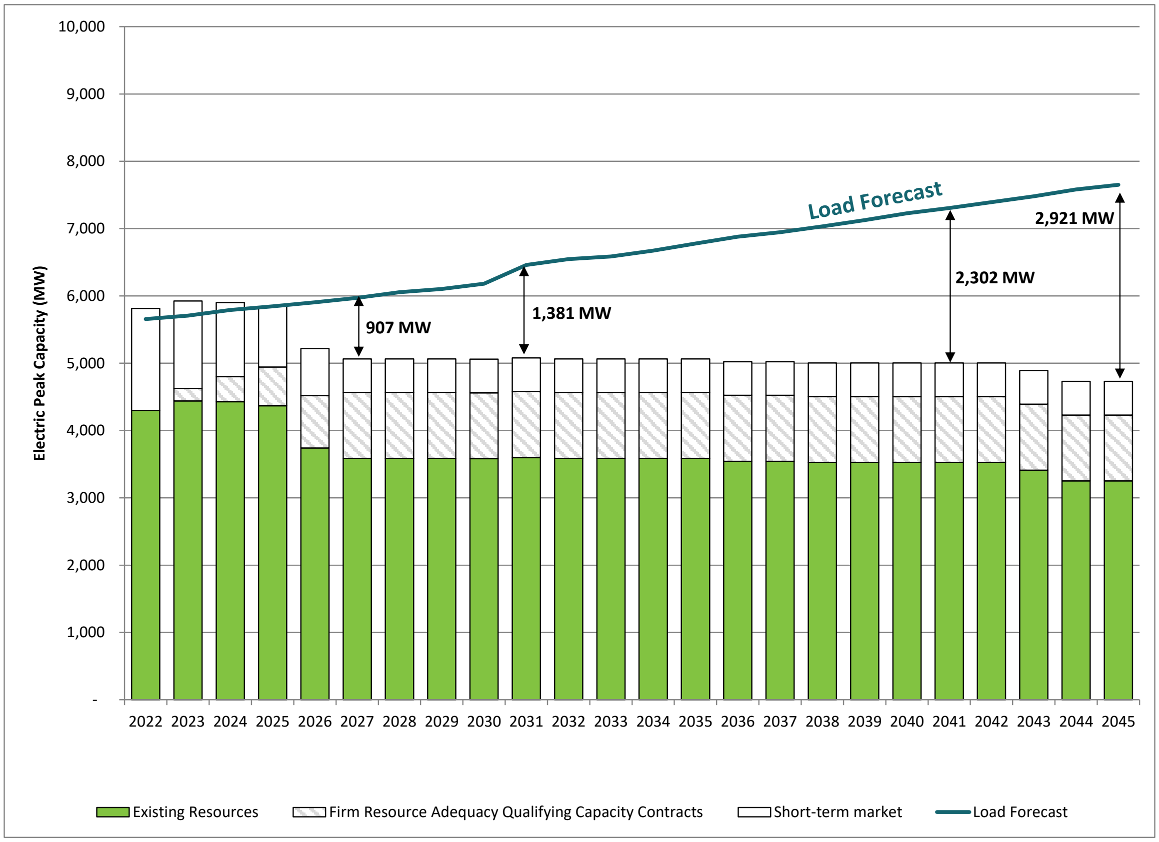
Year	Available Mid-C transmission (MW)	Short Term Market Purchases (MW)	Firm RA Qualifying Capacity Contracts (MW)
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

After 2031, the short term market stays at 500 MW and the firm resource adequacy qualifying capacity contracts at 979 MW.

Figure 7-31 shows the peak capacity need; the grey dashed bars highlight the reduced market purchases described above. Before any additional demand-side resources, peak capacity needed to meet the demand forecast plus planning margin – after reducing market purchases at peak – is 1,853 MW by the year 2027 and 2,263 MW by the year 2031.

Figure 7-31: Electric Peak Capacity Need

(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



9. TEMPERATURE SENSITIVITY

PSE committed to run a future temperature sensitivity as a way to begin to evaluate the impacts of climate change. This sensitivity was for the demand forecast only; PSE did not adjust hydro or wind for the adjusted temperature analysis. PSE relies on the Bonneville Power Administration (BPA) to do hydro modeling, and then PSE receives the data through the Pacific Northwest Coordination Agreement Hydro Regulation. This data has long been used by various organizations to estimate hydro variability. PSE will continue to align with BPA hydro modeling and will analyze any new data as it becomes available to better understand the impacts of climate change to the hydro system. There are three components to the temperature sensitivity analysis:

1. An updated energy demand forecast;
2. An alternative resource adequacy analysis; and
3. A portfolio sensitivity using the Aurora Long Term Capacity Expansion portfolio model.

The energy demand forecast is described in Chapter 6. The resource adequacy analysis adjustments made to account for the alternate temperatures is described below and the results of the portfolio sensitivity can be found in Chapter 8.

The base RAM analysis includes 88 historic temperature years. To create a wider range of possible future temperatures, and consistent with the stakeholder-selected energy demand forecast assumptions, PSE used three models that the NPCC has been using in its resource adequacy analyses. These models (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA) are the product of a recent project by Bonneville Power Administration, U.S. Army Corps of Engineers and the Bureau of Reclamation that down-scaled global climate models to be more specific to the Northwest region. Each of these three models is on the Representative Concentration Pathway of 8.5, which some would argue is a “business as usual” pathway, while others would argue is a more extreme climate warming scenario.

The three models represent different amounts of warming over time. CanESM2_BCSD forecasts 0.9 degree of warming per decade, CCSM4_BCSD forecasts 0.9 degrees of warming per decade, and CNRM-CM5_MACA forecasts 0.5 degrees of warming per decade. While CanESM2_BCSD and CCSM4_BCSD have similar warming trends per decade, the temperatures from the two models are very different from year to year, and CanESM2_BCSD is a full degree warmer than CCSM4_BCSD, on average, over time.

PSE did not change the peak temperature assumptions for this analysis, because while average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Therefore, and as a result, the peak demand forecast did not change.

For each of the three models analyzed, weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RAM run, and weather from 2030 to 2039 was used for the 2031 to 2032 RAM run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model. This mirrors the methodology used in the NPCC resource adequacy analysis.

Using the LOLP methodology with the data from this temperature analysis, it was determined that 328 MW of capacity is needed by the year 2027 and 1,019 MW of capacity by the year 2031. The results of this sensitivity are compared with the base RAM results in Figure 7-32.

Figure 7-32: Peak Capacity Need

	Base	**Temperature Sensitivity**
2027 peak need	907 MW	328 MW
2031 peak need	1,381 MW	1,019 MW

The temperature analysis results showed more loss of load events in the summer caused by inadequate supply while in the base analysis, most loss of load events occurred in the winter season as shown in Figure 7-33. This shift in loss of load events from the winter to summer affects the peak capacity credit of resources. Resources with higher capacities in the summer, such as solar, now have higher peak capacity credit while those with strong winter generation become less effective with a lower peak capacity credit.

Figure 7-33: Frequency of Loss of Load Events by Month and Hour of Day for Model Years 2027 and 2031, Base Scenario and Temperature Sensitivity
(red indicates more loss of load events, green indicates zero loss of load events)

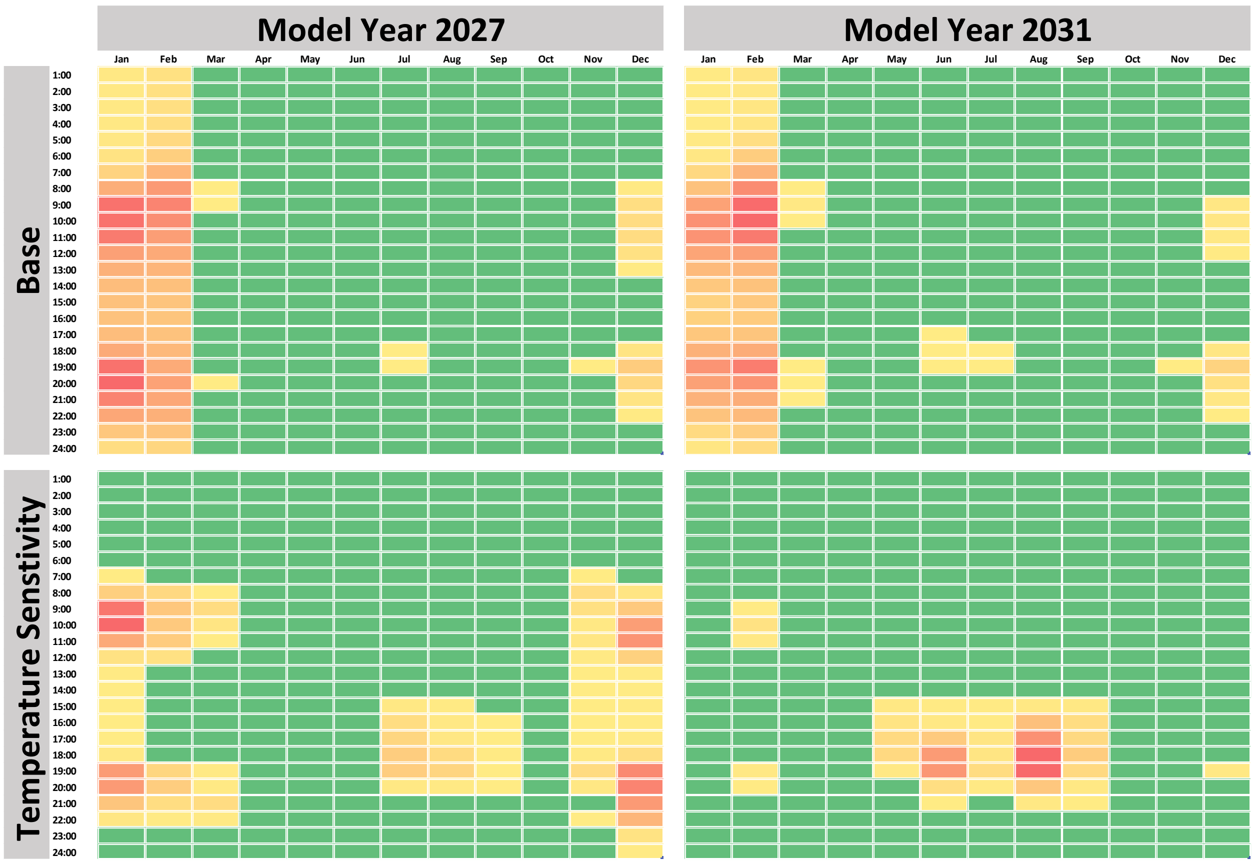


Figure 7-34 presents the effective load carrying capability of the generic resources for the temperature sensitivity as compared to the base scenario. The RAM results presented here were used to develop the inputs for the AURORA portfolio model.

Figure 7-34: Effective Load Carrying Capability for model years 2027 and 2031, Base Scenario and Temperature Sensitivity

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027		ELCC Year 2031	
		Base Scenario	Temp. Sensitivity	Base Scenario	Temp. Sensitivity
Existing Wind	823	9.6%	6.8%	11.2%	6.7%
Skookumchuck Wind	131	29.9%	17.6%	32.8%	9.2%
Lund Hill Solar	150	8.3%	30.3%	7.5%	54.3%
Golden Hills Wind	200	60.5%	49.3%	56.3%	39.3%
Generic MT East Wind1	350	41.4%	28.5%	45.8%	28.1%
Generic MT East Wind2	200	21.8%	13.1%	23.9%	17.7%
Generic MT Central Wind	200	30.1%	23.1%	31.3%	20.9%
Generic WY East Wind	400	40.0%	29.1%	41.1%	32.7%
Generic WY West Wind	400	27.6%	27.2%	29.4%	34.0%
Generic ID Wind	400	24.2%	25.6%	27.4%	28.0%
Generic Offshore Wind	100	48.4%	38.6%	46.6%	27.6%
Generic WA East Wind	100	17.8%	7.8%	15.4%	12.0%
Generic WY East Solar	400	6.3%	13.5%	5.4%	32.5%
Generic WY West Solar	400	6.0%	16.2%	5.8%	36.3%
Generic ID Solar	400	3.4%	16.0%	4.3%	47.3%
Generic WA East Solar	100	4.0%	21.6%	3.6%	45.6%
Generic WA West Solar – Utility-scale	100	1.2%	7.6%	1.8%	20.2%
Generic WA West Solar – DER Roof	100	1.6%	7.6%	2.4%	19.4%
Generic WA West Solar – DER Ground	100	1.2%	7.6%	1.8%	20.2%
BATTERY STORAGE					
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	34.2%	15.8%	36.0%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	66.6%	29.8%	68.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	61.6%	27.4%	63.8%
Flow, 6-hr, 73% RT efficiency	100	29.8%	79.2%	35.6%	84.8%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	89.2%	43.8%	97.8%
SOLAR + BATTERY RESOURCE					
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	22.0%	15.4%	56.6%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	26.0%	23.0%	17.8%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	73.0%	57.7%	64.0%

DEMAND RESPONSE					
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	60.4%	31.6%	61.4%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	69.8%	37.4%	80.8%

It is important to note that this is one model of possible weather changes and provides a preliminary view of the possible impact of warming temperatures. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made that inform the preferred portfolio in this IRP.

PSE will continue to model weather trends under different scenarios to try to better understand how not only extreme summer events can affect resource adequacy, but also to ensure we are planning for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past, there have been three separate regional energy events outside of PSE’s control, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipate future changes to the resource adequacy analysis to include both a winter and summer resource adequacy analysis, and will work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

8 Electric Analysis

This chapter presents the results of the electric analysis.

Contents

1. ANALYSIS OVERVIEW

The electric analysis in the 2021 IRP followed the six-step process outlined below. Steps 1, 3, and 4 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Establish Resource Need
Three types of resource need are identified: peak capacity need, energy need and renewable need.

- Chapter 7 presents the resource adequacy analysis.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 5 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 6 presents the 2021 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Analyze Alternatives and Portfolios Using Deterministic and Stochastic Risk 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.

- All scenarios and sensitivities were analyzed using deterministic optimization 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 and plant forced outages.

- Four portfolios were analyzed using stochastic risk analysis.

4. Analyze Results
Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions for the preferred portfolio.

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

5. Develop Resource Plan

Chapter 3 describes the reasoning behind the strategy chosen for this preferred portfolio.

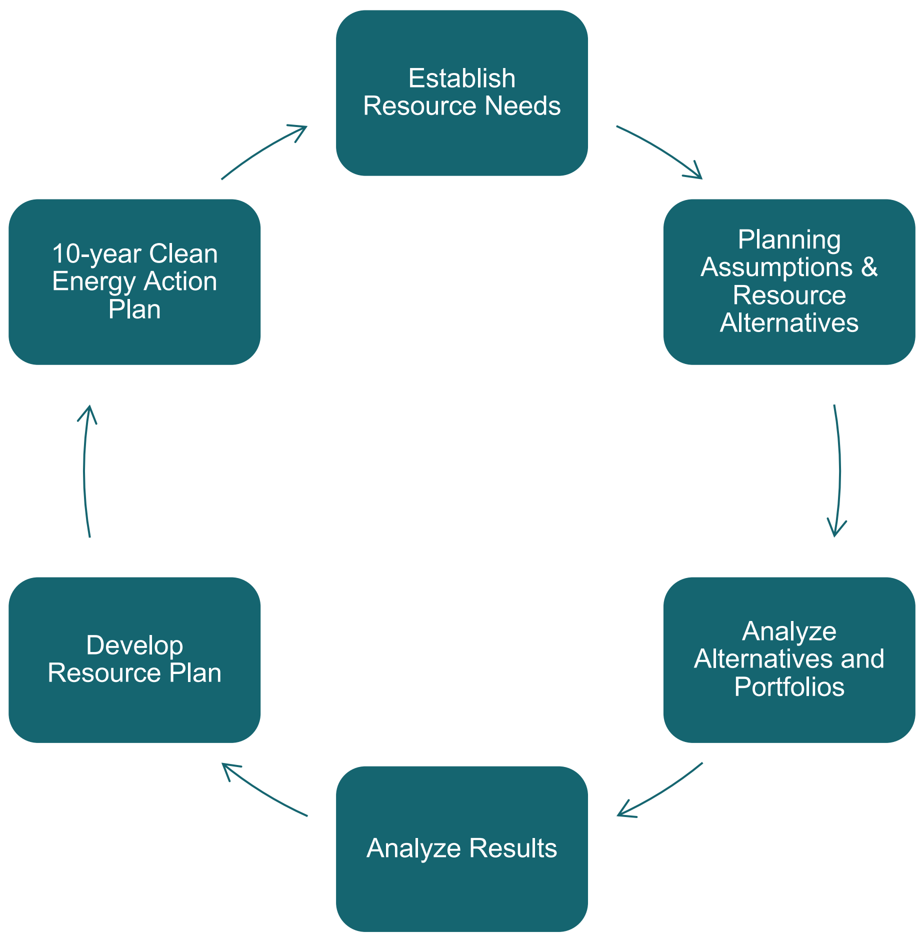
6. Create the 10-year Clean Energy Action Plan

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the IRP Action Plan and the 10-year Clean Energy Action Plan.

- The Action Plan is presented in the Executive Summary, Chapter 1.
- The 10-year Clean Energy Action Plan is presented in Chapter 2.

Figure 8-1 illustrates this process.

Figure 8-1: 2021 IRP Process



2. SUMMARY OF SUBSTANTIVE CHANGES

The 2021 IRP marks a major departure from past IRPs due in large part to the passage of the Clean Energy Transformation Act. Changes in technology, updates to datasets and other advances have also contributed to differences in the 2021 IRP. This section provides a summary of the substantive changes from the 2017 IRP to the 2021 IRP.

ELECTRIC POWER PRICES. Several updates were made to the development of the electric price model. AURORA, the power system software used for electric price simulations, was updated to version 13.4 in the 2021 IRP from version 12.3 in the 2017 IRP. In addition, the AURORA Zonal database was updated to the “2018 version 1” release in the 2021 IRP from the “2016 version 3” release used in the 2017 IRP. A detailed account of all updates to the electric price model is provided throughout Chapter 5 and Appendix G.

GENERIC RESOURCE COSTS. In the 2021 IRP, PSE developed a new process for obtaining generic resource costs. In past IRPs, PSE has relied on consultants to estimate generic resource costs. In the 2021 IRP, PSE aggregated publically available generic resource costs from a variety of sources. These data were presented to stakeholders during a public meeting and stakeholder input was used to refine generic resource cost assumptions. This framework mirrors the generic resource cost development process used by the Northwest Power and Conservation Council’s Generic Resource Advisory Group.

LEGISLATION. In 2019, the Clean Energy Transformation Act (CETA) passed into law. CETA set forth aggressive targets for clean and non-emitting resources. Investor-owned utilities are required to obtain 80 percent of energy sales from non-emitting resources by 2030 and 100 percent of energy sales from non-emitting resources by 2045. This dramatically increases the 15 percent renewable portfolio standard established by RCW 19.285. Furthermore, CETA introduced the need to incorporate the social cost of greenhouse gases and the equitable distribution of customer benefits in the resource planning process.

RESOURCE ADEQUACY MODEL. Between the 2017 IRP and the 2021 IRP, PSE completely overhauled its resource adequacy model. This included moving from a SAS based model to a Python based model that incorporates inputs from regional resource adequacy metrics. A full description of the new resource adequacy model is available in Chapter 7.

ELECTRIC PORTFOLIO MODEL. During the three years since the last IRP was filed, PSE has made significant improvements to the portfolio modeling process. For the 2017 IRP, PSE used an Excel-based model called the Portfolio Screening Model (PSM). This annual model relied on AURORA to dispatch the resources, then the data was pulled into PSM where a solver was added to Excel for the linear programming optimization model. By moving the LP optimization model directly into AURORA, PSE is able to evaluate the economic retirement of resources, increase the selection of new generic resources, model energy storage and hybrid resources, and a utilize a more robust solver engine.

STOCHASTIC MODEL. Since the 2017 IRP, PSE has moved stochastic modeling from a simple SAS model to a full dispatch and forecasting model in AURORA. The SAS model used in 2017 looked at historical trends to forecast out a range of monthly electric prices. By moving the electric price model into AURORA, PSE is able to achieve a more forward looking forecast based on the new legislation and changing mix of resources in the region. In the new stochastic model, no historical data is used, only forward looking changes in the region. AURORA then runs a complete dispatch of resources by hour for each draw and produces a forecast of hourly electric prices instead of monthly prices.

CONSERVATION POTENTIAL ASSESSMENT. In the 2017 IRP, the conservation potential assessment (CPA) was conducted by third-party Navigant Consulting. In the 2021 IRP, PSE retained a different consultant, CADMUS, to conduct the CPA. A full description of the CPA is available in Appendix E.

DEMAND FORECAST. The 2017 IRP base demand forecast was based on 2016 macroeconomic conditions such as population growth and employment; the forecast for the 2021 IRP is based on 2020 macroeconomic conditions. The updates to inputs and equations are documented in Chapter 6.

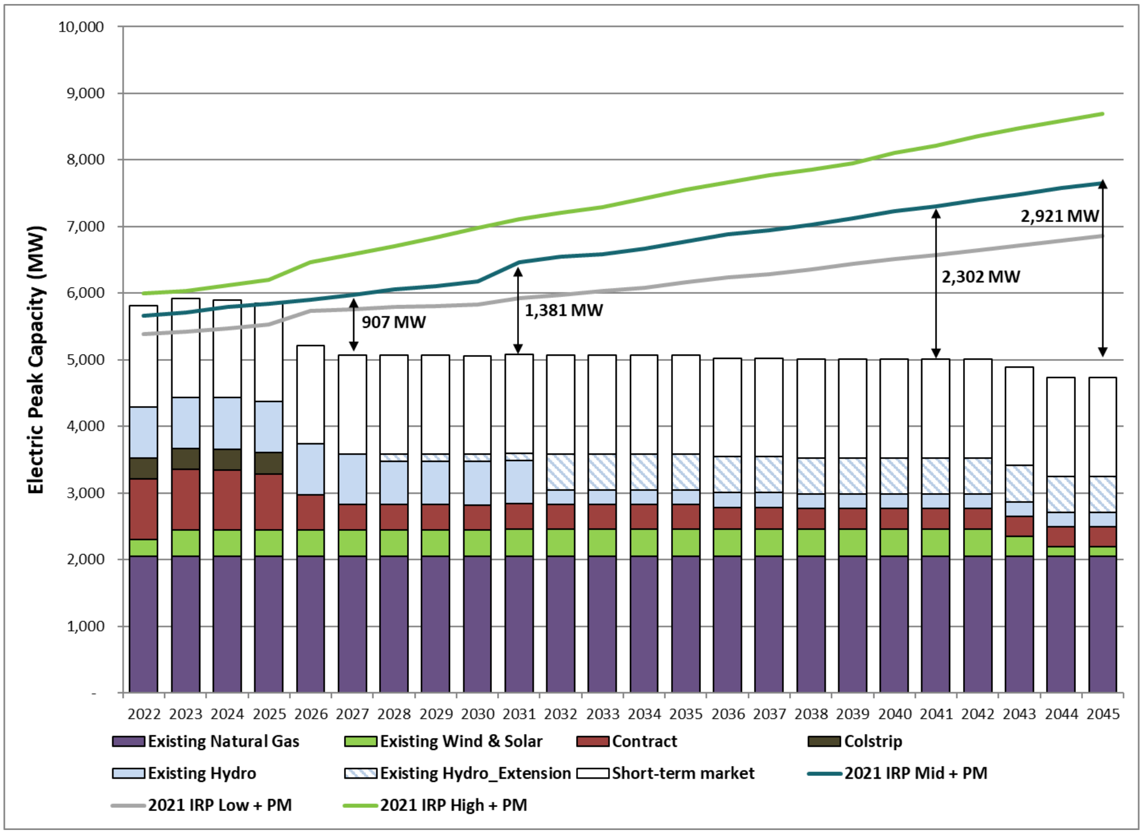
3. RESOURCE NEED

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: 1) peak hour capacity for resource adequacy, i.e., does PSE have the amount of capacity available in each hour to meet customer's electricity needs; 2) hourly energy, i.e., does PSE have enough energy available in every hour to meet customer's electricity needs; and 3) renewable energy, i.e., does PSE have enough renewable and non-emitting resources to meet the clean energy transformation targets.

Peak Capacity Need

Figure 8-2 shows the peak capacity need for the mid demand forecast modeled in this IRP (mid demand refers to the 2021 IRP Base Demand Forecast described in Chapter 6). Using the loss of load probability (LOLP) methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031 before any new conservation. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis. The physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model (RAM).

Figure 8-2: Electric Peak Capacity Need
(physical reliability need, peak hour need compared with existing resources)



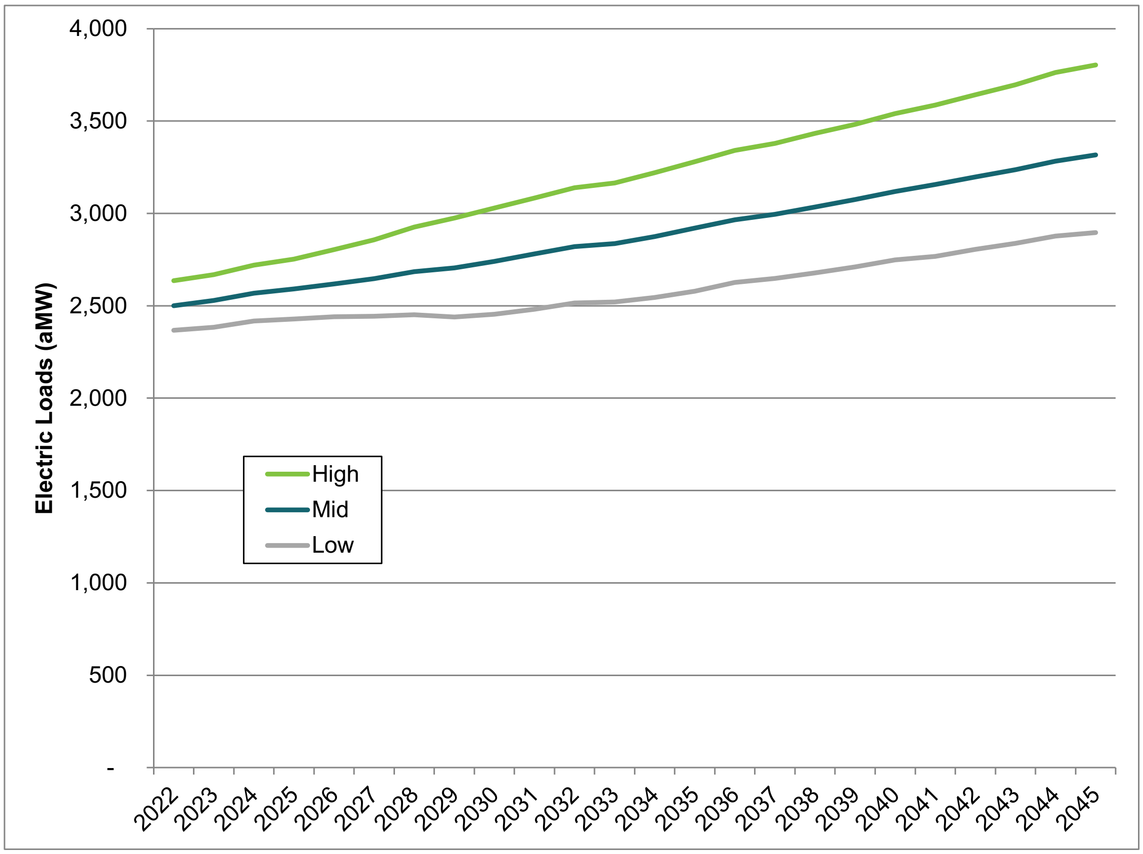
Energy Need

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 in every hour 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 8-3 illustrates the company's energy demand forecast across the planning horizon, based on the energy demand forecast for the Mid, High and Low Scenarios. The Mid Demand Scenario starts at 2,500 aMW in 2022 and grows to 2,740 aMW by 2030 and 3,316 aMW by 2045.

Figure 8-3: Annual Demand Forecast



Renewable Need

Washington State has two renewable energy requirements. The first is a renewable portfolio standard (RPS) that requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. Under the Energy Independence Act (RCW 19.285), PSE must meet 15 percent of retail sales with renewable resources by 2020. PSE has sufficient qualifying renewable resources to meet RPS requirements until 2023, 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 to existing hydro plants.

The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. The difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can be used to meet the requirements.

Washington State's RPS and renewable energy requirements calculate the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, when MWh sales decrease, so does the amount of renewables needed. Achieving demand-side resource targets has precisely this effect. Demand-side resources decrease sales volumes, which then decreases the amount of renewable resources needed.

Figure 8-4 below shows the calculation for the 80 percent renewable requirement in 2030 to meet CETA. The first line of the table provides the estimated demand forecast in the year 2030 before demand-side resources (conservation) are applied. From this value, energy savings from conservation, line losses to adjust the demand forecast to retail sales, load reducing customer programs and PURPA generation[1] are subtracted to yield the sales net of conservation and customer programs (20.4 million MWh). Eighty-percent of this value represents the raw renewable need for 2030 (16.3 million MWh). From this value, existing renewable generation is subtracted to obtain the need for new renewable and non-emitting resources (7.6 million MWh).

Demand-side resources are optimized within the portfolio model and will provide a further reduction to the need shown in the last line of the table. Under normal hydro conditions and without the addition of new renewable/non-emitting resources, PSE will meet 40 percent of sales with renewable resources in 2022.

1 / The Public Utility Regulatory Policies Act of 1978 (PURPA) created a new class of generating resources known as qualifying facilities. Energy from qualifying facilities is included in this line item.

Figure 8-4: Calculation of 2021 IRP Renewable Need for 2030

	MWh
2030 Estimated Demand Forecast before Conservation[1]	24,004,160
Conservation: Codes & Standards, Solar PV	(774,387)
Line Losses	(1,579,625)
Load Reducing Customer Programs & PURPA	(1,243,449)
Sales Net of Conservation and Customer Programs	20,406,699
80% of Estimated Net Sales	16,325,360
Existing Non-emitting Resources[2]	(8,691,268)
Need for New Renewable/Non-emitting Resources	7,634,092

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022
2. Assumes normal hydro conditions and P50 wind and solar

Figure 8-5 below illustrates the renewable energy need for both RCW 19.285 and CETA based on the mid demand forecast, before any additional demand-side resources are added.

Figure 8-5: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements (before demand-side resources)

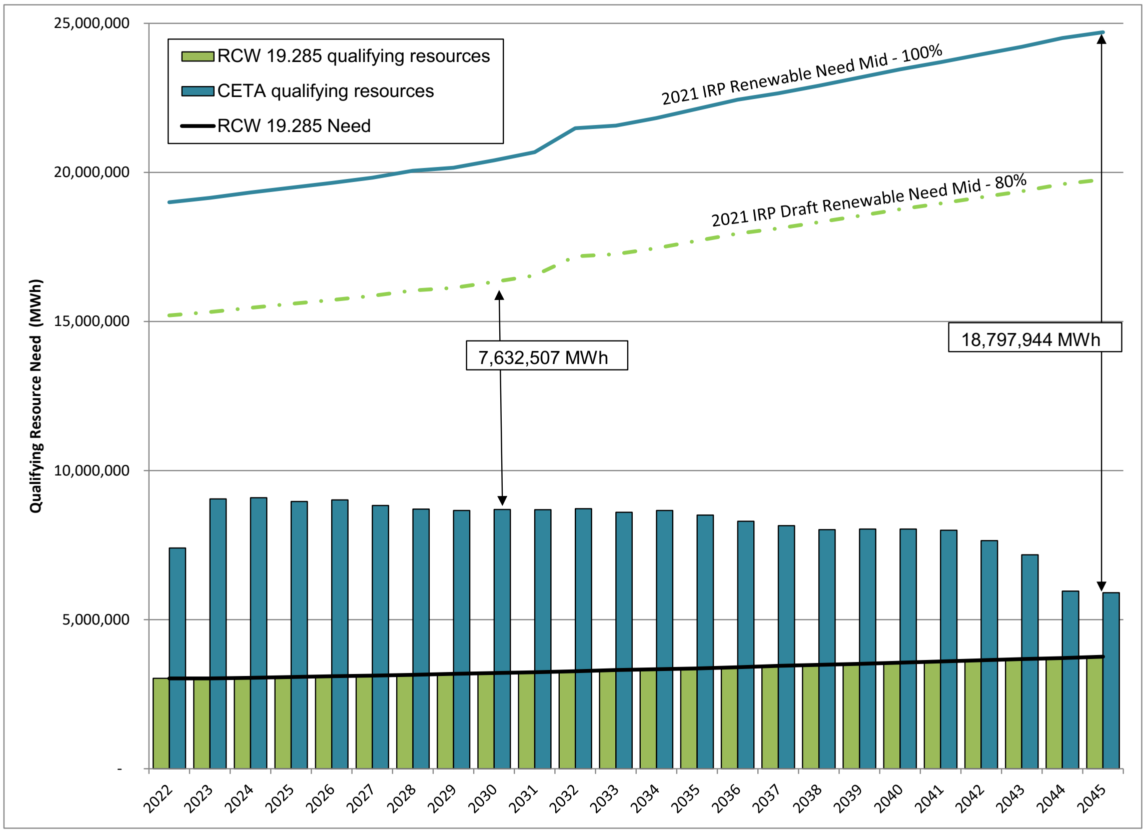
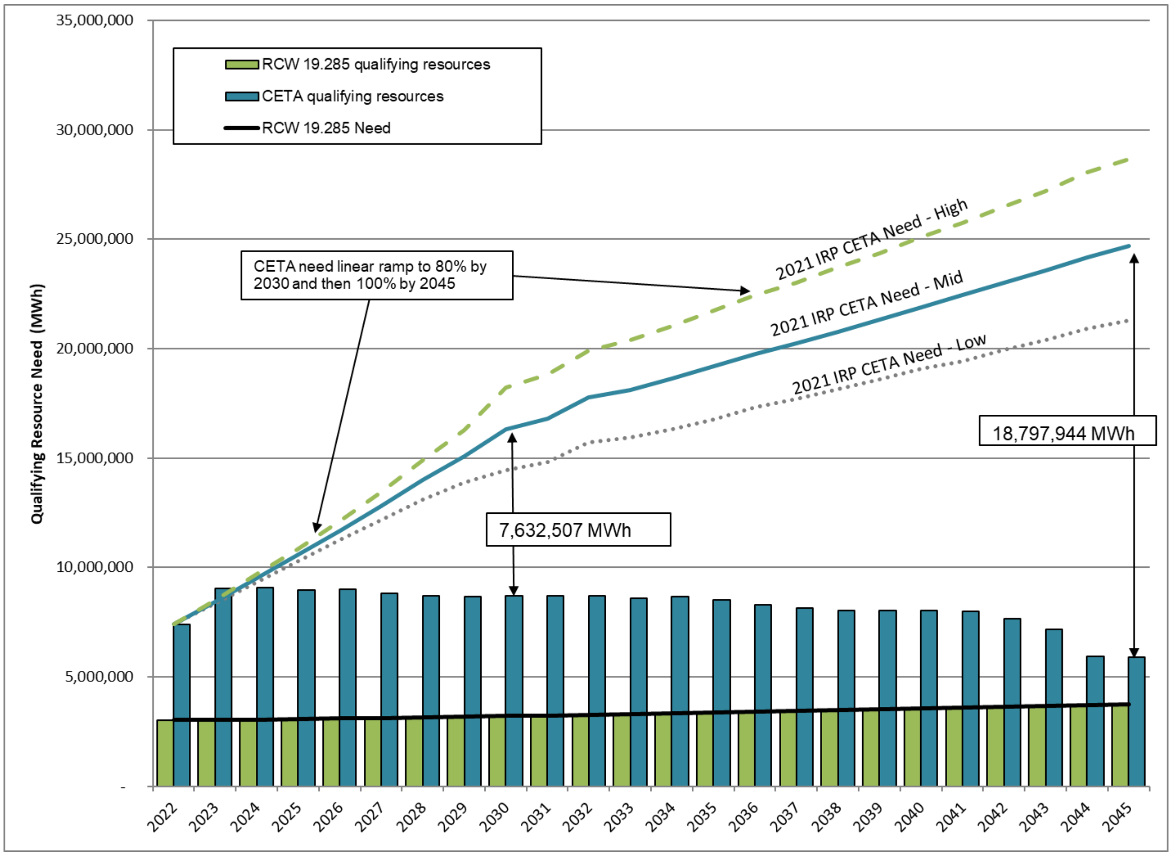


Figure 8-6 below assumes a linear ramp to reach the CETA 80 percent clean energy standard in 2030 and 100 percent clean energy standard in 2045. The linear ramp is needed to ensure that the portfolio model gradually adds resources to meet clean energy standards, rather than waiting until the final year before a goal must be achieved to add them. The linear ramp starts in 2022, as the IRP assumes all new resources are self-builds that will take at least two years before becoming operational. Since the IRP analysis starts in 2022, the earliest a resource can be built is 2024.

Figure 8-6: Renewable Need and Linear Ramp for CETA (before demand-side resources)



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.[2] The customer benefit analysis is used to inform the equitable distribution of burdens and benefits in the resource planning process to ensure that all customers are benefiting from the transition to clean energy.

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 PSE to learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

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.

Stochastic Risk Analysis

In this stage of the resource plan analysis, PSE examines how different resource strategies respond to the types of risk that go hand-in-hand with future uncertainty. Inputs that were static in the deterministic analysis are deliberately varied to create simulations called "draws" used to analyze the different portfolios. This allows PSE to learn how different strategies perform with regard to cost and risk across a wide range of power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

With stochastic risk analysis, PSE tests the robustness of different portfolios; in other words, determine 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.

2 / 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.

For this purpose, PSE takes some of the portfolios (drawn from the deterministic analysis of scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, gas prices, hydro generation, wind and solar generation, load forecasts (energy and peak), and plant forced outages. This stochastic analysis enables PSE to evaluate the risk associated with the selected portfolios to inform the preferred portfolio.

Customer Benefits Analysis

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. The analysis of the equitable distribution of burdens and benefits into the resource planning process is new in the 2021 IRP. PSE is excited to incorporate these new ideas into the resource planning process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. Below is a brief overview of PSE's first attempt to incorporate customer benefits into the IRP process.

Incorporating the equitable distribution of burdens and benefits into the resource planning process requires a multifaceted approach. Therefore, PSE has developed several tools and methods; these include the Economic, Health and Environmental Benefits (EHEB) Assessment, the Equity Advisory Group (EAG) and the Customer Benefits Analysis.

The EHEB Assessment is an analysis outside of the IRP portfolio modeling process that seeks to determine how benefits and burdens are distributed among PSE customers. The EHEB Assessment provides a snapshot of current conditions across PSE's service area that shows where disparities exist and identifies key constituencies (vulnerable populations and highly impacted communities) which are at greater risk according to a range of customer benefit indicators. Customer benefit indicators are measures that speak to the degree to which specific groups are burdened or benefit from public health, environmental, economic and societal impacts. A full description of the methods and results of the EHEB Assessment are provided in Appendix K.

More directly related to the portfolio development process is the Customer Benefit Analysis. Historically, the IRP selected a preferred portfolio based on cost and reliability alone. CETA legislation has added the consideration of customer benefit indicators to these criteria. Since existing portfolio optimization software lacks the ability to incorporate customer benefit indicators, the Customer Benefit Analysis is performed outside of the portfolio and iterated into the overall portfolio development process. The Customer Benefit Analysis ranks portfolios based on a number of customer benefit indicators. Portfolios with high ranks help to inform key components

3 / Each of the 250 simulations is for the 24-year IRP forecasting period, 2022 through 2045.

that should be incorporated into the preferred portfolio. Preferred portfolio candidates are then incorporated into the ranking process to ensure they provide a suitable balance of customer benefit indicators. It is not enough to score well in one or two customer benefit indicator areas, a good portfolio must provide a range of benefits.

Portfolio outputs were mapped to customer benefit indicators using PSE's best judgement. The customer benefit indicators selected for the Customer Benefit Analysis do not necessarily align directly to the customer benefit indicators used in the EHEB Assessment. This is because of data availability constraints of each analysis. In future IRP cycles, PSE aims to better align customer benefit indicators across all analyses through customer input and insights from the Equity Advisory Group. Figure 8-7 provides an overview of the customer benefit indictors used in the Customer Benefit Analysis.

Figure 8-7: Customer Benefit Indicators for Portfolio Analysis

Area	Customer Benefit Indicator	Definition
Air Quality	Particulate Matter Emissions	Total emissions from thermal resources. Measured in tons.
	SO_2 Emissions	Total emissions from thermal resources. Measured in tons.
	NO_x Emissions	Total emissions from thermal resources. Measured in tons.
Environment	Renewable Generation	Energy generated from utility-scale renewable resources. Measured in MWh.
	Customer Programs	Energy generated from Green Direct, Green Power and Qualifying Resources. Measured in MWh.
	Energy Efficiency	Energy savings from energy efficiency, distribution efficiency and codes and standards. Measured in MWh.
	Distributed Generation	Energy generated from distributed solar (rooftop and ground-mounted), non-wires alternatives and net metering. Measured in MWh.
Economic	Portfolio Cost	Levelized cost of the portfolio. Measured in billions of dollars.
Energy Resiliency	Storage	Capacity of distributed storage added to the portfolio. Measured in MW.

Area	Customer Benefit Indicator	Definition
Climate Change	Social Cost of Greenhouse Gases	Levelized social cost of greenhouse gases. Measured in billions of dollars.
	Greenhouse Gas Emissions	CO_2 equivalent emissions. Measured in tons.
Market Position	Market Purchases	Energy purchased from market. Measured in MWh.
Resource Adequacy	Demand Response	Capacity of demand response programs in the portfolio. Measured in MW.

The customer benefit indicators are measured values from each portfolio analyzed. Measurements may be taken over various intervals along the planning horizon to gain an understanding of how customer benefit indicators evolve over time. For example, greenhouse gas emissions may be measured in the year 2031 to understand climate impacts at the 10-year Clean Energy Action Plan planning horizon as well as in the year 2045 to get a view of climate impacts for the entire IRP period.

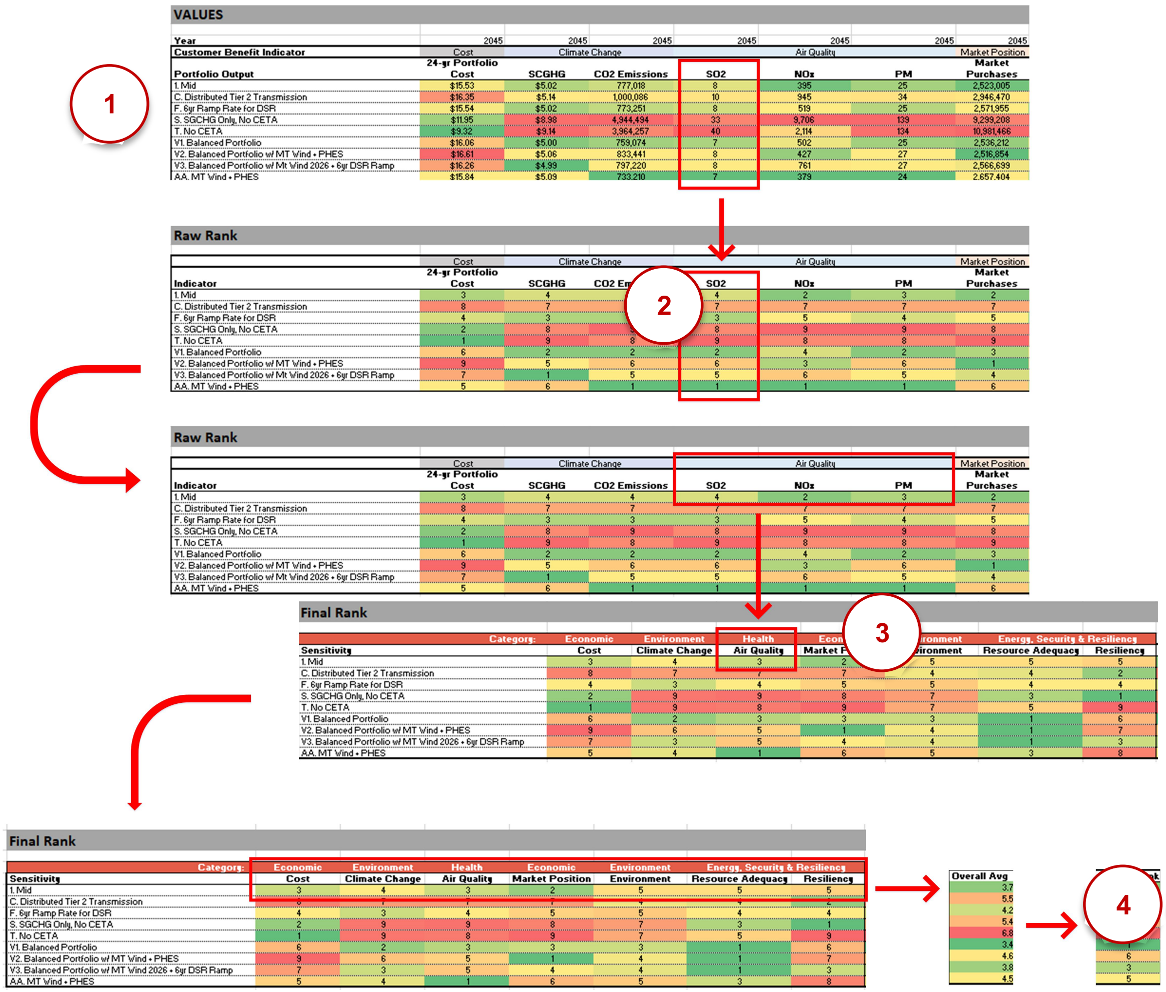
To make meaningful decisions about how different portfolios impact PSE's customers, the relative strengths and weaknesses of the portfolios are compared using the different customer benefit indicators.

The process to compare portfolio tradeoffs is depicted in Figure 8-8:

1. Values for each customer benefit indicator are extracted from the AURORA portfolio model for each portfolio being compared.
2. Values for each customer benefit indicator are ranked; where the most beneficial (or least burdensome) portfolio receives a rank of 1 and the least beneficial (or most burdensome) portfolio receives a rank of 'n', where there are n portfolios compared.
3. Individual customer benefit indicators are aggregated into customer benefit areas to more evenly distribute the benefit of each the various areas. For example, the ranks of SO_2, NO_x and PM are averaged together by portfolio to obtain an air quality rank.
4. Finally, for each portfolio, all the customer benefit indicator area ranks are averaged together to produce an overall average which is then converted to an overall rank.

The portfolio with the rank of 1 would provide the best balance of all customer benefit indicators. Furthermore, specific pieces of information may be used throughout the portfolio development process to help derive a more desirable portfolio. For example, the results for Sensitivity C: Distributed, Tier 2 Transmission Constraints, obtain favorable ranks in the Environment customer benefit indicator area, due to the large amount of energy efficiency and distributed resources in the portfolio. These elements may be incorporated into the preferred portfolio to improve its benefit to the environment.

Figure 8-8: Portfolio Ranking Process



NOTE: Data contained within this figure is draft and intended for demonstration purposes only. The results of the Customer Benefit Analysis is provided later in this chapter and a complete set of customer benefit indicator ranks is provided in Appendix H.

PSE recognizes the customer benefit indicators used in the Final IRP are preliminary and will evolve with time. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process. In particular, two areas of consideration that require further stakeholder input have been identified so far:

- **Qualitative measures:** Although most customer benefit indicators are directly tied to quantitative metrics from the portfolio output, PSE recognizes that some customer benefit indicators may also be qualitative in nature. As qualitative measures are developed, this work may evolve the portfolio customer benefit indicator framework to incorporate indicators which are not directly related to specific portfolio model outputs.

- **Weighting factors:** Additionally, PSE understands some indicators may be more important than others to customers, especially for highly impacted communities and vulnerable populations, and thus require additional collaboration with stakeholders to determine the best weighting to apply across indicators and/or portfolios.

5. KEY FINDINGS

This section summarizes the assumptions for the economic scenarios, portfolio sensitivities and customer benefits indicators developed for this IRP; discusses the key findings from these analyses; and summarizes the optimal portfolio costs and builds produced by the scenario, sensitivity and customer benefits analyses. The following tables are included.

- Figure 8-9: 2021 IRP Electric Portfolio Scenarios and Sensitivities
- Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
- Figure 8-11: Relative Optimal Portfolio Builds by Sensitivity

> > > See Chapter 5, Key Assumptions, for a detailed description of the scenarios and sensitivities and the key assumptions used to create them: customer demand, natural gas prices, possible CO_2 prices, resource costs (demand-side and supply-side) and power prices.

> > > See Appendix D, Electric Resource Alternatives, for a detailed discussion of existing electric resources and resource alternatives.

> > > See Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions, for a detailed discussion of the customer indicators developed for the customer benefits analysis.

Summary of Assumptions

Figure 8-9: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast [a], mid electric price forecast
2	Low	Low gas price, low demand forecast, low electric price forecast
3	High	High gas price, high demand forecast, high electric price forecast
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon-free combustion turbines using biodiesel as the fuel.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus reduced access to the Mid-C market for both sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040 (8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources. (energy efficiency, distribution efficiency and demand response)
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

NOTE
a. Mid demand refers to the 2021 IRP Base Demand Forecast.

Key Findings: Economic Scenarios

The quantitative results produced by extensive analytical and statistical evaluation led to the key findings summarized in the following pages.

Economic Scenarios

Portfolio additions are very similar across all three economic scenarios. The amount of resources added increased or decreased based on high and low load forecasts, respectively. Direct emissions are lower with the retirement of Centralia and the removal of Colstrip 3 & 4 in 2025 as part of CETA compliance, and continue trending down throughout the planning horizon. The renewable requirement to meet CETA drives the renewable builds for each scenario.

Key Findings: Portfolio Sensitivities

Future Market Availability

Renewable overgeneration occurs when renewable resources generate more energy than there is demand. Limiting market access, either sales or purchases, increases the cost of CETA implementation by overbuilding battery storage to store the overgeneration of renewable resources instead of selling it to the market. Reducing the reliance on short-term market during peak increases the peak need for new capacity resources or firm resource adequacy qualifying contracts.

Transmission Constraints and Build Limitations

The majority of new renewable resources included in the 2021 IRP are sited outside of PSE's service area. These resources require transmission to deliver power from the generation site to PSE's customers. Transmission is a relatively scarce asset, and there is uncertainty about PSE's ability to procure transmission for the optimal renewable resource mix. Varying the amount of transmission available to regions around PSE's service area measures the impact of these uncertainties.

There is little impact on portfolio build decisions when transmission constraints are modeled to match transmission procurement expectations and timelines (Sensitivity D). This suggests that the generally unconstrained transmission identified for this IRP is a reasonable assumption for the comparative portfolio sensitivity analysis.

However, portfolio build decisions shift when transmission constraints limit resource build to under 3,070 MW outside of PSE's service area (Sensitivity C). More distributed solar resources located within PSE's service territory are selected and battery storage is increased to help balance generation and demand.

When contracting firm transmission less than the nameplate capacity of resources, site location and fixed transmission costs are important considerations. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due to the significant portion of time that wind resources spend generating at or near nameplate capacity (i.e., rated power).

Conservation Alternatives

Across the conservation alternatives evaluated for this IRP, cost-effective demand-side resources, portfolio costs and build decisions remain relatively stable. Incremental energy savings by bundle vary depending on the conservation alternative driving the bundle selection. Changes in the assumptions for the conservation alternatives pushed more energy savings into lower bundles. In some results, decreased investment in conservation measures is supplemented by increased demand response measures. By changing the ramp rates and discount rate of the bundles, the portfolio moves into lower bundle levels than the Mid portfolio, but still adds a similar or lower amount of conservation as the Mid portfolio. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045.

Demand response and conservation are important resource options in PSE's portfolio, and they are considered load-reducing resources in the calculation of the CETA renewable need. Absent these resources, the portfolio adds more renewable resources, resulting in increased portfolio costs.

Social Cost of Greenhouse Gases (SCGHG) and CO_2 Regulation

Different modeling approaches to incorporating the social cost of greenhouse gases do not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements.

Whether modeling SCGHG as a fixed cost planning adder, a dispatch cost in the resource selection or as a dispatch cost in both the resource selection and hourly portfolio run, CETA requirements for renewable resources are the key driver of portfolio resource additions and costs.

Using the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) to calculate upstream emissions increased those emissions for natural gas, but did not change resource builds or retirements compared to utilizing the IPCC's Fourth Assessment Report (AR4).

Applying a Federal CO_2 tax in addition to SCGHG as a fixed-cost planning adder does appear to alter portfolio build decisions, resulting in the addition of fewer thermal resources. Dispatch from thermal plants also declines over time resulting in lower portfolio emissions.

Emissions Reduction

Reducing emissions and even achieving a 100 percent renewable portfolio may be possible with existing technologies, but the cost to do so is high. Large investments in storage to replace thermal resources results in high portfolio costs. Although direct emissions from generating resources are reduced, indirect emissions from market purchases increase because energy purchased from the market is needed to support the storage-heavy portfolios.

Demand Forecast Adjustments

Using alternative temperature data to forecast demand and use in the resource adequacy analysis lowers the demand forecast and the peak capacity need. The lower demand forecast lowers the CETA renewable need. The reduction in peak capacity need results in all future needs being met by new renewable resources and battery energy storage.

On the other hand, fuel switching from gas to electric results in a higher demand forecast and higher CETA renewable need. Resource builds of every resource type increased to support the higher loads.

CETA Costs

CETA requirements drive renewable resource build decisions. Absent CETA requirements, no renewable resources are added to the portfolio except a wind resource towards the end of the planning horizon, which is needed to maintain compliance with RCW 19.285, and more flexible capacity resources are added over time to meet increasing peak capacity need. The cost of the No CETA portfolio is significantly lower than the CETA-compliant portfolios. This is an initial attempt to evaluate the incremental cost of compliance. Portfolio costs stay within the 2 percent annual revenue requirement for the early part of the planning horizon, but increase over time and exceed the 2 percent cost threshold by 2030.

Balanced Portfolio

A forecast of distributed energy resources (DERs) and customer programs ramped in over time helps to spread the revenue requirement throughout the planning horizon. Although DERs have lower peak capacity contributions and increase portfolio costs, there are customer benefits to be gained related to air quality and environment. Significant emission reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. The availability of biodiesel fuel for peaking capacity resources further reduces emissions.

Relative Optimal Portfolio Costs, Builds and Emissions

Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
(dollars in billions, NPV including end effects)

	24-Yr Levelized Costs ($ Billions)			
Portfolio	**Revenue Requirement**	**SCGHG Adder**	**Total**	**Change from Mid**
1 Mid	$15.53	$5.09	$20.62	$0.00
2 Low	$12.08	$4.53	$16.61	($4.01)
3 High	$21.37	$5.74	$27.11	$6.49
A Renewable Overgeneration	$17.11	$4.45	$21.55	$0.93
B Market Reliance	$16.57	$5.19	$21.76	$1.14
C Distributed Transmission	$16.35	$5.21	$21.56	$0.94
D Transmission/build constraints - time delayed (option 2)	$15.54	$5.11	$20.65	$0.03
F 6-Yr DSR Ramp	$15.54	$5.09	$20.62	$0.00
G NEI DSR	$15.24	$5.12	$20.36	($0.26)
H Social Discount DSR	$15.77	$5.16	$20.94	$0.32
I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.10	$20.51	($0.11)
J SCGHG Dispatch Cost - LTCE and Hourly Models	$18.45	$4.81	$23.26	$2.64
K AR5 Upstream Emissions	$15.56	$5.14	$20.71	$0.09
L SCGHG Federal CO2 Tax as Fixed Cost	$17.77	$4.71	$22.47	$1.86
M Alternative Fuel for Peakers - Biodiesel	$15.53	$4.99	$20.52	($0.10)
N1 100% Renewable by 2030 Batteries	$32.03	$3.76	$35.79	$15.17
N2 100% Renewable by 2030 PSH	$66.64	$2.52	$69.16	$48.54
O1 100% Renewable by 2045 Batteries	$23.35	$4.81	$28.16	$7.54
O2 100% Renewable by 2045 PSH	$46.95	$3.98	$50.94	$30.32
P1 No Thermal Before 2030, 2Hr LiIon	$30.84	$6.38	$37.22	$16.60
P2 No Thermal Before 2030, PHES	$22.85	$4.77	$27.62	$7.00

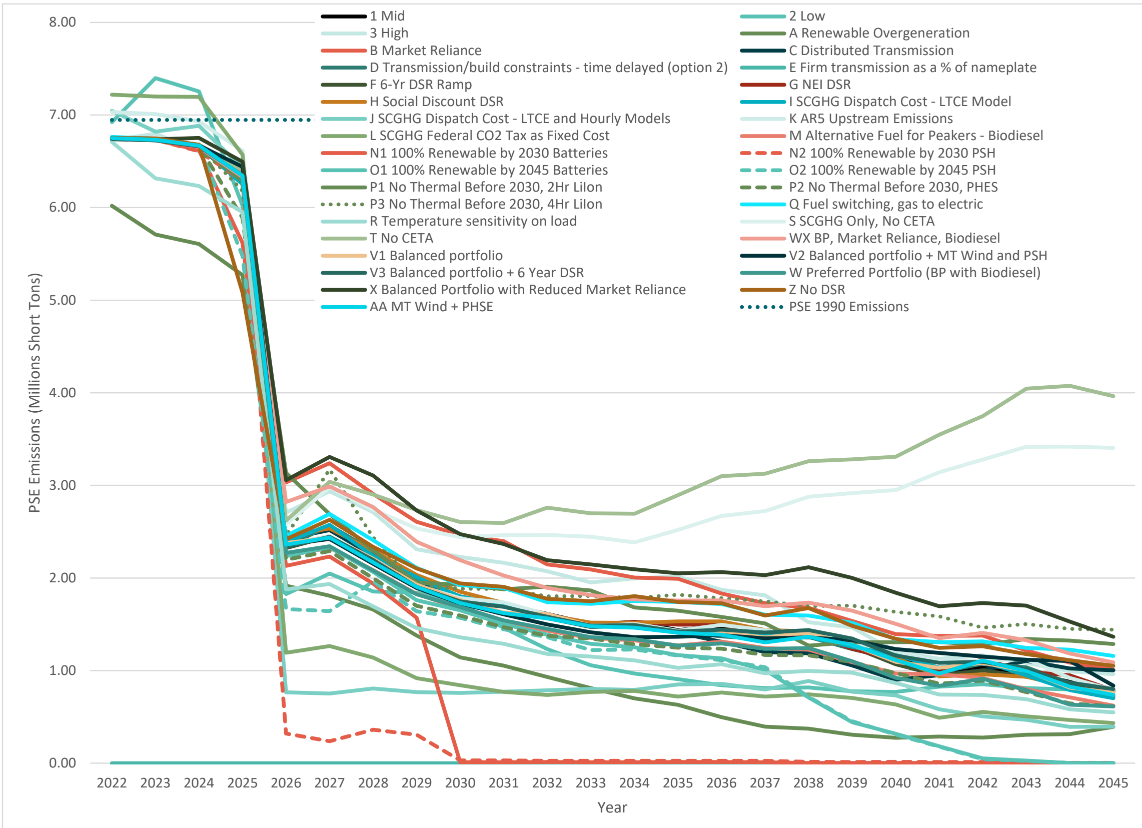
P3 No Thermal Before 2030, 4Hr LiIon	$39.01	$6.69	$45.70	$25.08
Q Fuel switching, gas to electric	$19.56	$5.60	$25.16	$4.54
R Temperature sensitivity on load	$13.53	$4.69	$18.22	($2.40)
S SCGHG Only, No CETA	$9.29	$8.86	$18.16	($2.46)
T No CETA	$9.32	$9.27	$18.59	($2.03)
V1 Balanced portfolio	$16.06	$5.07	$21.14	$0.52
V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.12	$21.73	$1.11
V3 Balanced portfolio + 6 Year DSR	$16.26	$5.06	$21.32	$0.70
W Preferred Portfolio (BP with Biodiesel)	$16.10	$4.96	$21.06	$0.44
X Balanced Portfolio with Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95
WX BP, Market Reliance, Biodiesel	$17.30	$5.06	$22.36	$1.74
Z No DSR	$17.54	$5.56	$23.10	$2.48
AA MT Wind + PHSE	$15.84	$5.16	$20.99	$0.37

Figure 8-11: Relative Optimal Portfolio Builds by Scenario and Sensitivity (cumulative nameplate capacity in MW for each resource addition by 2045)

	Resource Additions by 2045, Nameplate (MW)											
Portfolio	Demand-side Resources	Battery Energy Storage	Solar - Ground and Rooftop	Demand Response	DSP Non-Wire Alternatives	Biomass	Solar	Wind	Renewable + Storage Hybrid	Pump Hydro Storage	Peaking Capacity	Total
1 Mid	1,497	550	0	123	118	90	1,393	3,350	250	0	948	**8,319**
2 Low	1,537	275	0	181	118	30	1,096	2,450	250	0	237	**6,175**
3 High	1,733	900	0	128	118	150	2,292	3,850	0	0	1,659	**10,830**
A Renewable Overgeneration	1,537	1,525	0	192	118	150	2,388	2,250	725	0	474	**9,359**
B Market Reliance	1,497	650	50	173	118	135	995	3,350	375	0	1,732	**9,075**
C Distributed Transmission	1,537	1,050	2,700	178	118	150	500	2,615	125	0	1,003	**9,976**
D Transmission/ build constraints - time delayed (option 2)	1,537	650	0	180	118	135	1,295	3,300	250	0	948	**8,413**
F 6-Yr DSR Ramp	1,372	625	0	175	118	150	1,394	3,150	500	0	966	**8,449**
G NEI DSR	1,304	450	0	188	118	150	1,393	3,450	125	0	1,185	**8,363**
H Social Discount DSR	1,179	675	0	195	118	150	1,391	3,150	625	0	948	**8,431**
I SCGHG Dispatch Cost - LTCE Model	1,497	875	0	188	118	135	1,294	3,150	375	0	766	**8,398**
J SCGHG Dispatch Cost - LTCE and Hourly Models	1,497	850	0	205	118	60	996	3,550	375	0	747	**8,397**
K AR5 Upstream Emissions	1,497	625	0	140	118	150	1,393	3,150	250	0	948	**8,270**
L SCGHG Federal CO2 Tax as Fixed Cost	1,537	525	0	183	118	135	1,395	3,150	250	0	829	**8,122**
M Alternative Fuel for Peakers - Biodiesel	1,537	700	0	185	118	75	1,593	3,150	250	0	948	**8,557**
N1 100% Renewable by 2030 Batteries	1,304	26,200	0	59	118	0	1,994	3,850	0	0	0	**33,523**
N2 100% Renewable by 2030 PSH	1,169	0	0	59	118	75	3,268	3,600	622	21,300	0	**30,211**
O1 100% Renewable by 2045 Batteries	1,304	24,500	0	128	118	0	1,692	3,950	0	0	0	**31,692**

O2 100% Renewable by 2045 PSH	1,537	0	0	204	118	0	99	3,650	1,249	19,600	0	**26,458**
P1 No Thermal Before 2030, 2Hr LiIon	1,372	4,300	0	178	118	15	1,695	3,550	125	0	474	**11,827**
P2 No Thermal Before 2030, PHES	1,304	1,025	0	122	118	15	2,294	3,550	0	2,700	18	**11,146**
P3 No Thermal Before 2030, 4Hr LiIon	1,372	4,425	0	129	118	0	2,292	3,250	0	0	0	**11,586**
Q Fuel switching, gas to electric	1,537	2,000	0	108	118	135	4,880	3,850	825	0	2,961	**16,414**
R Temperature sensitivity on load	1,372	500	0	130	118	150	1,195	3,150	0	0	0	**6,614**
S SCGHG Only, No CETA	1,179	50	0	203	118	0	0	350	0	0	1,896	**3,795**
T No CETA	1,042	0	0	123	118	0	0	350	0	0	2,133	**3,766**
V1 Balanced portfolio	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,641**
V2 Balanced portfolio + MT Wind and PSH	1,784	375	680	217	118	120	895	3,150	425	0	948	**8,711**
V3 Balanced portfolio + 6 Year DSR	1,658	675	680	217	118	120	895	3,450	125	0	1,003	**8,940**
W Preferred Portfolio (BP with Biodiesel)	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,354**
X Balanced Portfolio with Reduced Market Reliance	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,321**
WX BP, Market Reliance, Biodiesel	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,607**
Z No DSR	690	1,250	0	0	118	150	2,688	3,450	500	0	1,422	**10,268**
AA MT Wind + PHSE	1,497	300	0	182	118	150	1,094	3,350	425	0	948	**8,064**

Figure 8-12: Relative Optimal Portfolio Emissions by Scenario and Sensitivity (annual direct portfolio emissions by year)



6. ECONOMIC SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all three economic scenarios look very much alike given the generic resource options. The mix of resources is similar and the amount of resources added varied depending on the load forecasts. In the Low economic scenario fewer resources are added due to lower demand, lower peak need and lower renewable need. In the High economic scenario, more resources are added due to higher demand, higher peak need and higher renewable need. Figure 8-13, shows the levelized cost by scenario while Figure 8-14 shows the optimal portfolio builds by scenario.

Figure 8-13: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

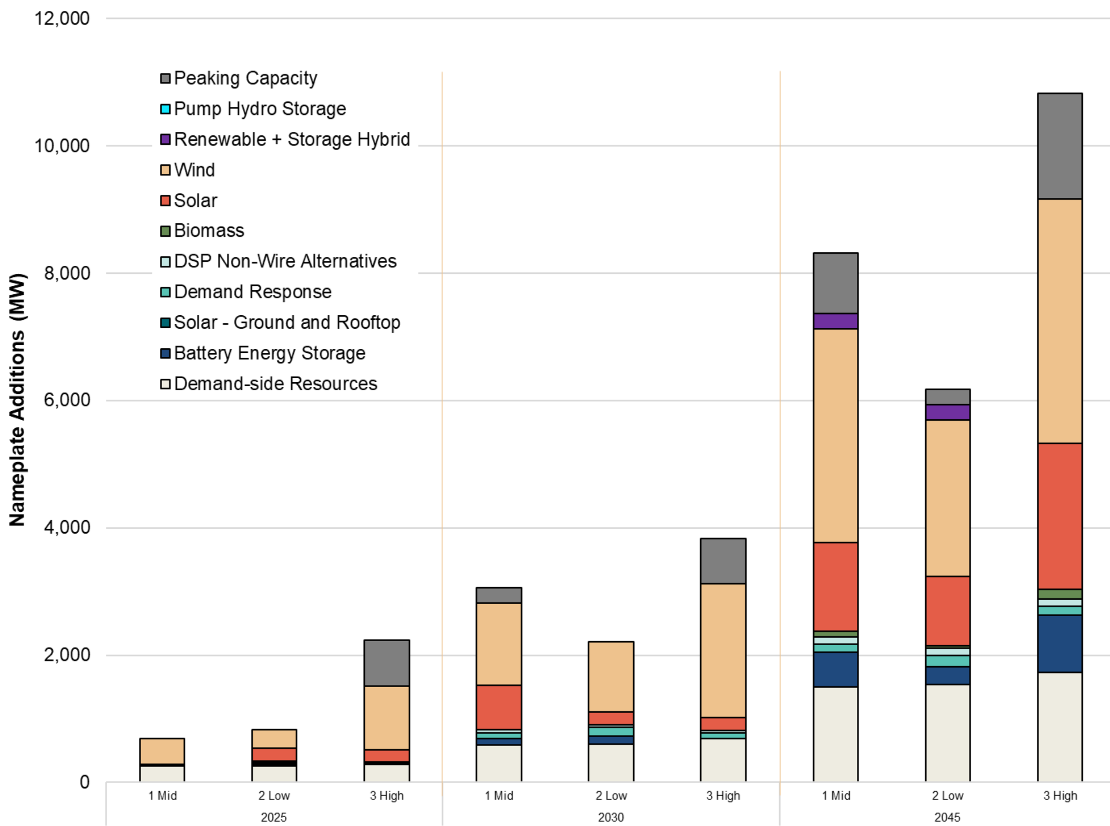
		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
2	Low Scenario	$12.08	$4.53	$16.61	($3.45)
3	High Scenario	$21.37	$5.74	$27.11	$5.84

Figure 8-14: Relative Optimal Portfolio Builds by Scenario
(cumulative nameplate capacity in MW for each resource addition by 2045)

Resource Additions by 2045	1 Mid	2 Low	3 High
Demand-side Resources	1,497 MW	1,537 MW	1,733 MW
Battery Energy Storage	550 MW	275 MW	900 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	181 MW	128 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	3,576 MW	6,292 MW
Biomass	90 MW	30 MW	150 MW
Solar	1,393 MW	1,096 MW	2,292 MW
Wind	3,350 MW	2,450 MW	3,850 MW
Renewable + Storage Hybrid	250 MW	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	237 MW	1,659 MW

Figure 8-15 below displays the megawatt additions for the deterministic analysis of optimal portfolios for all three scenarios in 2025, 2030 and 2045. No new resources are added until 2024. See Appendix H, Electric Analysis Inputs and Results, for more detailed information.

Figure 8-15: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Portfolio Emissions

Figure 8-16 shows CO_2 emissions for the Mid, Low and High Scenarios. The chart shows the direct emissions from portfolio resources for each scenario and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. Despite varying demand, natural gas price and electric price forecasts, the three scenarios all converge on a similar quantity of direct emissions by 2045, driven by CETA renewable energy targets.

Figure 8-16: CO_2 Emissions for the Mid, Low and High Scenarios (does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)

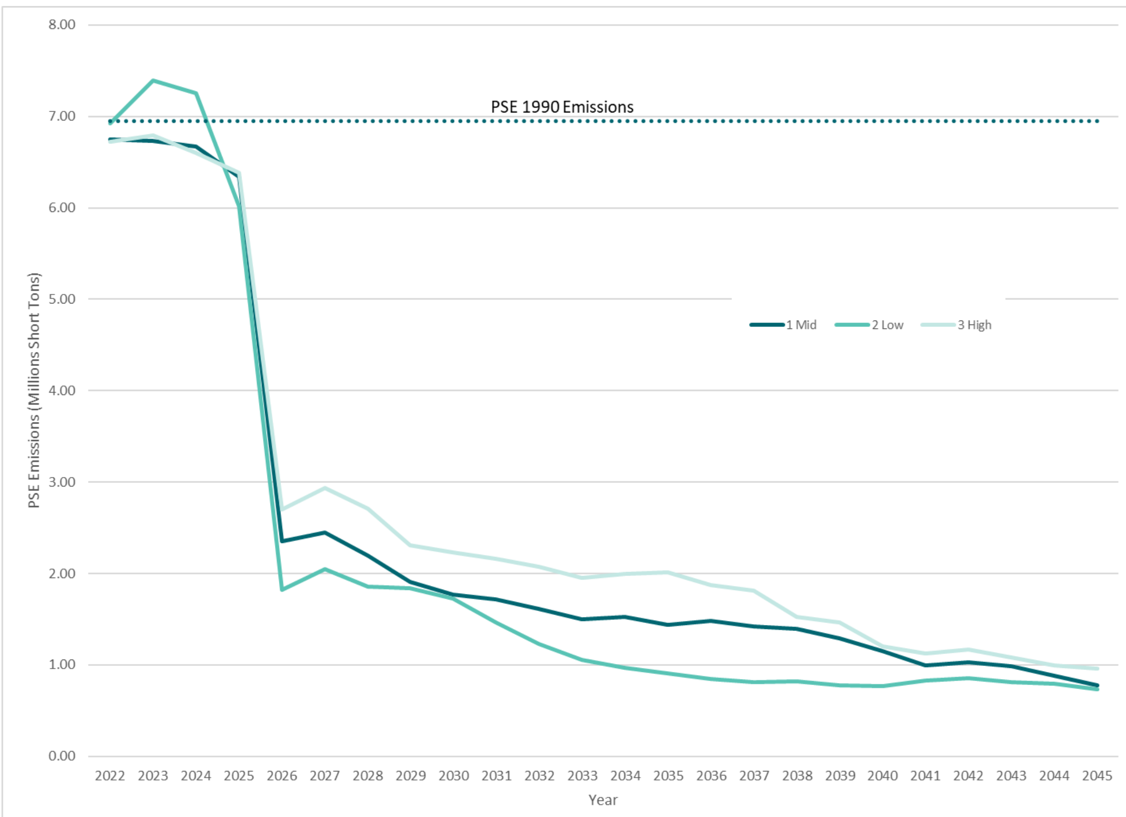
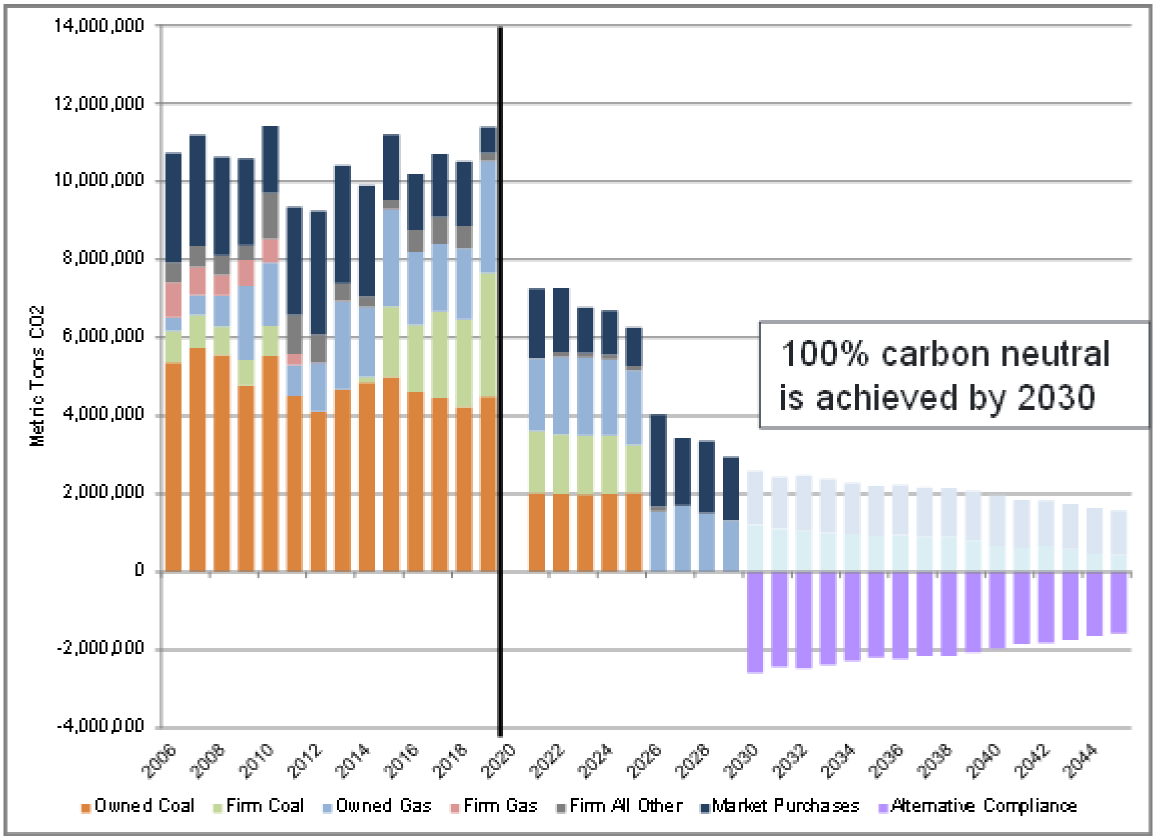


Figure 8-17, below, shows the Mid Scenario portfolio emissions by resource type. There is a direct relationship between emissions and the dispatch of thermal plants. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will decrease further with a lower projected economic dispatch of thermal resources as well the exit of Colstrip 3 & 4 and Centralia from the portfolio. With the resource retirements and forecasted drop in dispatch, total portfolio emissions decrease by over 70 percent from 2019 to 2029. Using alternative compliance mechanisms, the portfolio achieves carbon neutrality from 2030 through to 2045.

Figure 8-17: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions for the Mid Scenario Portfolio



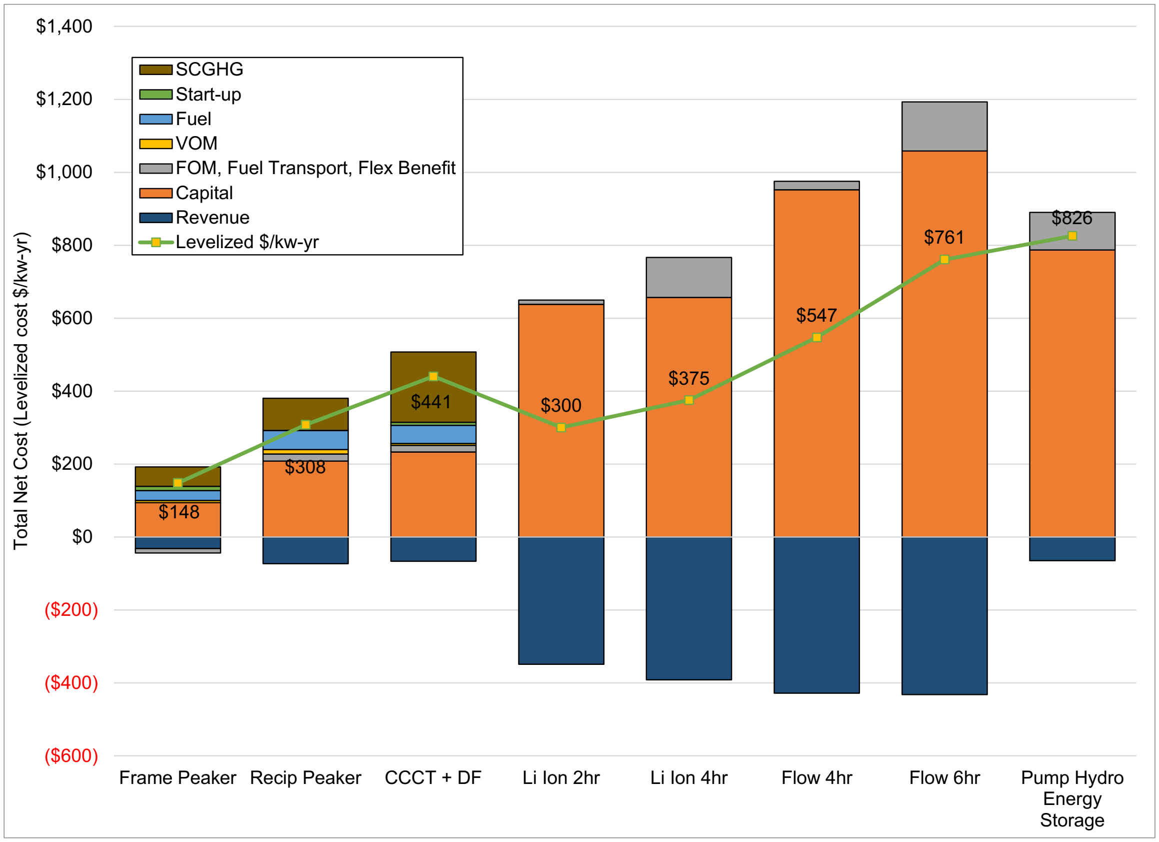
Levelized Cost of Capacity

The levelized costs for peakers, baseload natural gas plants and energy storage resources were evaluated using the Mid Scenario assumptions for electric price, natural gas price and demand to better understand how the resources compare during resource selection. The levelized cost of capacity is based on the peak capacity value of a resource. For example, the nameplate of a 2-hour lithium-ion battery is 25 MW, but it has an ELCC[4] of 12.4 percent, so the peak capacity value is 3.1 MW. (The total cost of the lithium-ion battery is divided by 3.1 MW instead of the 25 MW, which is why it has a high levelized cost of capacity.) When calculating the levelized cost of capacity for new peakers and baseload natural gas plants, the SCGHG is added to the total cost; this increased the levelized cost of capacity for frame peakers from $95 to $148. Figure 8-18

4 / The effective load carrying capacity (ELCC) of a resource represents the peak capacity credit assigned to that resource. More information on ELCC can be found in Chapter 7.

compares the net cost of capacity for peakers, baseload natural gas plants and energy storage resources.

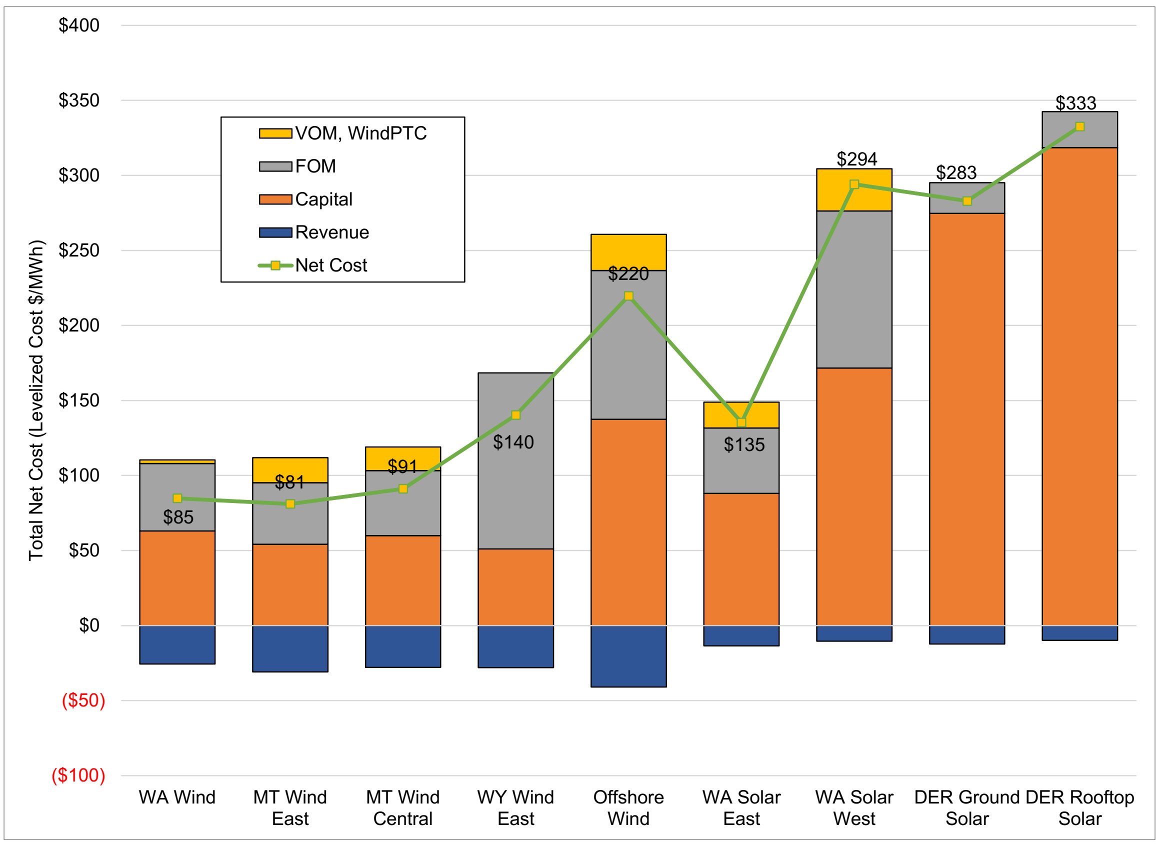
Figure 8-18: Net Cost of Capacity in the Mid Scenario Portfolio Model



Levelized Cost of Energy

The levelized costs of energy for wind and solar resources were also evaluated using the Mid Scenario assumptions to better understand how the resources compare during resource selection. The costs are calculated based on energy and do not account for any peak capacity contribution. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Even though Wyoming wind is higher cost because of transmission costs, it has a high peak capacity credit and provides other value to the portfolio. Given transmission constraints, resources outside of the Pacific Northwest region will be limited. After Montana and Wyoming wind, eastern Washington utility-scale solar is the next lowest cost resource. Figure 8-19 illustrates the levelized costs of renewable resource to meet CETA.

Figure 8-19: Wind and Solar Cost Components, Mid Scenario Portfolio



7. SENSITIVITY ANALYSIS RESULTS

Portfolio sensitivity analysis is an important form of risk analysis that helps PSE understand how specific assumptions can change the mix of resources in the portfolio and affect portfolio costs. This section provides the results and detailed analysis for each sensitivity. Additional results, including year-by-year resource timelines, cost breakdowns and emissions data are provided in Appendix H.

Future Market Availability

A. Renewable Overgeneration Test

In the Mid portfolio there were 0.23 percent of load (355 hours) of overgeneration in 2030 and 10 percent of load (4,000 hours) in 2045. This sensitivity tests the costs and portfolio changes to eliminate the overbuild of renewable generation observed in the Mid portfolio. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales to reduce cost of meeting CETA.

Baseline: PSE can sell 1,500 MW of energy to the Mid-C market at any given hour, subject only to transmission availability.
Sensitivity > PSE cannot sell any energy to the Mid-C market.

KEY FINDINGS. Prohibiting sales to the Mid-C market reduces renewable overgeneration by eliminating market sales and increasing battery energy storage so that the generation can be stored instead. Though renewable generation still occurs in Sensitivity A, it is reduced by 10 percent consistent with the 10 percent overbuild of generation in the Mid Scenario. Wind capacity is reduced, and the remaining renewable generation is from increased solar builds. This portfolio costs almost $1.6 billion more than the Mid portfolio by adding more battery energy storage, but only reduced the overgeneration by 3 percent by 2045. Figure 8-20 compares the amount of renewable overgeneration in the Mid Scenario and Sensitivity A portfolios. In the Mid Scenario portfolio, renewable overgeneration can provide value through sales. In Sensitivity A, without the ability to sell excess energy, the model can only curtail that production or use it to charge battery resources; once the battery resources are at capacity, there is no option left but to curtail the energy. The market is an effective way to reducing cost.

Figure 8-20: Renewable Overgeneration – Mid Scenario and Sensitivity A

	2030			2045		
Portfolio	Hours of Over-generation	MWh of Over-generation	% of total load with conservation	Hours of Over-generation	MWh of Over-generation	% of total load with conservation
Mid Scenario	355	53,946	0.23%	4,330	3,021,777	10.6%
Sensitivity A	29	1,495	0.01%	3,396	2,063,604	7.21%

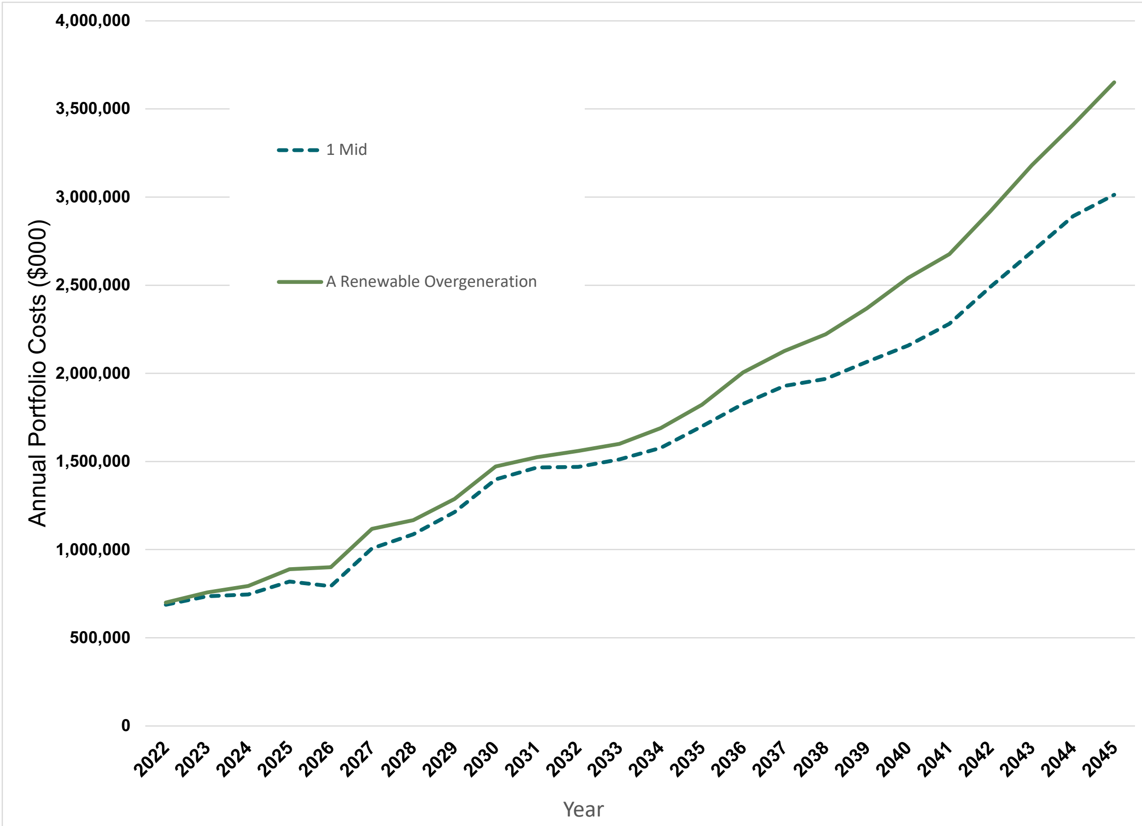
ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid portfolio. The only difference between Sensitivity A and the Mid Scenario is PSE's ability to sell energy to the Mid-C market, which is removed in Sensitivity A.

ANNUAL PORTFOLIO COSTS. Figures 8-21 and 8-22 illustrate the breakdown of costs between the Mid Scenario and Sensitivity A portfolios. Sensitivity A is higher cost overall than the Mid portfolio, and costs begin to diverge at a greater pace as sensitivity A invests heavily in the energy storage necessary to store the renewable generation that cannot be sold to the market. .

Figure 8-21: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity A

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
A	Renewable Overgeneration test	$17.11	$4.45	$21.55	$0.93

Figure 8-22: Annual Portfolio Costs – Mid Scenario and Sensitivity A



RESOURCE ADDITIONS. Figure 8-23 compares the nameplate capacity additions of the Sensitivity A and Mid Scenario portfolios. Sensitivity A builds more nameplate capacity than the Mid Scenario, and the distribution of resources shifts some capacity from wind generation to solar and storage. No pumped hydro storage is built, but investment in hybrid resources and standalone battery resources increases. Conservation reaches Bundle 11 in this sensitivity. No PSE resources, new or existing, are retired in this sensitivity.

Figure 8-23: Portfolio Additions– Mid Scenario and Sensitivity A, Renewable Overgeneration

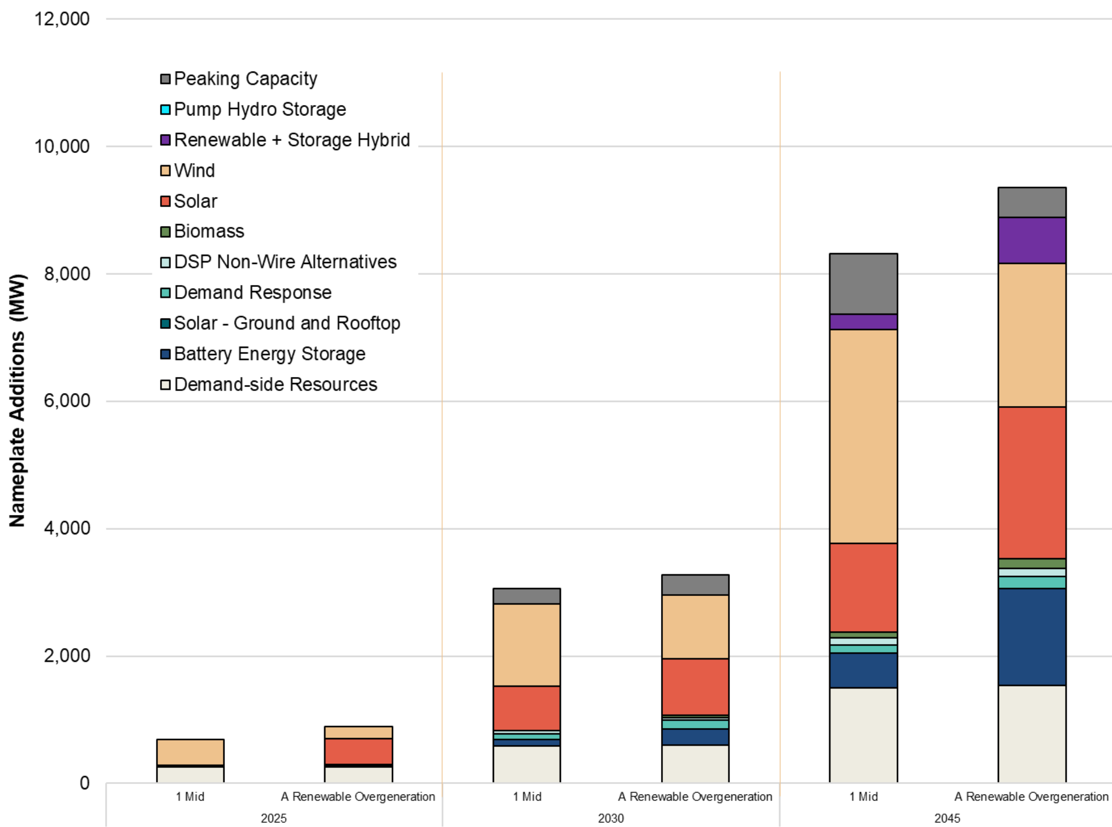


Figure 8-24: Portfolio Additions by 2045 – Mid Scenario and Sensitivity A, Renewable Overgeneration

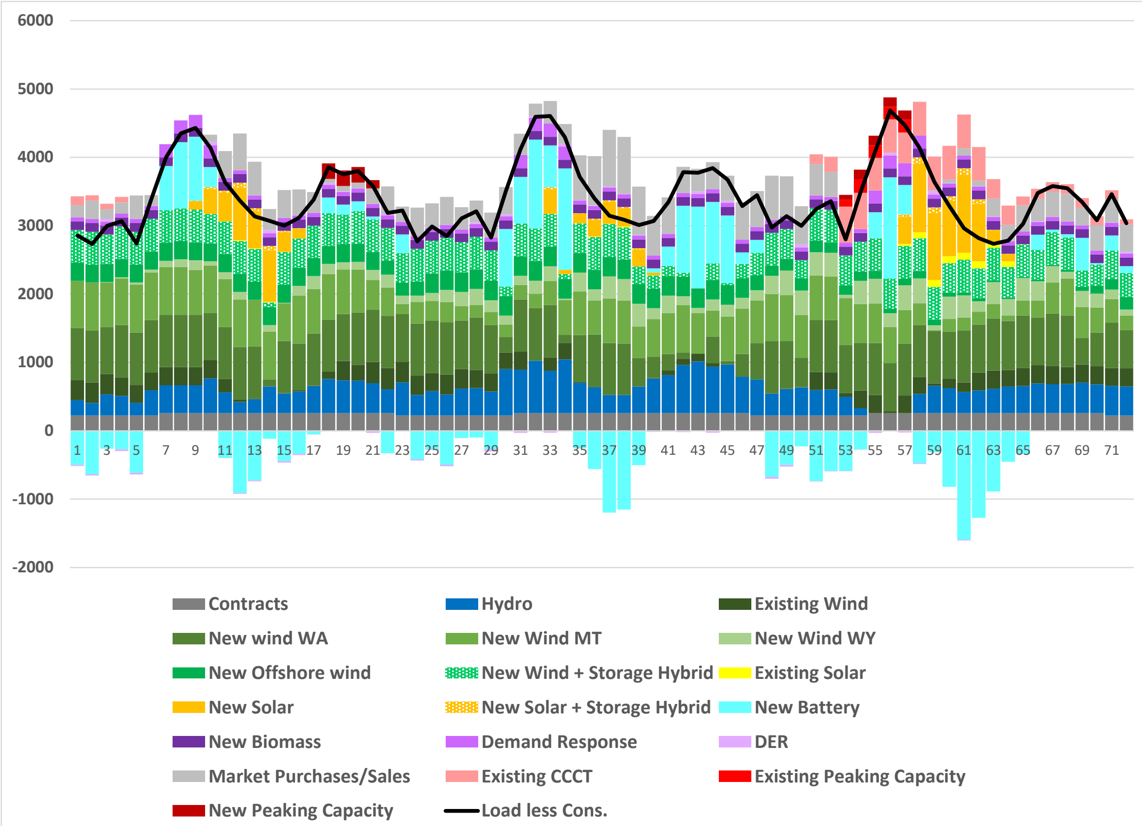
Resource Additions by 2045	1 Mid	A Renewable Overgeneration
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	192 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,788 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,388 MW
Wind	3,350 MW	2,250 MW
Renewable + Storage Hybrid	250 MW	725 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW[1]

NOTE
1. Includes 237 MW of recip peakers and 237 MW of frame peakers

PEAK NEED. In 2045, the peak capacity behavior of the new resources changes in this sensitivity. Figure 8-25 shows the hourly dispatch of resources in Sensitivity A during peak demand for 2045. Resources generating above the black line are producing power in excess of load from mostly market purchases (gray bars) and some new and existing natural gas generation (maroon and pink bars) mostly to charge batteries (blue bars below zero).

During periods of peak demand, there is not enough generation to both meet customer demand and charge batteries. In order for the battery to meet energy need during peaks, the batteries must be charged. Without market for charging the batteries as in this sensitivity, the model uses natural gas generation to charge the batteries.

Figure 8-25: 2045 Peak Demand Period of Sensitivity A, December 28-30, 2045



The relationship between market purchases and battery activity can be seen by examining the times at which the market purchases are occurring. For Sensitivity A, Figure 8-26 shows the percentage of hours each month where market purchases are being made by PSE in the year 2045. Market purchases are made consistently throughout the winter to assist the generating resources. During off-peak hours, market purchases provide energy for the batteries to charge; during peak hours when the batteries are discharging, market purchases help to meet demand.

Figure 8-26: Percentage of Each Month Where Market Purchases are Being Made in Each Hour for Sensitivity A, 2045

All Purchase Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0:00	81%	83%	87%	27%	0%	0%	13%	48%	83%	71%	67%	100%
1:00	81%	83%	84%	27%	0%	0%	13%	48%	90%	71%	67%	100%
2:00	81%	86%	84%	27%	0%	0%	13%	48%	83%	71%	67%	100%
3:00	81%	83%	81%	23%	0%	0%	13%	42%	83%	71%	67%	100%
4:00	81%	86%	77%	17%	0%	0%	10%	48%	83%	74%	63%	87%
5:00	84%	76%	77%	20%	0%	0%	6%	42%	87%	71%	63%	87%
6:00	84%	62%	61%	17%	0%	0%	3%	52%	83%	71%	67%	81%
7:00	81%	69%	65%	3%	0%	0%	10%	48%	73%	68%	60%	77%
8:00	84%	79%	58%	10%	0%	0%	6%	61%	70%	71%	60%	87%
9:00	84%	76%	68%	10%	0%	0%	6%	65%	70%	68%	57%	94%
10:00	81%	79%	71%	10%	0%	0%	13%	61%	67%	68%	57%	97%
11:00	77%	79%	68%	10%	0%	0%	19%	61%	70%	68%	60%	97%
12:00	77%	79%	65%	17%	0%	0%	19%	65%	70%	68%	60%	97%
13:00	77%	79%	71%	13%	3%	0%	23%	58%	70%	68%	60%	97%
14:00	81%	79%	71%	7%	3%	0%	10%	58%	70%	65%	63%	97%
15:00	81%	79%	71%	10%	3%	3%	13%	52%	70%	68%	67%	97%
16:00	84%	79%	61%	3%	0%	0%	0%	48%	70%	71%	73%	97%
17:00	84%	76%	68%	10%	3%	0%	3%	23%	63%	71%	70%	97%
18:00	84%	76%	68%	17%	3%	3%	19%	39%	60%	74%	73%	94%
19:00	84%	83%	68%	17%	6%	3%	26%	32%	63%	74%	70%	94%
20:00	87%	76%	71%	17%	6%	3%	23%	39%	73%	81%	67%	97%
21:00	84%	79%	77%	17%	6%	7%	26%	52%	90%	77%	73%	97%
22:00	81%	83%	77%	17%	6%	7%	19%	45%	93%	74%	73%	97%
23:00	81%	83%	77%	17%	6%	3%	19%	45%	90%	77%	73%	97%

B. Reduced Market Reliance

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy model. Sensitivity B provides insight into navigating a market with reduced availability of market purchases by examining how to optimize a portfolio that is limited by these conditions.

Baseline: PSE can make market purchases at the hourly power price, subject to the transmission limits to the Mid-C Market. PSE currently uses these purchases to meet demand at peak demand hours.

Sensitivity B > PSE's transmission access to the Mid-C Market is reduced to 1,300 MW in 2023, 1,100 MW in 2024, 900 MW in 2025, 700 MW in 2026, and 500 MW in 2027 and thereafter during November-February and June-August. Transmission access remains the same for the months March-May and September-October, as well as the year 2022.

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KEY FINDINGS. To compensate for reduced market purchases, sensitivity B overbuilds renewable resources to charge batteries and builds 1,495 of peaking capacity by 2031, nearly double the amount in the Mid Scenario. This sensitivity builds the same amount of Washington wind as the Mid Scenario, but on an accelerated timeline. By 2045, increased storage builds play a larger role in meeting peak demand. Peaking capacity and CCCT thermal generation continue to assist in meeting peak demand, but renewable overgeneration is the primary energy source for batteries.

ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid Scenario portfolio, except for changes to Mid-C market access. The amount of Mid-C Market transmission access in Sensitivity B, which defines the amount of market purchases PSE can make, is seen in Figure 8-27.

Figure 8-27: Transmission Limits to the Mid-C Market in Sensitivity B in MW

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

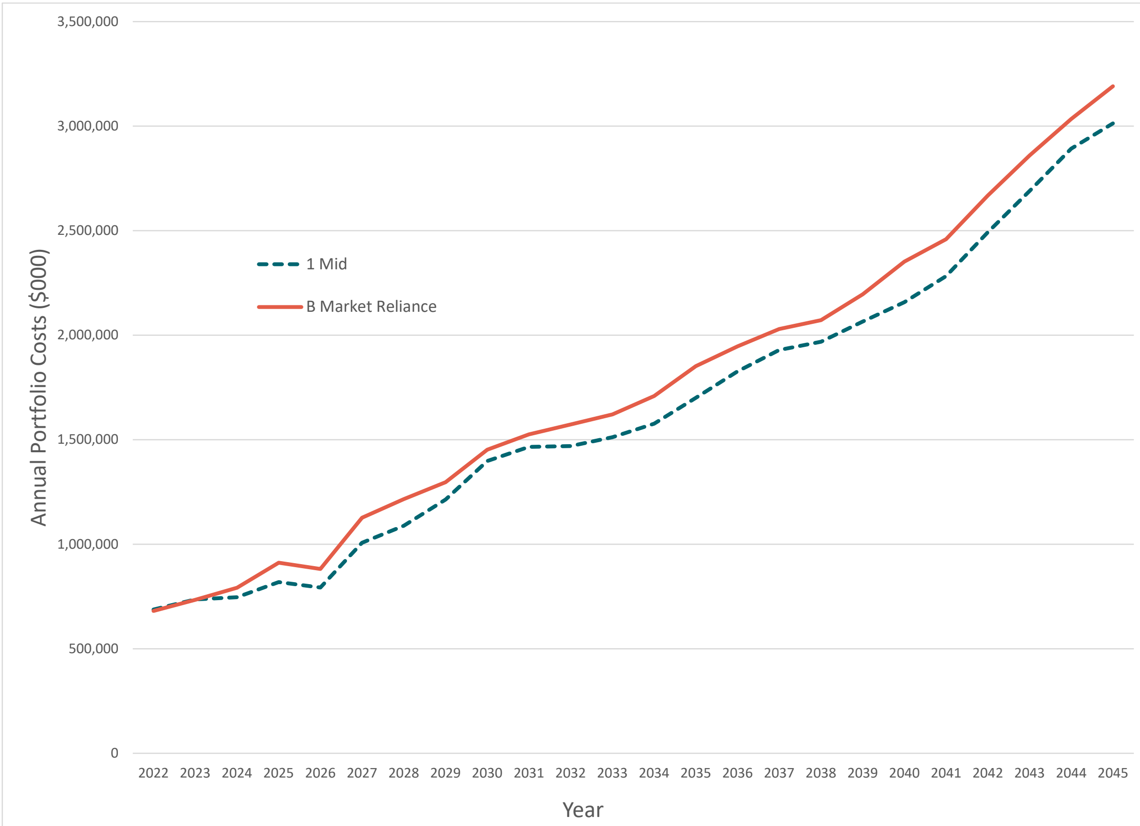
ANNUAL PORTFOLIO COSTS. Figures 8-28 and 8-29 illustrate the breakdown of costs between the Mid Scenario and Sensitivities B. As expected, increasing restrictions to market purchases increases portfolio costs. This sensitivity builds more resources in the early years of the simulation so the annual portfolio costs start diverging as early as 2023.

The final builds of the Sensitivity B and the Mid Scenario portfolios are similar, with more peaking capacity and an accelerated installation of Washington wind in Sensitivity B. As a result, the annual costs of Sensitivity B track with the costs of the Mid Scenario, with the earlier installation timeline and increased peaking capacity raising the overall price.

Figure 8-28: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity B

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
B	Reduced Market Reliance	$16.57	$5.19	$21.76	$1.35

Figure 8-29: Annual Portfolio Costs – Mid Scenario and Sensitivity B



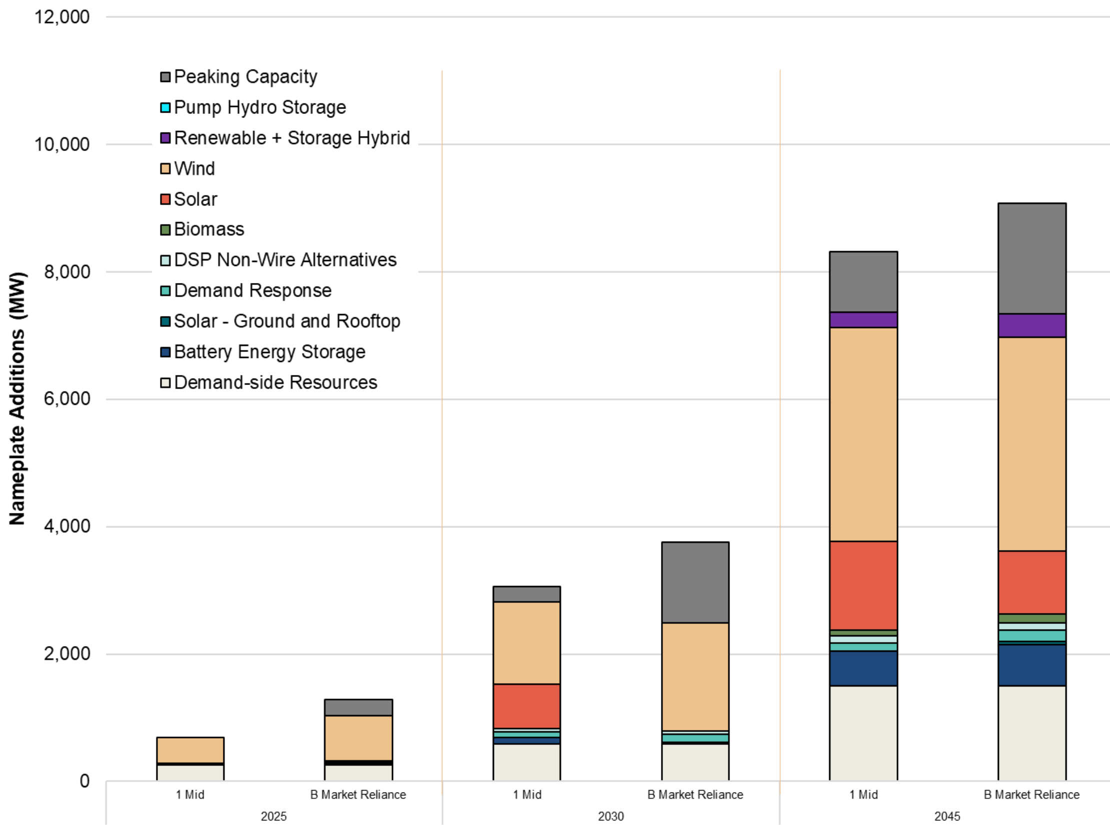
RESOURCE ADDITIONS. Figure 8-30 compares the nameplate capacity additions of the Mid Scenario and Sensitivity B.

Sensitivity B invests in the same amount of demand-side resources as the Mid Scenario (Bundle 10). With limited access to the market, this sensitivity invests heavily in peaking capacity and accelerates the construction of Washington wind resources compared to the Mid Scenario. In the later years of the simulation, storage resources are still needed, but they are delayed due to the high capacity of thermal resources being installed in the early years. Without market purchases to bridge the gap between renewable generation and demand, the portfolio leans heavily on increased peaking capacity builds. Increased peaking capacity is the most prominent difference between the Mid Scenario and Sensitivity B, indicating that the model selects thermal generation as the least cost resource to replace the market purchases. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict.

Figure 8-30: Portfolio Additions – Mid Scenario and Sensitivity B, Reduced Market Reliance

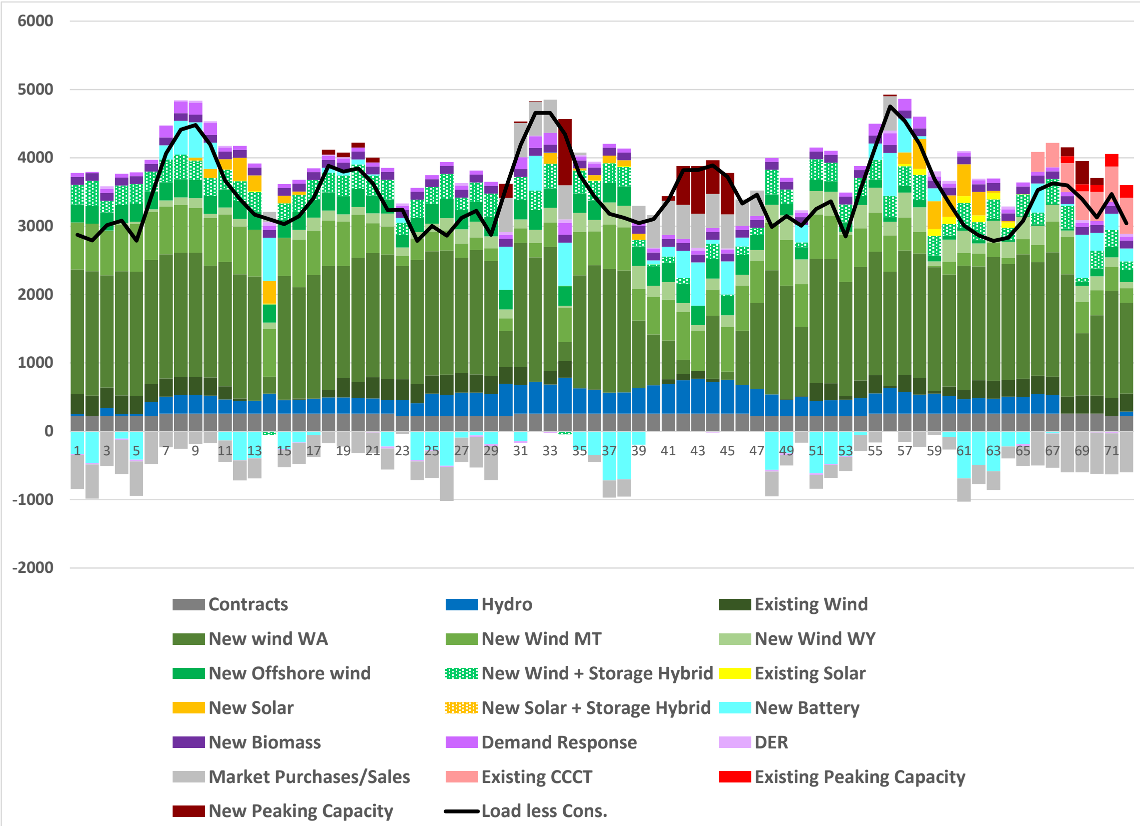
Resource Additions by 2045	1 Mid	B Reduced Market Reliance
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	650 MW
Solar – Ground and Rooftop	0 MW	50 MW
Demand Response	123 MW	173 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,480 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	995 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,732 MW

Figure 8-31: Portfolio Additions by 2045 – Mid Scenario and Sensitivity B, Reduced Market Reliance



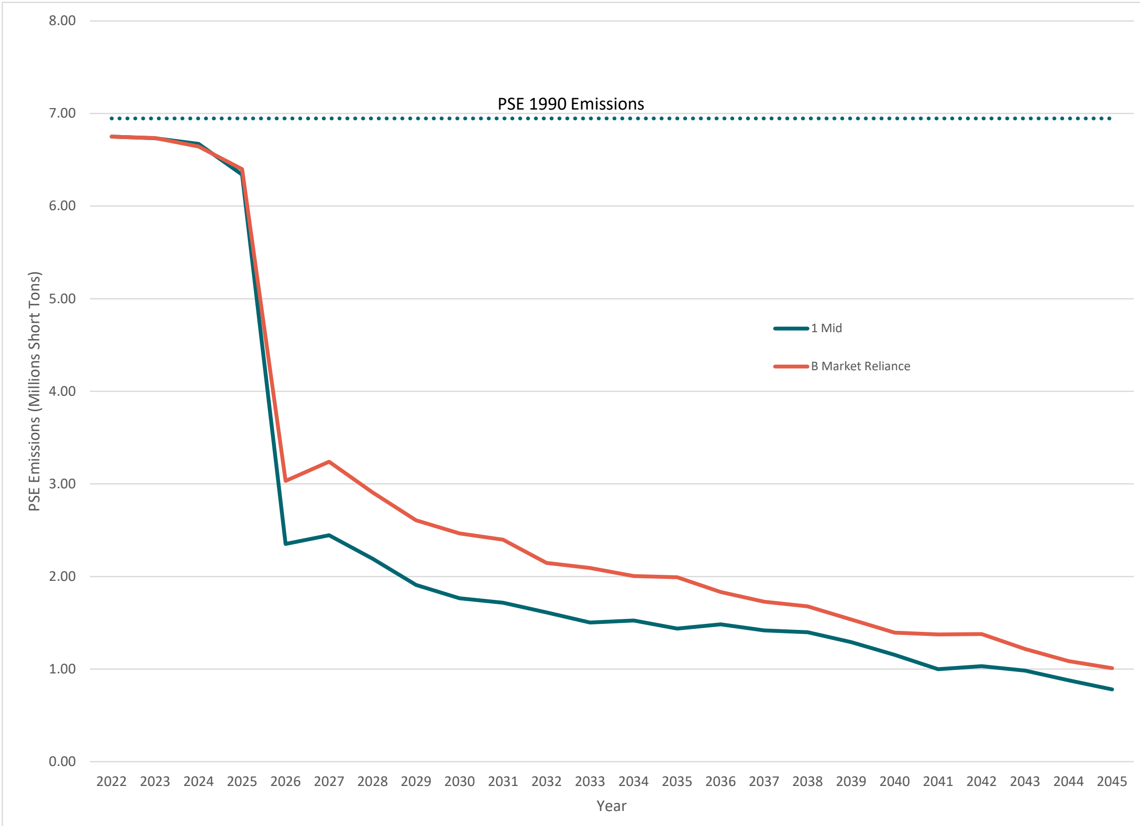
PEAK NEED AND EMISSIONS. The peak demand period of Sensitivity B is shown in Figure 8-32. Portfolio B uses renewable overbuilds as the main method of charging the batteries (blue bars). The excess energy, generation above the black lines, provides value through market sales (gray bars below zero) and the charging of batteries (blue bars below zero) during off-peak hours. Market purchases are still available in a limited capacity, and are still used to assist in meeting demand when renewable generation is not sufficient. Thermal generation also continues to play a role in meeting peak demand. In Figure 8-32, thermal generation is still needed when there is not enough energy from renewable resources, batteries, or demand response to meet demand as can be seen in the hours 30, 34, 40-45, and 68-72.

Figure 8-32: 2045 Peak Demand Period of Sensitivity B, December 28-30, 2045



EMISSIONS. Use of thermal generation to compensate for the reduction of market purchases increases the emissions of PSE resources in sensitivity B. Figure 8-33 compares the yearly emissions of PSE resources (without market purchases) to the Mid Scenario.

Figure 8-33: Annual Emissions of PSE Resources – Mid Scenario and Sensitivity B (market purchases are not included)



Transmission Constraints and Build Limitations

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

Baseline: The Mid Scenario assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a maximum of 1,500 MW of Mid-C market access and build limitations for Montana, Idaho and Wyoming based resources.
Sensitivity > Sensitivity C assumes the more restrictive transmission constraints described by Tier 2, which includes those described in the baseline plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. Tier 2 transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon compared to the Mid Scenario portfolio. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. Sensitivity C pairs the distributed solar resources with battery storage projects to better serve load when solar generation is not available. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

ASSUMPTIONS. Sensitivity C assumes transmission capacity outside of PSE's service territory will be limited to 3,070 MW. Figure 8-34 summarizes the Tier 2 transmission capacity assumptions for each resource group region. (A complete description of the four transmission tiers and resource group regions is provided in Chapter 5.)

Figure 8-34: Sensitivity C Transmission Constraints – Tier 2

Resource Group Region	Tier 2
PSE territory	unconstrained
Eastern Washington	675
Central Washington	625
Western Washington	100
Southern Washington/Gorge	705
Montana	565
Idaho / Wyoming	400
TOTAL	**3,070**

Several additional constraints were incorporated into the optimization to encourage realistic resource selections. The forecast of customer-owned, residential solar projects was adjusted to reflect increased adoption of residential solar and matches the Conservation Potential Assessment Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E. This assumption aligns with a portfolio focused on distributed energy resources.

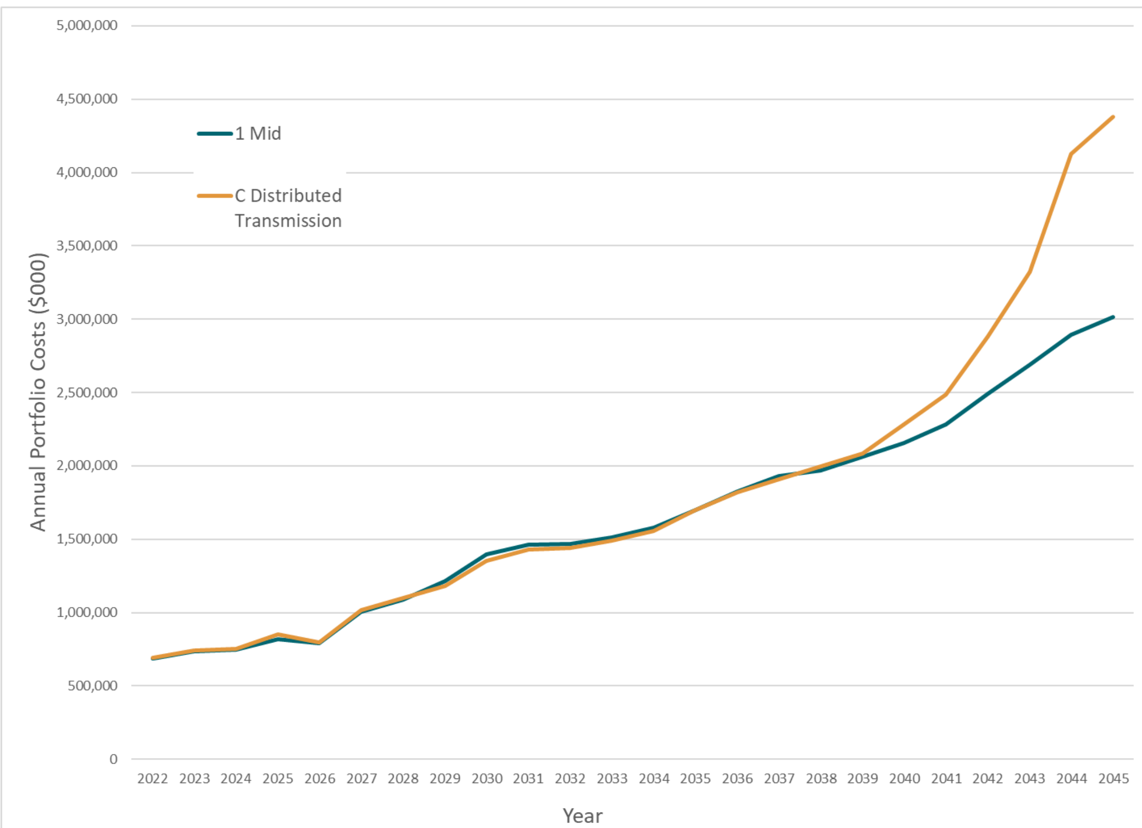
PORTFOLIO COSTS. Compared to the Mid Scenario portfolio, the Sensitivity C portfolio is more expensive over the modeling time horizon as shown in Figure 8-35. Distributed solar resources cost substantially more to install than utility-scale solar resources, resulting in increased generic resource revenue requirements. These increased generic resource revenue requirements are the major driver of the increased portfolio cost.

Figure 8-35: Portfolio Cost Comparison – Mid Scenario and Sensitivity C

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
C	Distributed – Transmission/Build Constraints Tier 2	$16.35	$5.21	$21.56	$0.94

Until year 2039, the Mid Scenario and Sensitivity C portfolios project similar annual revenue requirements as shown in Figure 8-36. After year 2039, Sensitivity C exhausts all available transmission outside of PSE's service territory and is forced to select more costly distributed solar resources, resulting in a sharp increase in annual revenue requirement in the later years.

Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity C



RESOURCE ADDITIONS. Sensitivity C is marked by a transition from utility-scale wind and solar resources in central, eastern and southern Washington to distributed solar resources within the PSE service territory. Given that the effective load carrying capability of distributed solar resources is low, battery storage resources are added to the portfolio to meet load during peak hours. Biomass resources within the PSE service territory are also added to help accommodate base loads and meet CETA energy targets. New peaking capacity resource additions remain unchanged from the Mid Scenario.

Sensitivity C selects conservation Bundle 11 which is more conservation than selected in the Mid Scenario (Bundle 10). The increased conservation is due to the increased resource costs of distributed solar resources.

These resource build decisions are summarized in Figures 8-37 and 8-38.

Figure 8-37: Portfolio Additions – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

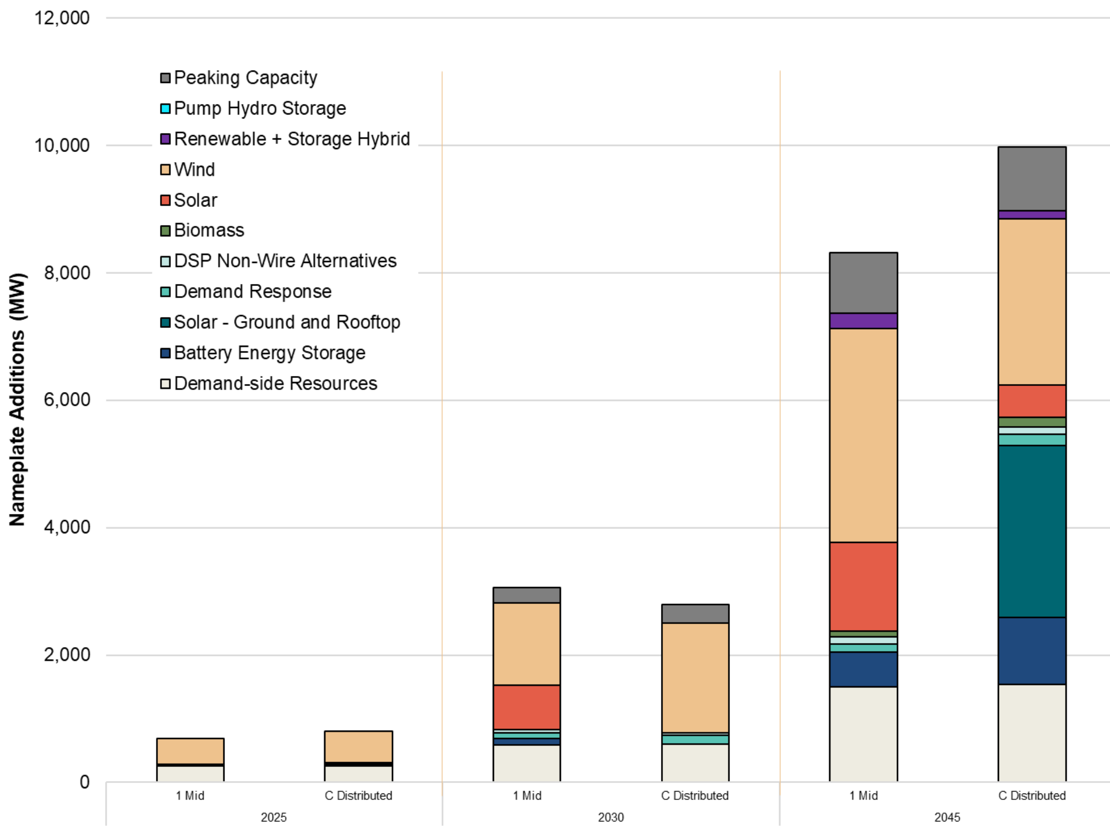


Figure 8-38: Portfolio Additions by 2045 – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

Resource Additions by 2045	1 Mid	C Distributed Transmission Tier 2
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,050 MW
Solar - Ground and Rooftop	0 MW	2,700 MW
Demand Response	123 MW	178 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	3,265 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	500 MW
Wind	3,350 MW	2,615 MW
Renewable + Storage Hybrid	250 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,003 MW

OTHER FINDINGS. Distributed solar, ground mount and rooftop, is capable of meeting a significant portion of load. As shown in Figure 8-39, distributed solar contributes approximately 13 percent of total energy load in 2045. However, distributed solar is a poor resource for meeting peak capacity need, because it has an effective load carrying capability of less than 2 percent. This means that other resources are needed to provide capacity during peak need events. Sensitivity C selected peaking capacity resources to meet this need, so slightly more peaking resource capacity was added to Sensitivity C compared to the Mid Scenario portfolio. Furthermore, those peaking capacity resources were dispatched more often, resulting in increased emissions for Sensitivity C in the later years of the modeling horizon. In 2045, the Mid Scenario generated 0.78 million tons of greenhouse gases (GHGs), while Sensitivity C generated 1.00 million tons of GHGs. Figure 8-40 compares the emissions from the Mid Scenario and Sensitivity C portfolios in millions short tons.

Figure 8-39: Annual Energy Production by Resource Type (aggregated) – Sensitivity C

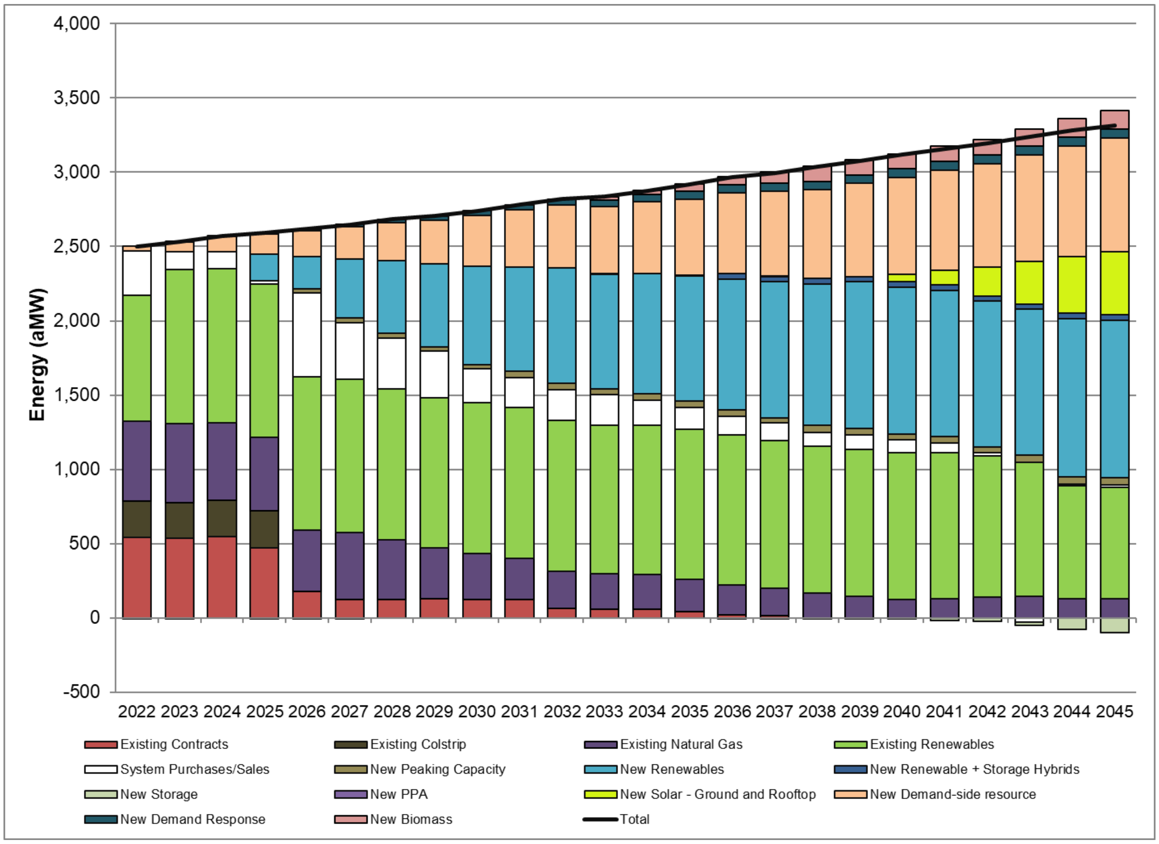
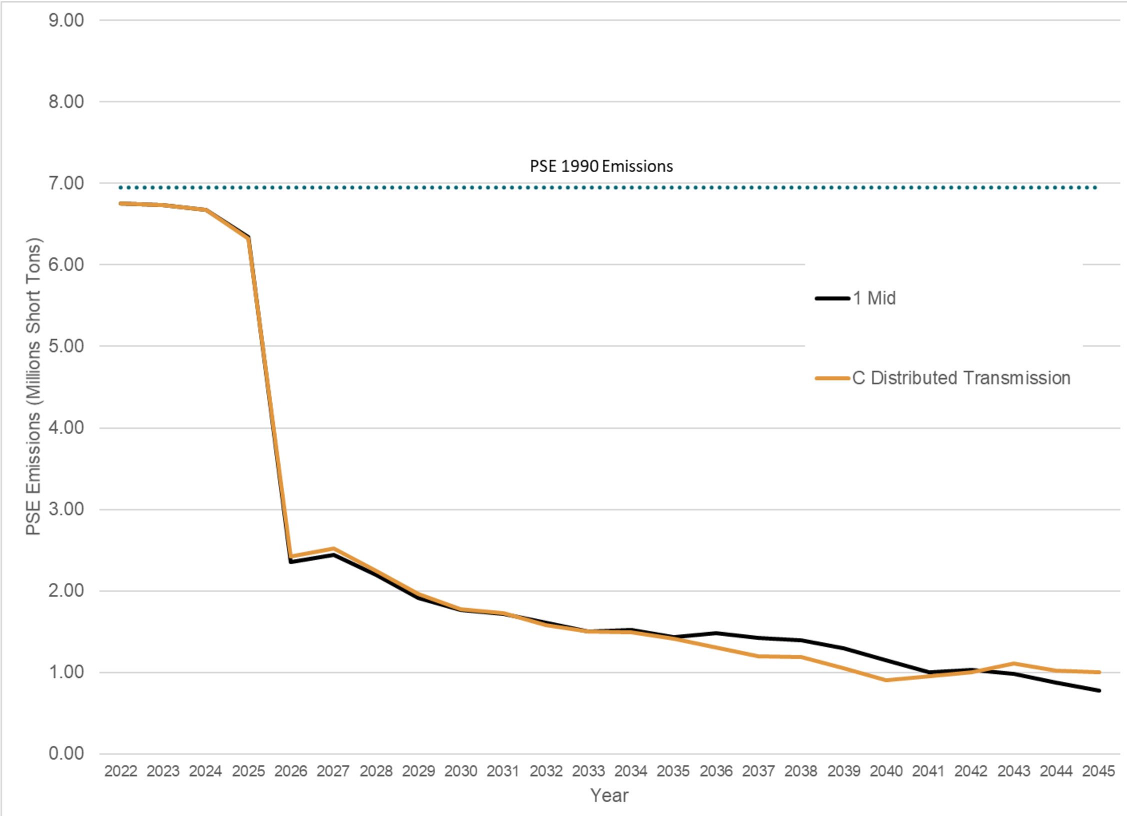


Figure 8-40: Direct Portfolio Emissions – Mid Scenario and Sensitivity C



D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined four "Tiers" of transmission availability, which increase transmission capacity over time. This sensitivity ramps in transmission availability over the modeling horizon.

Baseline: The baseline assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a limit of 1,500 MW of purchases from the Mid-C market and build limitations for Montana, Idaho and Wyoming based resources. **Sensitivity >** Sensitivity D assumes that transmission constraints increase over time, modeling Tier 1 constraints through 2025, Tier 2 through 2030, Tier 3 through 2035 and Tier 0 (generally unconstrained) after 2035. PSE's system is subject to more restrictive transmission constraints, including those described in the baseline, plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. The Tiered transmission constraints modeled in Sensitivity D had relatively little impact on the portfolio composition compared to the Mid Scenario. Early in the modeling horizon, Sensitivity D tends to select wind more often than solar compared to Mid Scenario. By the end of the modeling horizon, most resource builds are near those in the Mid Scenario. Costs and GHG emissions are also in line with those in the Mid Scenario. This suggests that transmission constraints (until the year 2035) have little influence on resource acquisition decisions. A similar result was observed in Sensitivity C.

ASSUMPTIONS. Sensitivity D assumes that transmission capacity availability outside of PSE's service territory ramps in over time. Figure 8-41 summarizes the transmission capacity assumptions for each Tier and associated timeframe. (See Chapter 5 for a complete description of the four transmission tiers and resource group regions.)

Figure 8-41: Sensitivity D Transmission Constraints

	Added Transmission (MW)			
Resource Group Region	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**
Modeling Timeframe	**2035-2045**	**2022-2025**	**2025-2030**	**2030-2035**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

PORTFOLIO COSTS. The Sensitivity D portfolio is slightly more expensive over the modeling time horizon compared to the Mid Scenario portfolio, as shown in Figure 8-42. However, the 24-year levelized cost difference is less than $30 million, which suggests that transmission limitations do not strongly constrain resource builds over the 2022 to 2035 time horizon.

Figure 8-42: Portfolio Cost Comparison – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
D	Transmission/Build Constraints – Time-delayed (Option 2)	$15.54	$5.11	$20.65	$0.03

RESOURCE ADDITIONS. Resource additions for Sensitivity D are very similar to the Mid Scenario. This similarity suggests that transmission constraints (until the year 2035) do not have a significant impact on resources build decisions. Sensitivity D shifts away from eastern Washington solar and toward Washington wind due to wind's higher capacity factor, which results in more energy production early in the planning horizon. Sensitivity D also builds slightly more and longer-duration storage than the Mid Scenario. However, the increased storage builds in Sensitivity D occur after 2035, once transmission constraints have been lifted, which suggests the storage decisions were a result of the early focus on wind instead of solar. By 2024, wind and solar builds in Sensitivity D are nearly equal the Mid Scenario.

Sensitivity D selects conservation Bundle 11, which is more conservation than selected in the Mid Scenario (Bundle 10).

These resource build decisions are summarized in Figures 8-43 and 8-44.

Figure 8-43: Portfolio Additions – Mid Scenario and Sensitivity D, Transmission Build Constraints – Time Delayed (Option 2)

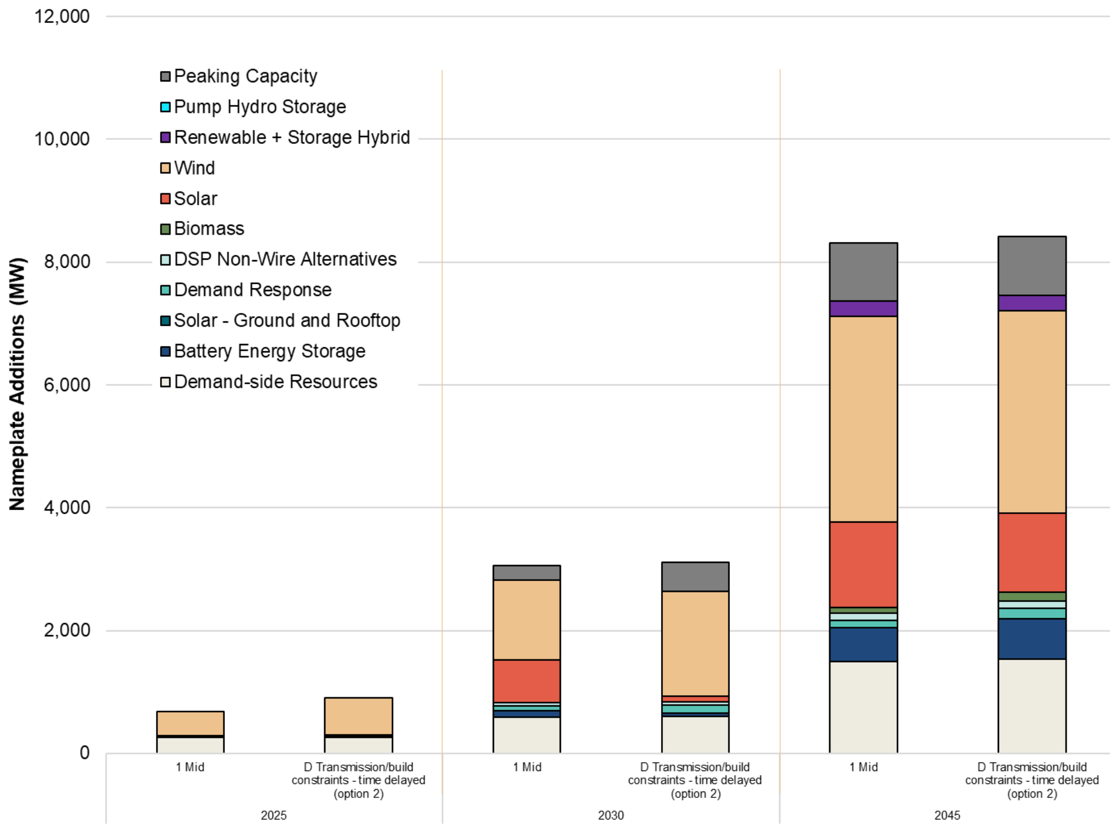


Figure 8-44: Portfolio Additions by 2045, Sensitivity D – Transmission Build Constraints – Time delayed (Option 2)

Resource Additions by 2045	1 Mid	D Transmission Build Constraints – Time delayed (Option 2)
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	650 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	180 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,730 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,295 MW
Wind	3,350 MW	3,300 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity examines the impact on portfolio costs when the capacity of firm transmission purchased with new resources is less than the nameplate capacity of the generating resource.

Baseline: New resources are acquired with transmission capacity equal to their nameplate capacity.

Sensitivity > New resources are acquired with less transmission capacity than nameplate capacity.

KEY FINDINGS. The benefit from contracting firm transmission less than the nameplate capacity of a renewable resource is highly site specific. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due the significant portion of time that wind resources spend at or near nameplate capacity (i.e., rated power).

ASSUMPTIONS. This sensitivity examines the trade-off between investing in the cost of firm transmission versus the cost of having to replace power lost to transmission curtailment because transmission less than nameplate capacity was acquired. This trade-off was calculated for the following generic resource alternatives: Washington wind, Montana wind east, Montana wind central, Wyoming wind east, Wyoming wind west, Idaho wind, utility-scale Washington solar east, utility-scale Wyoming solar east, utility-scale Wyoming solar west and utility-scale Idaho solar.

The annual transmission cost for each resource was calculated using the fixed transmission cost of the resource (provided in Figure 5-25 in Chapter 5) times the nameplate capacity of the resource. The transmission-curtailed energy was calculated as the sum of all hours where the resource production exceeded the transmission limit. For example, a 100 MW wind farm operating at rated power with 10 percent reduced transmission will curtail 10 MWh for a one-hour period (100 MW x 1 h – 100 MW x (1-0.10) x 1 h = 10 MWh).

The replacement cost of transmission-curtailed energy was assumed to be equal to the levelized cost of power for the given resource. PSE acknowledges that these assumptions present a "worst-case scenario" analysis, where it is assumed that all power produced can be used (i.e., production equals demand) and that no short-term transmission may be purchased to supplement long-term firm transmission. While not a comprehensive analysis, this assessment provides a reasonable estimate of potential costs and benefits attributable to reduced transmission sensitivities.

WIND RESULTS. Figure 8-45 shows the trade-off for 200 MW of generic wind resources modeled in the 2021 IRP at various degrees of transmission under-build. Points greater than zero on this plot indicate reduced transmission scenarios that provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (100 percent), therefore at 100 percent, there is no benefit or cost.

The results show that resources with high transmission costs (Wyoming and Idaho wind resources) return the greatest savings. All wind resources indicate at least some benefit in the range of transmission capacity reductions from around 99 percent to 96 percent of nameplate capacity. This is because wind farms typically produce 0 to 3 percent less power than nameplate due to internal electrical line losses. After this point, the trade-off quickly drops below zero for resources with low fixed transmission costs because wind resources often produce close to their rated power. Figure 8-46 shows a typical histogram for a generic wind resource, where the plurality of the generation time is at or above 95 percent net capacity factor. Most often, therefore, when the wind farm is generating power, it is likely to be using all available transmission.

Fixed transmission costs for Idaho and Wyoming resources are more than four times higher than for eastern Washington wind resources. These premium fixed transmission costs are why Idaho and Wyoming wind resources have such a large potential benefit compared to other wind resources.

Figure 8-45: Trade-off as a Function of Transmission Under-build Degree for 200 MW Wind Resources

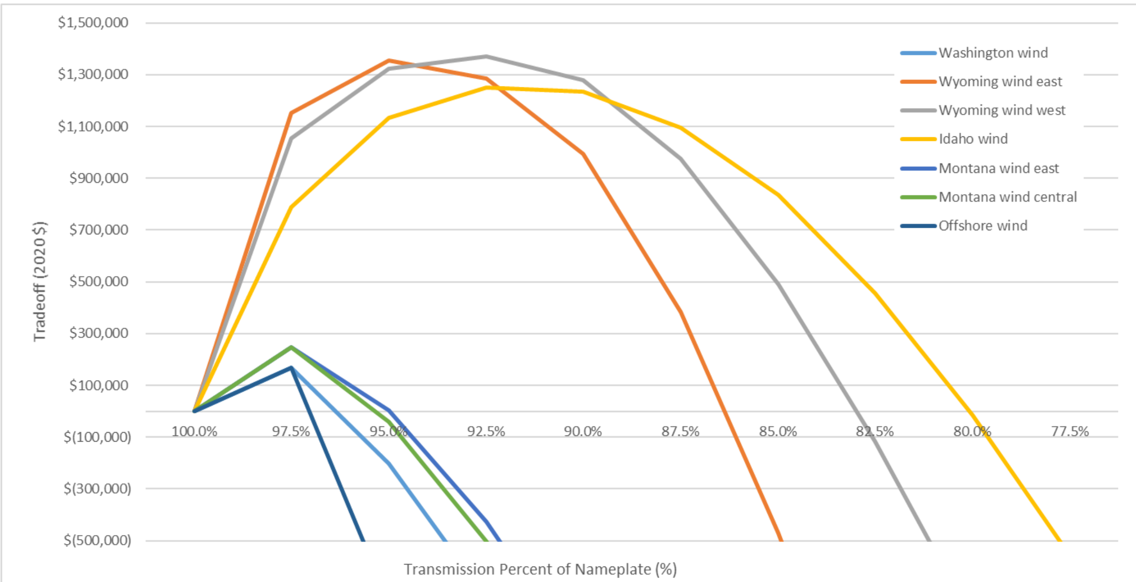
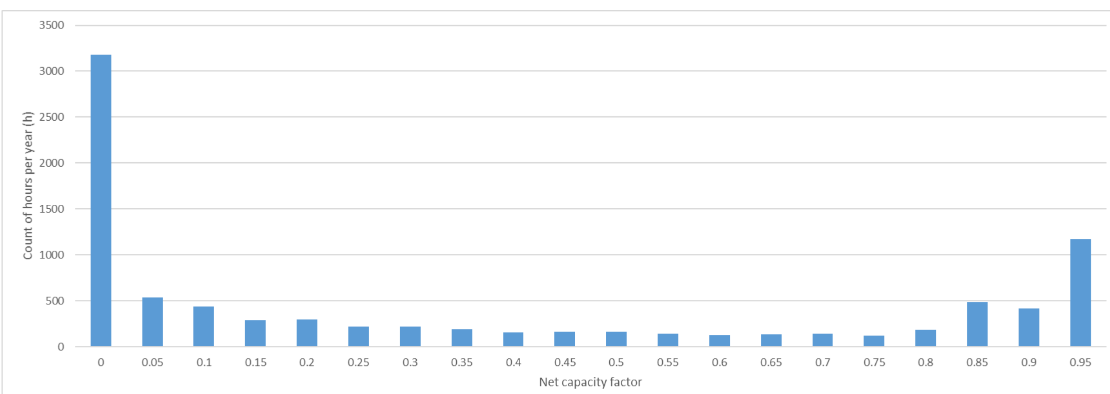


Figure 8-46: Net Capacity Factor Distribution of a Typical Wind Resource



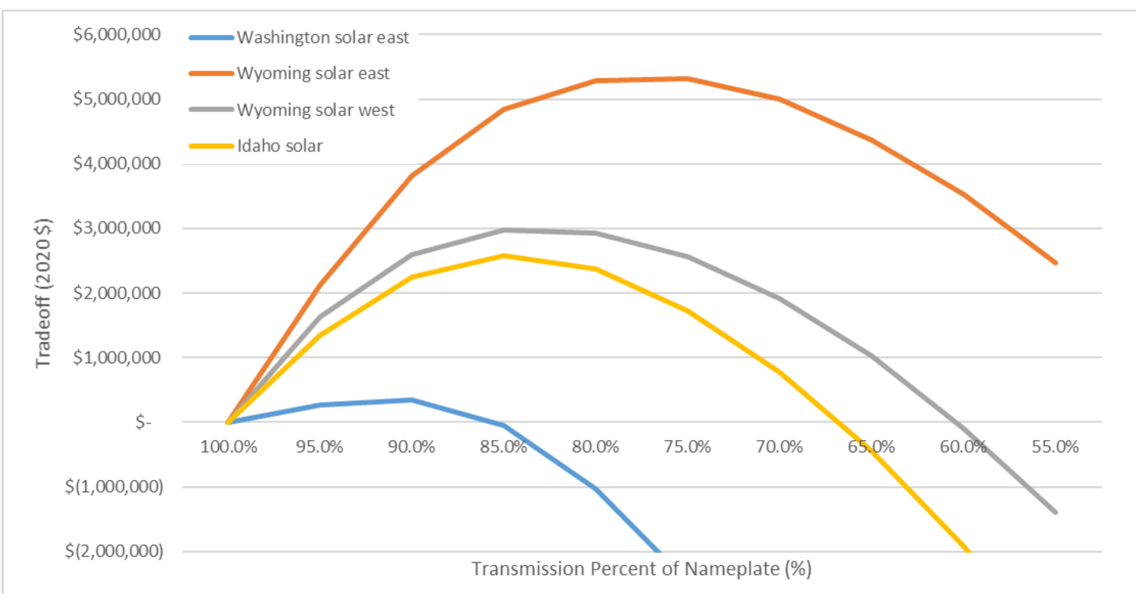
The results of this investigation came as a surprise to PSE. Initial investigations in the 2021 Draft IRP showed very little benefit for all wind resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the results are highly site specific.

PSE will continue to investigate the potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability of resources, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

SOLAR RESULTS. Figure 8-47 shows the trade-off for 200 MW of generic solar resources modeled in the 2021 IRP at various degrees of transmission reduction. Points greater than zero on this plot indicate transmission reduction scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity that equals resource nameplate capacity (100 percent), therefore at 100 percent there is no benefit or cost.

Similar to the wind resources discussed above, the benefit of under-built transmission capacity is highly site specific and strongly correlated to fixed transmission cost. Regions with high fixed transmission costs (Idaho and Wyoming) have significantly more benefit than regions with low fixed transmission costs (eastern Washington).

Figure 8-47: Trade-off as a Function of Transmission Under-build Degree for 200 MW Solar Resources



Similar to the wind results above, the results of the solar investigation came as a surprise to PSE. Initial investigations for the 2021 draft IRP showed very little benefit for all solar resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the circumstances are highly site specific.

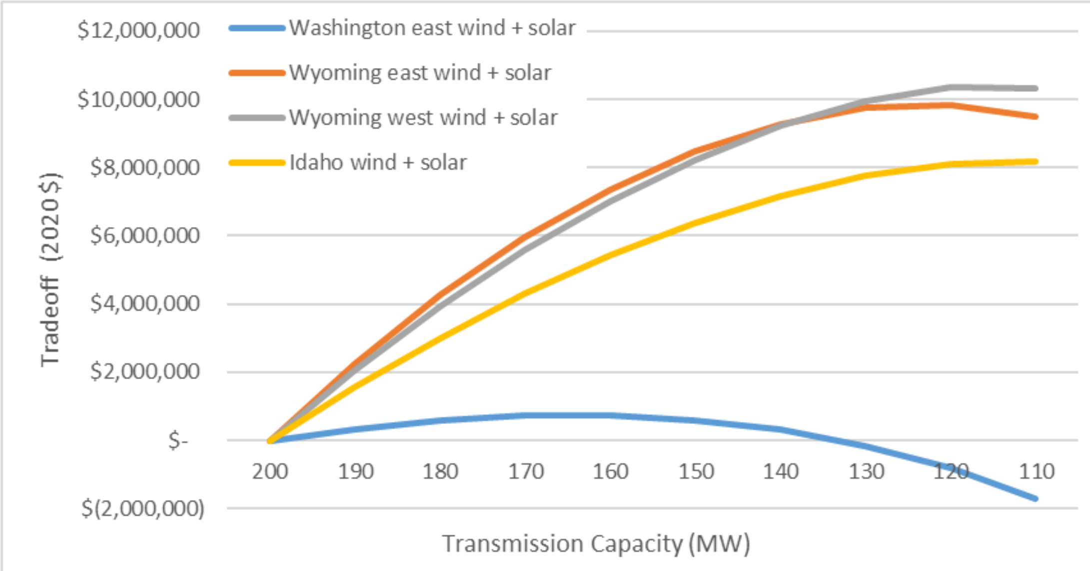
PSE will continue to investigate potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

NEXT STEPS. In addition to the transmission sensitivities described above, PSE also looked at co-locating a wind and solar resource with shared, limited transmission capacity. A complementary relationship appears to exist between the resource pairs assessed. First, wind resources with higher winter production may benefit from co-location with solar resources that have higher summer production. Second, wind resources with higher overnight production may benefit from co-location with solar resources that, by nature, only produce power during the day. Optimizing the amount of transmission to better match the average seasonal and diurnal production of the co-located resources may realize cost savings, as opposed to securing firm transmission for both resources individually.

Figure 8-48 shows the possible benefits of co-locating a 100 MW wind farm with a 100 MW solar farm at various locations. Cost benefits from reducing firm transmission contracts are strongly correlated to fixed transmission cost, as seen in the analysis of individual wind and solar resources. Interestingly, on a dollar-per-megawatt nameplate capacity basis, the benefit of the co-location is even greater than for individual wind or solar resources, which shows a synergistic relationship between co-located wind and solar resources that share transmission capacity.

PSE looks forward to continuing to learn more about benefits of co-located resources in future IRP cycles.

Figure 8-48: Trade-off as a Function of Transmission Capacity for Co-located 100 MW Wind and 100 MW Solar Resources



Conservation Alternatives

F. 6-year Ramp Rate for Conservation
G. Non-energy Impacts
H. Social Discount Rate

These sensitivities were performed to assess changes in the implementation rate, financial structure, and overall effectiveness of conservation measures.

Baseline: Conservation resources are implemented over 10 years using PSE's baseline assumptions on costs and energy savings.
Sensitivity F > Conservation measures are implemented over 6 years instead of 10 years, and associated costs and energy savings are updated.
Sensitivity G > Conservation measures include additional non-energy impacts. Assuming there are additional benefits not captured in the original dataset, this increases the amount of energy savings from conservation and demand response.
Sensitivity H > The discount rate of DSR projects is changed from 6.8 percent to 2.5 percent. When the discount rate is decreased, the present value of future DSR savings is increased.

KEY FINDINGS. Costs and resource builds remain relatively stable across changes to the conservation inputs. Sensitivity F (6-year Ramp) selected Bundle 9, Sensitivity G (Non-energy

Impacts) selected bundle 8 and Sensitivity G (Social Discount Rate) selected bundle 6, compared to bundle 10 in the Mid Scenario. Though lower conservation bundles were selected, additional demand response measures were added. Changes to the conservation assumptions push more energy savings measures into lower bundles so the portfolio selects similar or lower amounts of conservation for lower costs. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045, compared to making adjustments around ramp rates and discount rates.

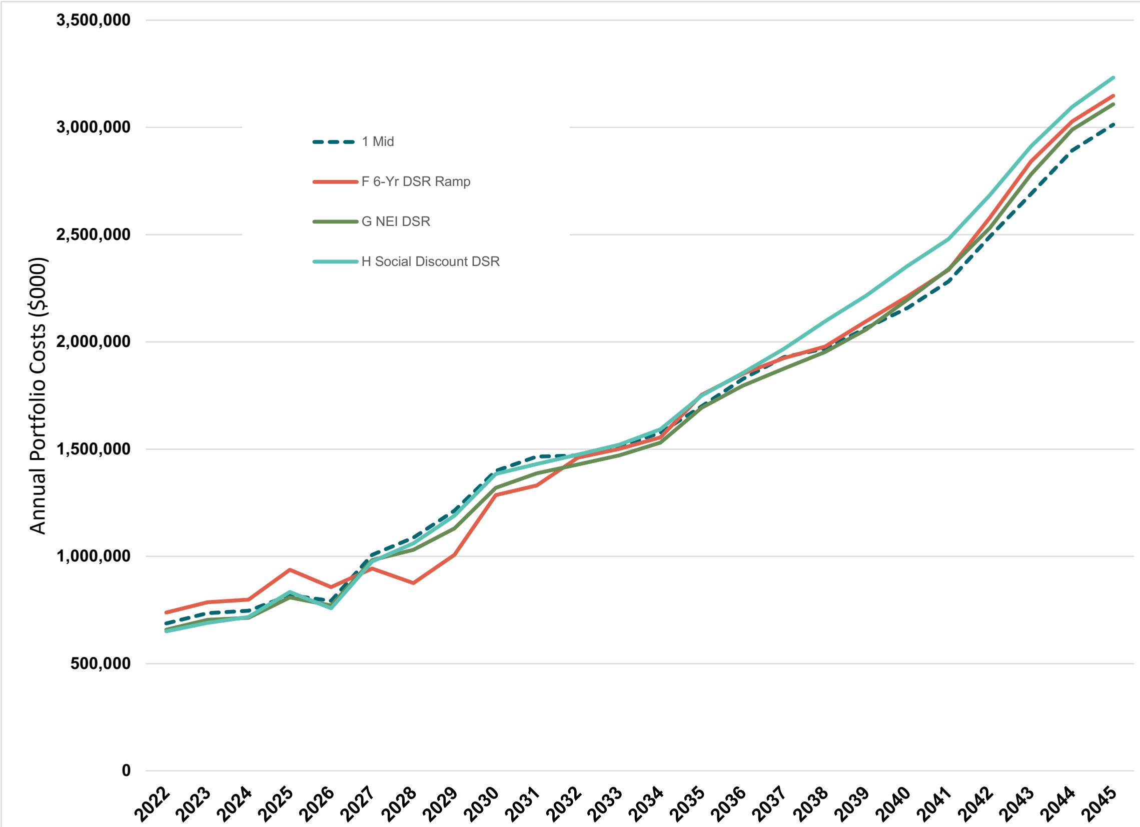
ASSUMPTIONS. These portfolios keep all underlying assumptions from the Mid Scenario portfolio, then change the costs and energy savings of the conservation measures available as resources. All DSR inputs in the Mid Scenario and Sensitivities F, G and H, can be found in Appendix H.

ANNUAL PORTFOLIO COSTS. Across all three sensitivities, changes to the overall costs of the portfolio are minor. In Sensitivity F, there is virtually no difference in overall portfolio cost compared to the Mid Scenario, although different timelines for the additions of Washington wind, Wyoming wind and Washington east solar lead to differences in annual costs in the earlier years of the simulation. Sensitivity G shows a small decrease in costs, achieving the same energy savings benefits as Sensitivity F at a lower cost conservation bundle. Sensitivity G also adds a frame peaker by 2045 compared to the Mid Scenario and Portfolio F, resulting in fewer battery builds. Frame peaker builds are a less expensive way to increase capacity and peak capacity, but the overall changes to the portfolio costs are small. Sensitivity H shows a minor increase in costs as a result of increased battery and renewable hybrid builds in the later years of the simulation. Otherwise, the portfolio costs of Sensitivity H follow the annual cost trends of the Mid Scenario.

Figure 8-49: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities F, G and H

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
F	6-Year Conservation Ramp Rate	$15.54	$5.09	$20.63	$0.01
G	Non-energy Impacts for DSR	$15.24	$5.12	$20.36	($0.26)
H	Social Discount Rate for DSR	$15.77	$5.16	$20.94	$0.32

Figure 8-50: Annual Portfolio Costs – Mid Scenario and Sensitivities F, G and H



RESOURCE ADDITIONS. Figures 8-51 and 8-52 compare the nameplate capacity additions of the Mid Scenario to Sensitivities F, G and H. Resource builds do not change significantly across the portfolios. Minor differences are seen in the timing of renewable resource construction and total nameplate capacity built. Any reductions in standalone renewable capacity are offset by increased hybrid resources or battery storage resources. Sensitivity H shows the largest increase in overall capacity, adding 100 MW of wind, 250 MW of hybrid resources and 100 MW of battery storage by 2045. Sensitivity F builds an additional 250 MW of hybrid resources and 75 MW of battery resources, but reduces standalone wind resources by 200 MW. Sensitivity G increases battery storage and standalone wind resources by 200 MW each, but reduces hybrid resource builds by 250 MW by 2045. These differences from the Mid Scenario are minor and affect the later years of the simulation.

Figure 8-51: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

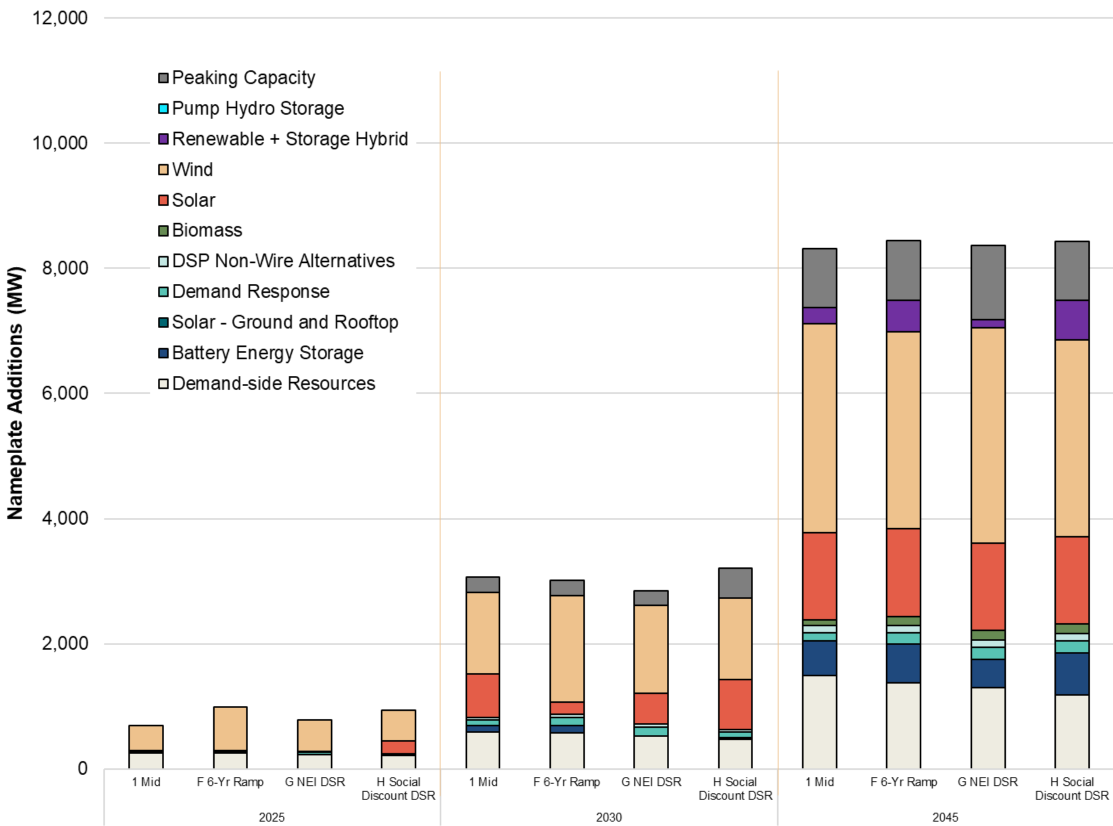


Figure 8-52: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

Resource Additions by 2045	1. Mid	F. 6-Yr DSR Ramp	G. NEI DSR	H. Social Discount DSR
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,179 MW
Battery Energy Storage	550 MW	625 MW	450 MW	675 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	175 MW	188 MW	195 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,694 MW	4,993 MW	4,691 MW
Biomass	90 MW	150 MW	150 MW	150 MW
Solar	1,393 MW	1,394 MW	1,393 MW	1,391 MW
Wind	3,350 MW	3,150 MW	3,450 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	500 MW	125 MW	625 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	1,185 MW	948 MW

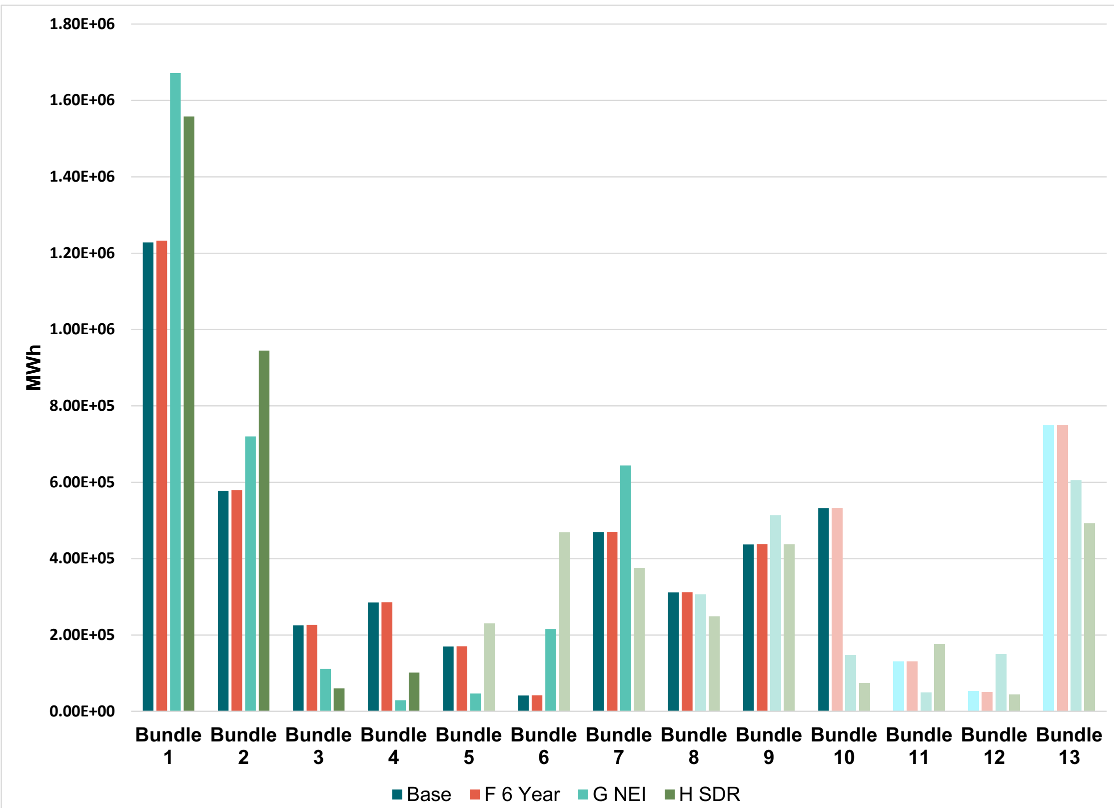
CHANGES IN CONSERVATION AND DEMAND RESPONSE. The primary focus of these sensitivities was to assess the implementation of changes to the available conservation measures. Figure 8-53 shows the final conservation selections in each sensitivity.

Figure 8-53: Conservation Measures Selected – Mid Scenario and Sensitivities F, G and H

Sensitivity	Conservation Bundle	Average Annual Energy Savings from Conservation	Number of Demand Response Measures	Capacity of Demand Response Measures Added
Mid Scenario	Bundle 10	718 aMW	3	123 MW
F - 6-Year Ramp	Bundle 9	659 aMW	5	175 MW
G - Non-Energy Impacts	Bundle 7	624 aMW	8	188 MW
H - Social Discount Rate	Bundle 4	538 aMW	9	195 MW

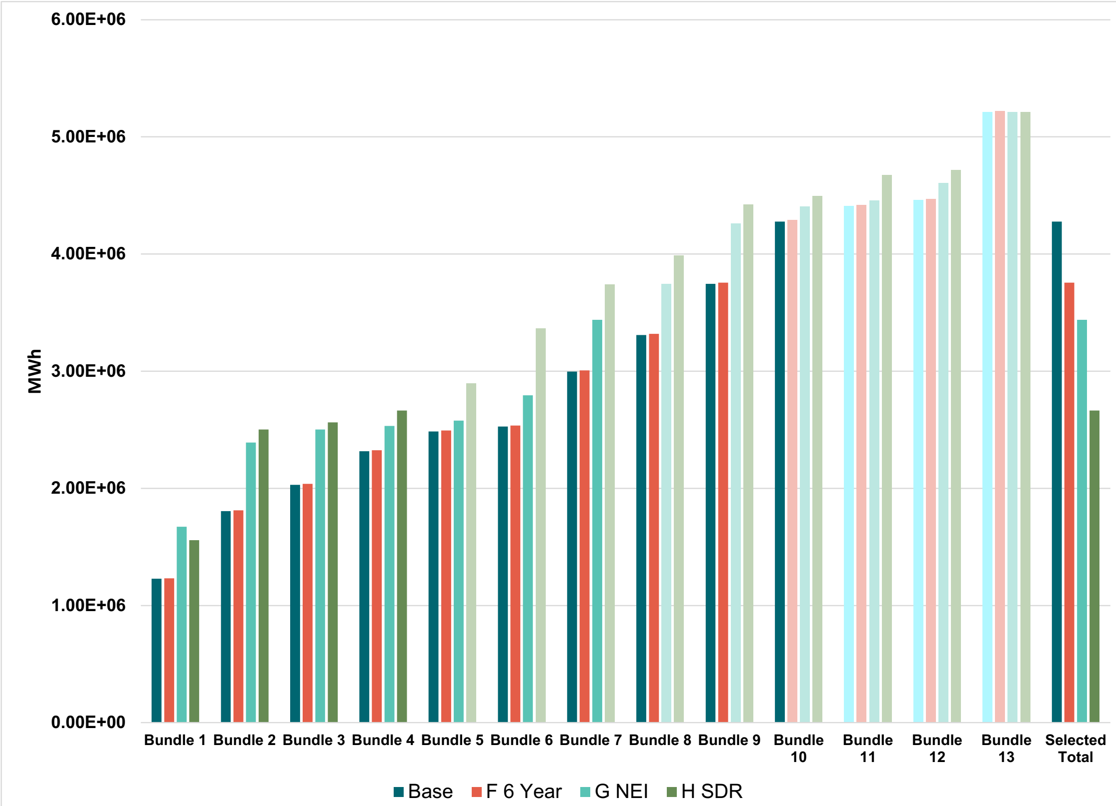
Updates to the DSR inputs changed the energy and cost values associated with each conservation measure. Since each conservation bundle is a collection of individual conservation programs within a price range, the assessment of individual measures within a bundle is not possible. However, the aggregate attributes of each bundle can be seen. Figure 8-39 shows the incremental energy savings provided by each bundle by 2045. In order to add a bundle in the AURORA model, the previous bundle must also be added (excluding Bundle 1), each bundle is dependent on adding the previous bundle. Figure 8-54 shows the cumulative energy savings provided by a selected bundle and all preceding bundles.

Figure 8-54: Incremental Energy Savings Provided by Each Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Across the DSR sensitivities, adjustments to the underlying DSR attributes push more energy savings into lower bundles. In the long-term capacity expansion model, AURORA responds to these changes by adding less conservation while increasing investment in demand response measures. This trend is shown in Figure 8-55 where the cumulative energy savings within each bundle is greater for Sensitivities F, G and H than the Mid Scenario (Base).

Figure 8-55: Cumulative savings Achieved by Each Incremental Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Social Cost of Greenhouse Gases and CO_2 Regulation

I. SCGHG as an Externality Cost in the Portfolio Model Only
J. SCGHG as an Externality Cost in the Portfolio Model and Dispatch Model

The goal of these sensitivities is to compare methodologies for applying the social cost of greenhouse gases to portfolios.

Baseline: The SCGHG is included as a planning adder to emitting resources in the long-term capacity expansion (LTCE) model. The planning adder is a fixed cost.

Sensitivity I > The SCGHG is included as an externality cost to emitting resources in the LTCE model. This externality cost is a variable cost of dispatch, in contrast to the fixed cost of the planning adder.

Sensitivity J > As in Sensitivity I, the SCGHG is included as an externality cost to emitting resources in the LTCE model. In addition, the SCGHG is included as a dispatch cost in the hourly dispatch model as a carbon tax.

KEY FINDINGS. Including the SCGHG in the LTCE and hourly dispatch models produces portfolios similar to the Mid Scenario. This is expected, as the CETA renewable requirement is the main driver of reduced emissions and thermal resources. In Portfolio I, costs and emissions are nearly identical to the Mid Scenario. In Portfolio J, which also includes the SCGHG as a carbon tax, the overall revenue requirement increases over the course of the planning horizon, but the largest increase occurs while Colstrip is operating from 2022 to 2025. Portfolio J also increases the use of market purchases to meet demand and shows a small decrease in overall emissions compared to the Mid Scenario.

ASSUMPTIONS. In both Sensitivity I and J, the SCGHG defined by CETA is simply applied as a variable cost on the dispatch of emitting resources. Figure 8-56 shows the value of the SCGHG as defined by CETA and the conversion used in AURORA.

In Sensitivity J, the SCGHG is also applied as a carbon tax in the hourly dispatch model. This requires an updated power price dataset since a carbon tax would impact the operations of all utilities in Washington.

Figure 8-56: CETA Definition of SCGHG and the Converted Values Used in AURORA

Year	2019$ / metric ton CO2	AURORA Input 2012$ / short ton CO2
2022	77.73	59.33
2023	78.95	60.25
2024	80.16	61.18
2025	82.59	63.03
2026	83.81	63.96
2027	85.02	64.89
2028	86.24	65.81
2029	87.45	66.74
2030	88.67	67.67
2031	89.88	68.60
2032	91.09	69.52
2033	92.31	70.45
2034	93.52	71.38
2035	94.74	72.30
2036	95.95	73.23
2037	98.38	75.08
2038	99.60	76.01
2039	100.81	76.94
2040	102.03	77.86
2041	103.24	78.79
2042	104.46	79.72
2043	105.67	80.65
2044	106.88	81.57
2045	108.10	82.50

ANNUAL PORTFOLIO COSTS. Figures 8-57 and 8-58 illustrate the breakdown of costs between the Mid Scenario and Sensitivities I and J.

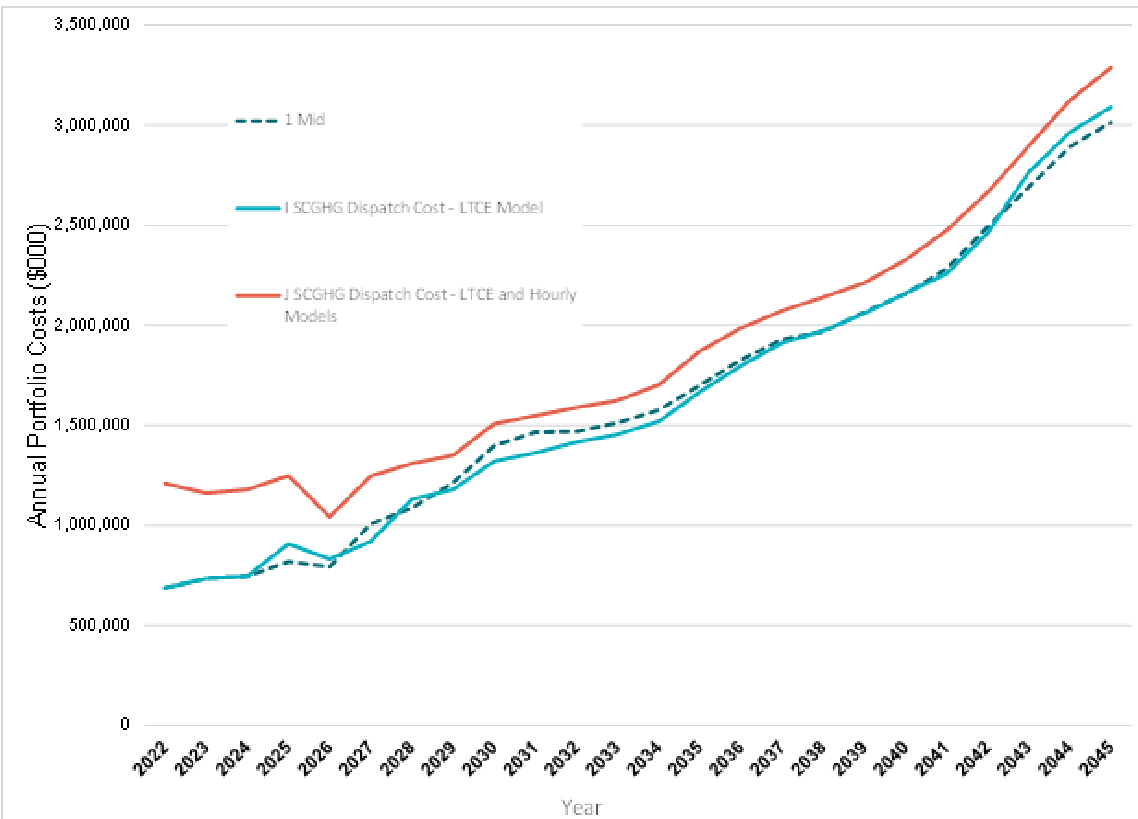
The final builds of the portfolios are similar, though Portfolio J greatly increases the emission costs of the portfolio in earlier years since the emissions of Colstrip and other thermal resources are now also taxed in the hourly dispatch model. After the retirement of Colstrip, as the carbon tax delays the construction of more flexible capacity resources, Portfolio J emissions do decrease compared to the portfolios in the Mid Scenario and Sensitivity I. Despite these differences, the cost trends of the portfolios remain the same after 2036. Sensitivity J has a higher overall cost since the SCGHG is now included as a dispatch cost and in the electric price forecast. This makes it difficult to divide out the revenue requirement from SCGHG. Even though sensitivity J has a lower SCGHG cost, it only reflects the cost of generating resources; the cost of market is in the revenue requirement, so it is hard to compare this portfolio against the Mid scenarios.

Figure 8-57: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivities I and J

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
I	SCGHG Externality Cost – LTCE Model Only	$15.41	$5.10	$20.51	($0.11)
J	SCGHG Externality Cost – LTCE Model and Hourly Dispatch*	$18.45	$4.81	$23.26	$2.64

* *Sensitivity J uses a different electric price forecast than the Mid Scenario.*

Figure 8-58: Annual Portfolio Costs – Mid Scenario, Sensitivity I and Sensitivity J



RESOURCE ADDITIONS. Figures 8-59 and 8-60 compare the nameplate capacity additions of the Mid Scenario to Sensitivities I and J. Both sensitivities select Bundle 10 for conservation and reach 2045 with a similar builds of batteries and renewables. Timing of resources builds is different for each sensitivity, but both result in similar portfolios to the Mid Scenario.

Sensitivity I builds one less frame peaker than the Mid Scenario, but adds 55 MW of reciprocating peakers. It also builds 200 MW less of Washington wind and 100 MW less of Washington solar than the Mid Scenario, but adds 125 MW of hybrid resources to the portfolio. Overall, Sensitivity I adds 325 MW more battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 575 MW of 4-hour lithium-ion batteries built compared to the Mid Scenario's 50 MW.

Sensitivity J builds two fewer frame peakers than the Mid Scenario, but adds 273 MW of reciprocating peakers. Washington wind capacity increases by 200 MW by 2045, and Washington solar capacity decreases by 400 MW, netting the same overall intermittent renewable nameplate capacity as Portfolio I. Portfolio J also adds 125 MW of hybrid resources. Overall, Sensitivity J adds an additional 300 MW more of battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 400 MW of 6-hour flow batteries built compared to no 6-hour flow batteries the Mid Scenario.

Figure 8-59: Portfolio Additions – Mid Scenario and Sensitivities I and J

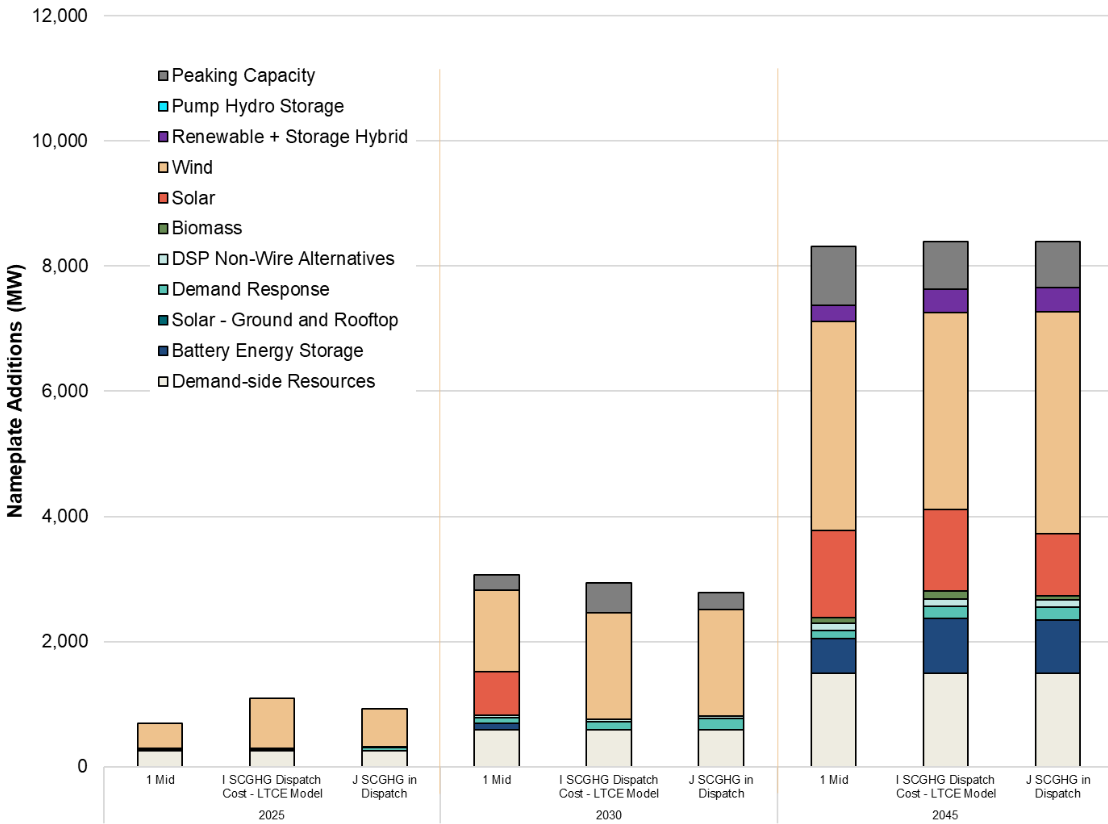


Figure 8-69: Portfolio Additions – Mid Scenario and Sensitivities I and J

Resource Additions by 2045	1 Mid	I SCGHG Dispatch Cost - LTCE Model	J SCGHG Dispatch Cost - LTCE and Hourly Models
Demand-side Resources	1,497 MW	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	875 MW	850 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	188 MW	205 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,579 MW	4,606 MW
Biomass	90 MW	135 MW	60 MW
Solar	1,393 MW	1,294 MW	996 MW
Wind	3,350 MW	3,150 MW	3,550 MW
Renewable + Storage Hybrid	250 MW	375 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	766 MW	747 MW

EMISSIONS. Emissions are the largest difference between Sensitivity I and J. Figure 8-61 compares the direct emissions of the Mid Scenario, Sensitivity I and Sensitivity J. Portfolio J builds a similar amount of peaking capacity as Portfolio I, but relies much more heavily on market purchases to meet demand. Including the market purchase emission rate assumed in CETA brings Portfolio J in line with Sensitivity I, showing a modest decrease in emissions as shown in Figure 8-62. This is expected, as the CETA renewable requirement is the main driver of emissions reductions, not the SCGHG.

Figure 8-61: Direct Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases not included)

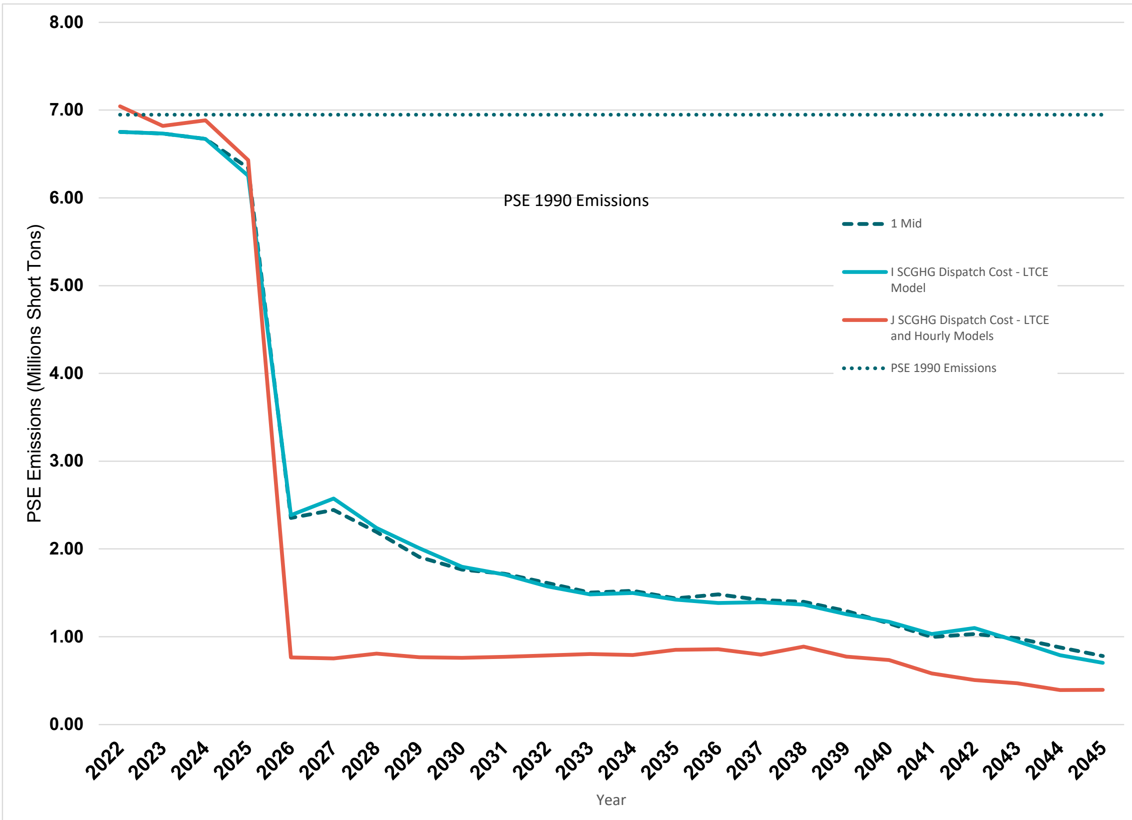
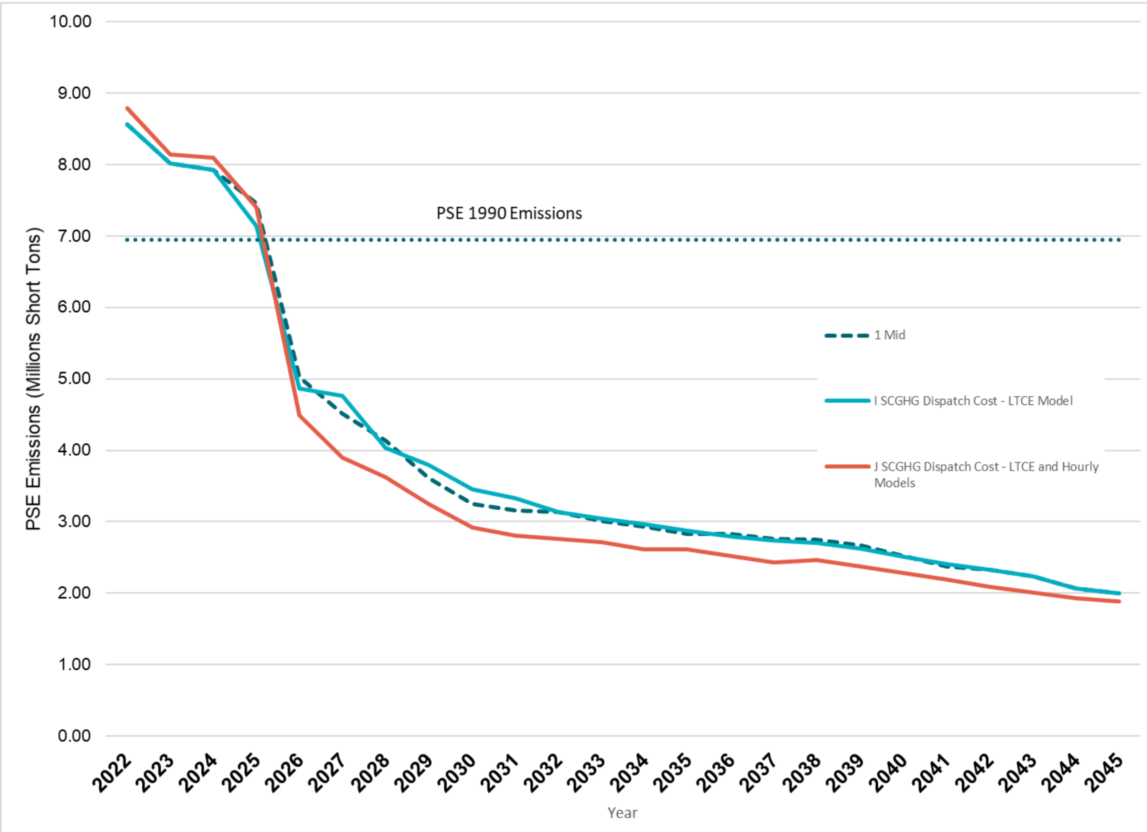


Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



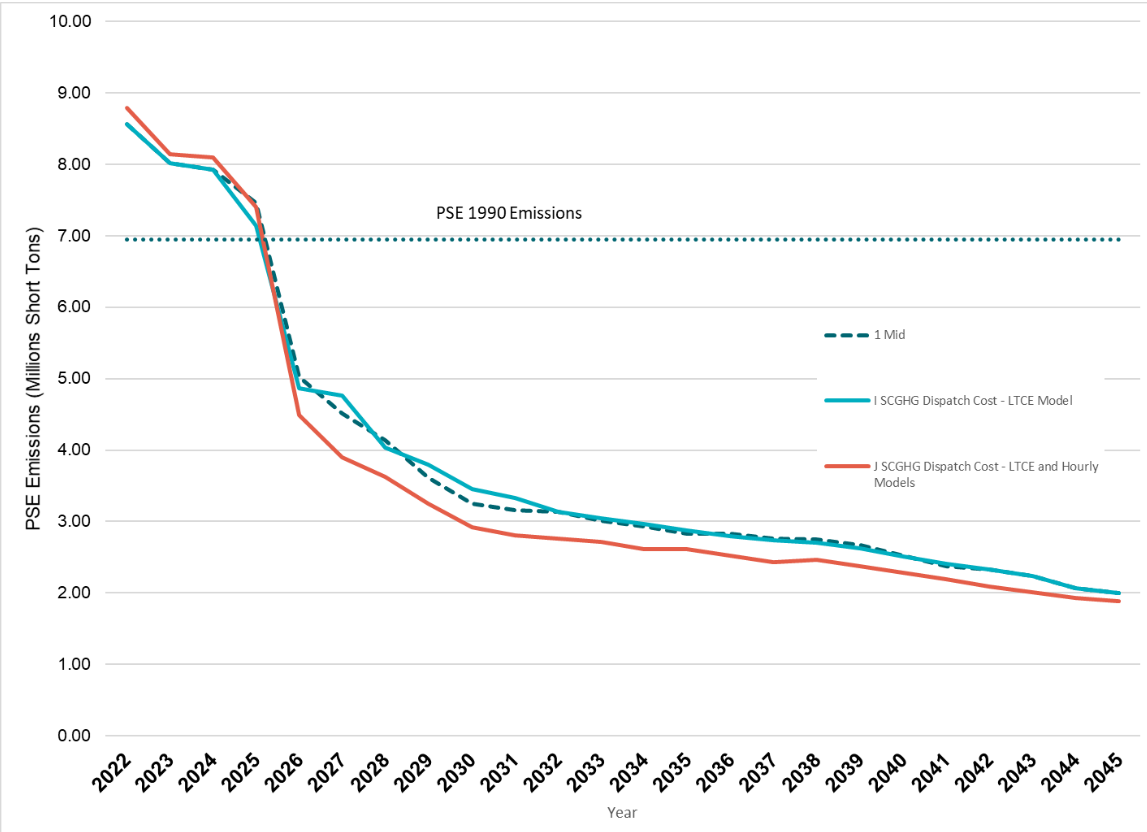
K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

ASSUMPTIONS. The sensitivity is updated to include the AR5 methodology of calculating upstream emissions. Figure 8-63 compares the emission rates of resources in the Mid Scenario and Sensitivity K. All other underlying assumptions from the Mid Scenario portfolio are kept the same.

Figure 8-63: Upstream Emission Rates – Mid Scenario (AR4) and Sensitivity K (AR5)

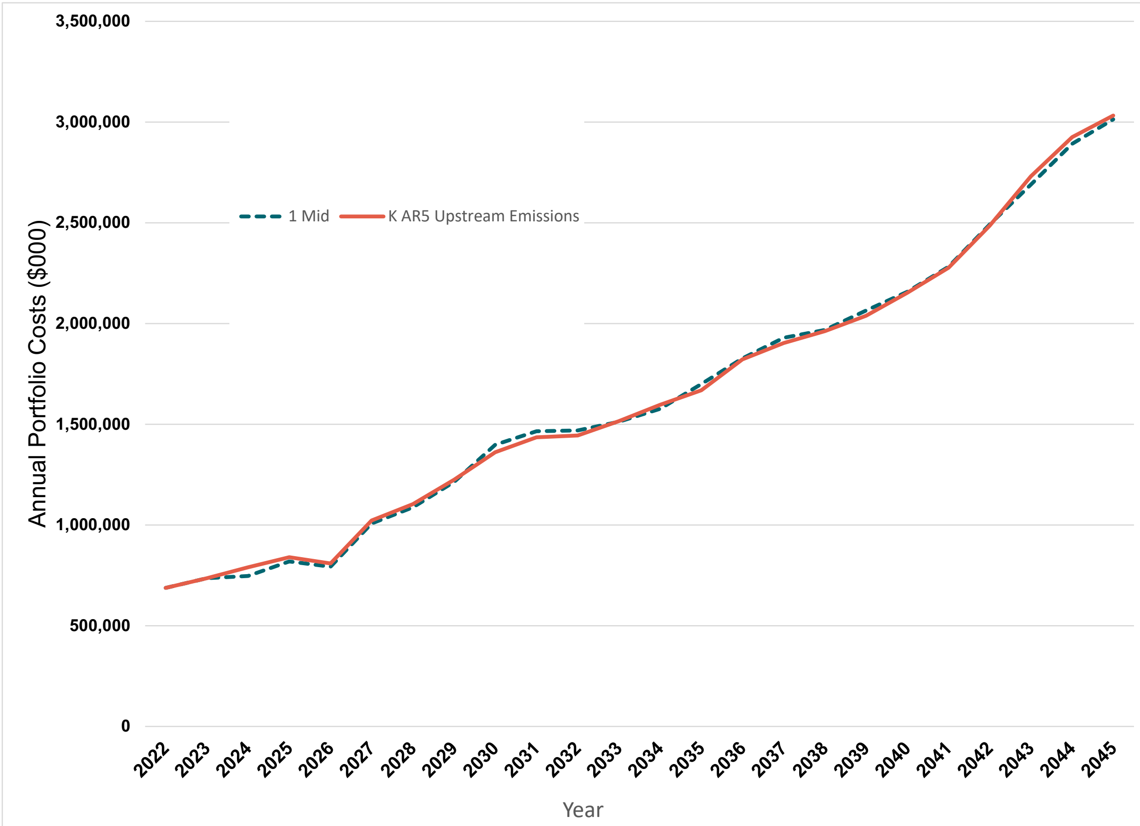
Resource	Mid Scenario AR4 Upstream Emission Rates (lb/mmBtu)	Sensitivity K AR5 Upstream Emission Rates (lb/mmBtu)
New Frame Peaker	23	24
New Recip Peaker	23	24

ANNUAL PORTFOLIO COSTS. The costs of the Sensitivity K and Mid Scenario portfolios are nearly identical. There are no significant changes in portfolio builds that would lead to changes in costs. The increased emissions costs are expected, as thermal plants are associated with slightly higher emissions.

Figure 8-64: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity K

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
K	**AR5 Emissions**	$15.56	$5.14	$20.71	$0.09

Figure 8-65: Annual Portfolio Costs – Mid Scenario and Sensitivity K



RESOURCE ADDITIONS. Figures 8-66 and 8-67 compare the nameplate capacity additions in the portfolios of the Mid Scenario and Sensitivity K. Both select Bundle 10 for conservation, and Sensitivity K selects four additional demand response resources for a total of seven. Minor differences are seen in the timing of wind and solar resources. Nearly the same amount of peaking capacity, solar and hybrid capacity is built by 2045 in both portfolios. However, 200 MW less of wind and an additional 75 MW of battery storage are built by 2045 in the Sensitivity K portfolio.

Figure 8-66: Portfolio Additions – Mid Scenario and Sensitivity K

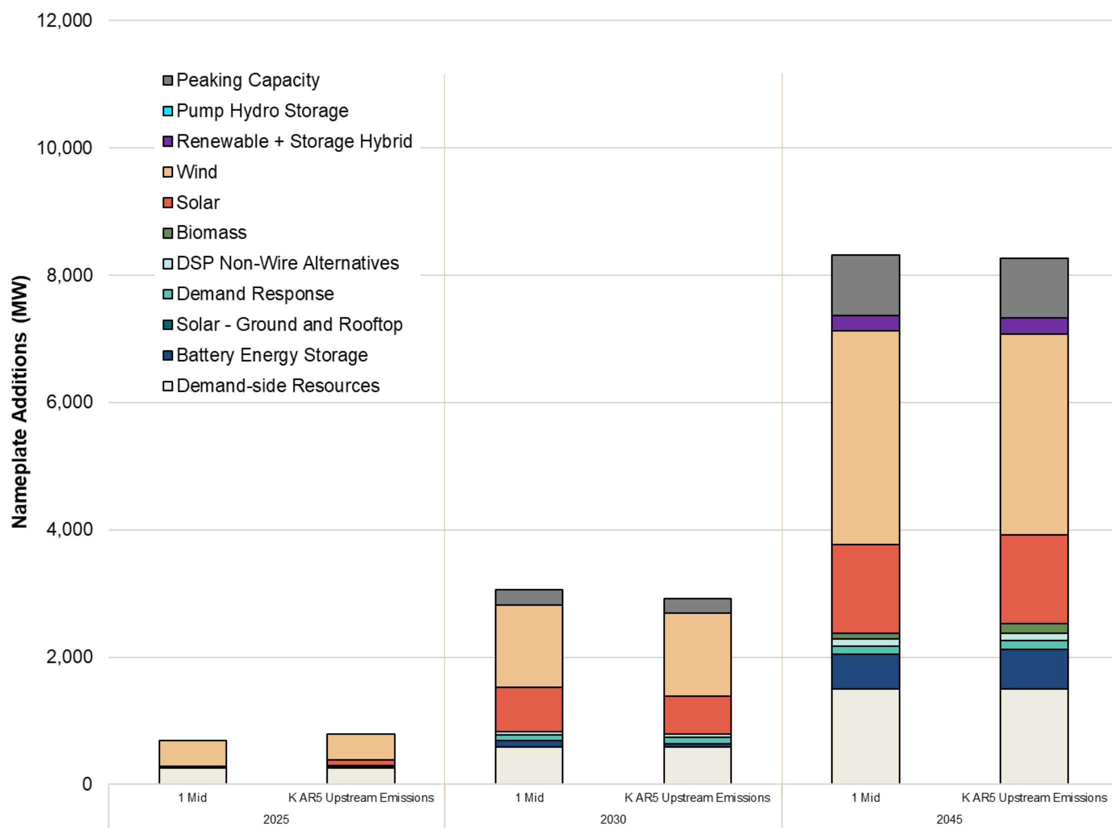
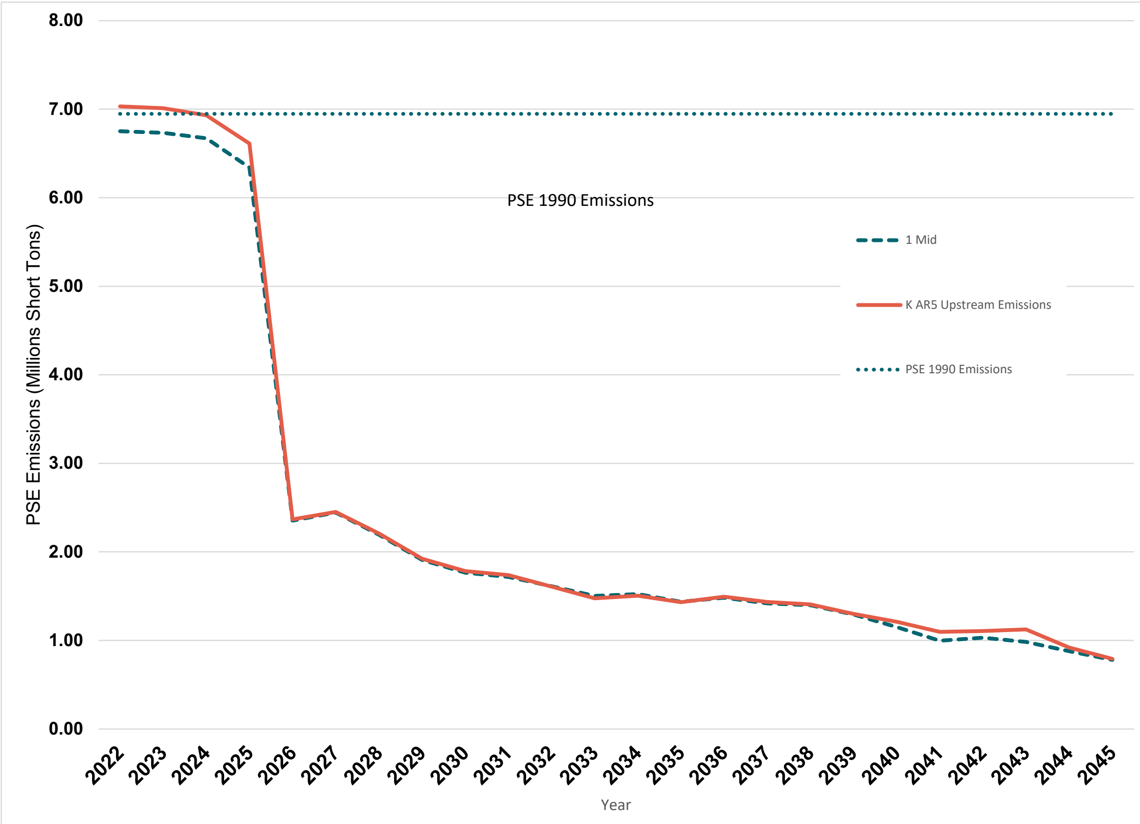


Figure 8-67: Portfolio Additions – Mid Scenario and Sensitivity K

Resource Additions by 2045	1 Mid	K AR5 Upstream Emissions
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	625 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	140 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,693 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,393 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

EMISSIONS. Changing to the AR5 methodology does not significantly change the emissions of Portfolio K. Figure 8-68 compares the emissions of the Mid Scenario and Portfolio K. The change to the AR5 methodology makes the most difference in the earlier years when dispatch of the natural gas resources are higher. Over time, the dispatch of the natural gas resources drops significantly enough that there is negligible change in emissions between the two portfolios.

Figure 8-68: Annual Emissions – Mid Scenario and Portfolio K



L. SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

This sensitivity examines the impact of adding a Federal CO_2 tax in addition to SCGHG as a fixed cost adder for thermal plants during the resource selection process.

Baseline: The SCGHG is included as a planning adder (fixed cost) to thermal resources during the LTCE modeling process.

Sensitivity L > In addition to SCGHG as a planning adder (fixed cost) to thermal resources during the LTCE modeling process, a Federal CO_2 tax is applied to emissions from thermal resources during both the LTCE modeling process and the hourly dispatch model. This Federal CO_2 tax is applied to the power prices of the portfolio as well, which affects all WECC resources.

KEY FINDINGS. There is relatively little change to the renewable resource additions in Sensitivity L since the CETA requirement drives renewable portfolio additions rather than the SCGHG or a Federal CO_2 tax. However, adding a Federal CO_2 alters the dispatch of thermal resources. The capacity factor of all thermal plants declines overtime as the Federal CO_2 tax increases during the planning horizon.

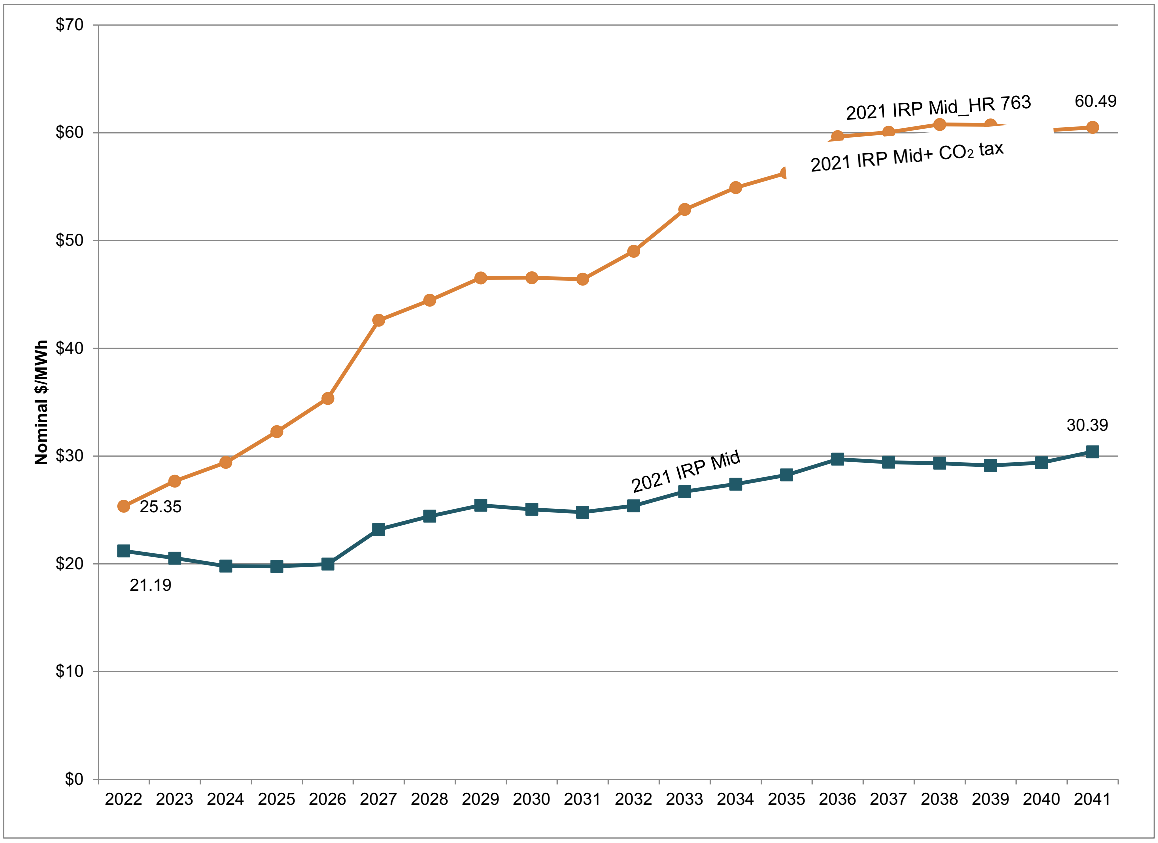
ASSUMPTIONS. For this sensitivity, PSE modeled the Energy Innovation and Carbon Dividend Act of 2019 (H.R. 763) that was introduced in Congress on January 2019, as the assumed federal CO_2 tax. The bill imposes a fee on the carbon content of fuels, including crude oil, natural gas, coal or any other product derived from those fuels. The fee is imposed on the producers or importers of the fuels and is equal to the greenhouse gas content of the fuel multiplied by the carbon fee rate. The rate begins at $15 in 2019, increases by $10 each year, and is subject to further adjustments based on progress in meeting specified emissions reduction targets. Figure 8-69 shows the value of the Federal CO_2 tax included in AURORA and the SCGHG used for this sensitivity.

Figure 8-69: SCGHG under CETA and the Federal CO_2 Tax under H.R. 763
(in 2012 dollars per short ton)

Year	SCGHG 2012$ / short ton CO_2	Federal CO_2 Tax 2012$ / short ton CO_2
2022	59.33	12.33
2023	60.25	20.35
2024	61.18	28.37
2025	63.03	36.20
2026	63.96	43.83
2027	64.89	51.28
2028	65.81	58.55
2029	66.74	65.64
2030	67.67	72.56
2031	68.60	79.31
2032	69.52	85.90
2033	70.45	92.32
2034	71.38	98.59
2035	72.30	104.70
2036	73.23	110.67
2037	75.08	116.49
2038	76.01	122.17
2039	76.94	127.71
2040	77.86	133.11
2041	78.79	138.38
2042	79.72	143.53
2043	80.65	148.55
2044	81.57	153.44
2045	82.50	158.22

Using the Federal CO_2 tax requires an updated power price forecast since the Federal tax would impact the operations of all thermal plants in the WECC. Figure 8-70 compares the addition of a Federal CO_2 tax to Mid-C power prices with the Mid Scenario power price forecast. The 20-year levelized Mid-C power price is $43.11 per MWh, an increase of almost $19 per MWh over the Mid Scenario power prices.

Figure 8-70: Mid-C Power Prices – Mid Scenario and Sensitivity L (in 2012 dollars per short ton)

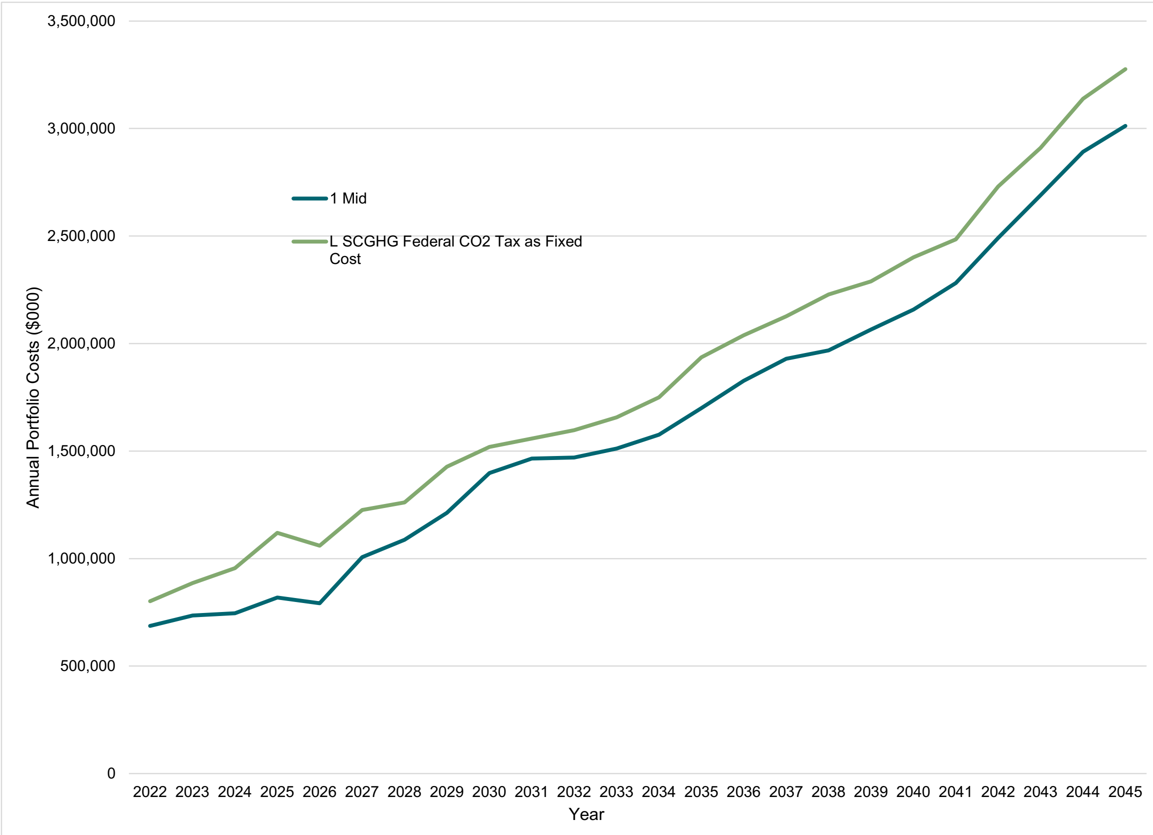


ANNUAL PORTFOLIO COSTS. The Sensitivity L portfolio costs are $2.24 billion higher than Mid Scenario costs. The higher costs can be attributed to the increase in market purchases and the selection of conservation Bundle 11 in Sensitivity L instead of conservation Bundle 10 in the Mid Scenario portfolio. Emissions costs in Sensitivity L are lower since thermal plants are dispatching less and generating lower emissions.

Figure 8-71: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity L

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	$17.77	$4.71	$22.47	$2.24

Figure 8-72: Annual Portfolio Costs – Mid Scenario and Sensitivity L



RESOURCE ADDITIONS. Figure 8-73 compares the nameplate capacity additions in the Mid Scenario and Sensitivity L portfolios. Adding the Federal CO_2 tax not only reduced the amount of flexible capacity resources added, but it also changed the mix of those flexible capacity resources. Sensitivity L adds a combined-cycle turbine in 2026, while the Mid Scenario adds a frame peaker in 2026. Sensitivity L also selects a higher conservation bundle (Bundle 11 compared to Bundle 10 in the Mid Scenario) and two additional demand response resources for a total of five. Minor differences are seen in the portfolio builds for solar, wind and hybrid capacity built by 2045.

Figure 8-73: Portfolio Additions – Sensitivity L and Mid Scenario

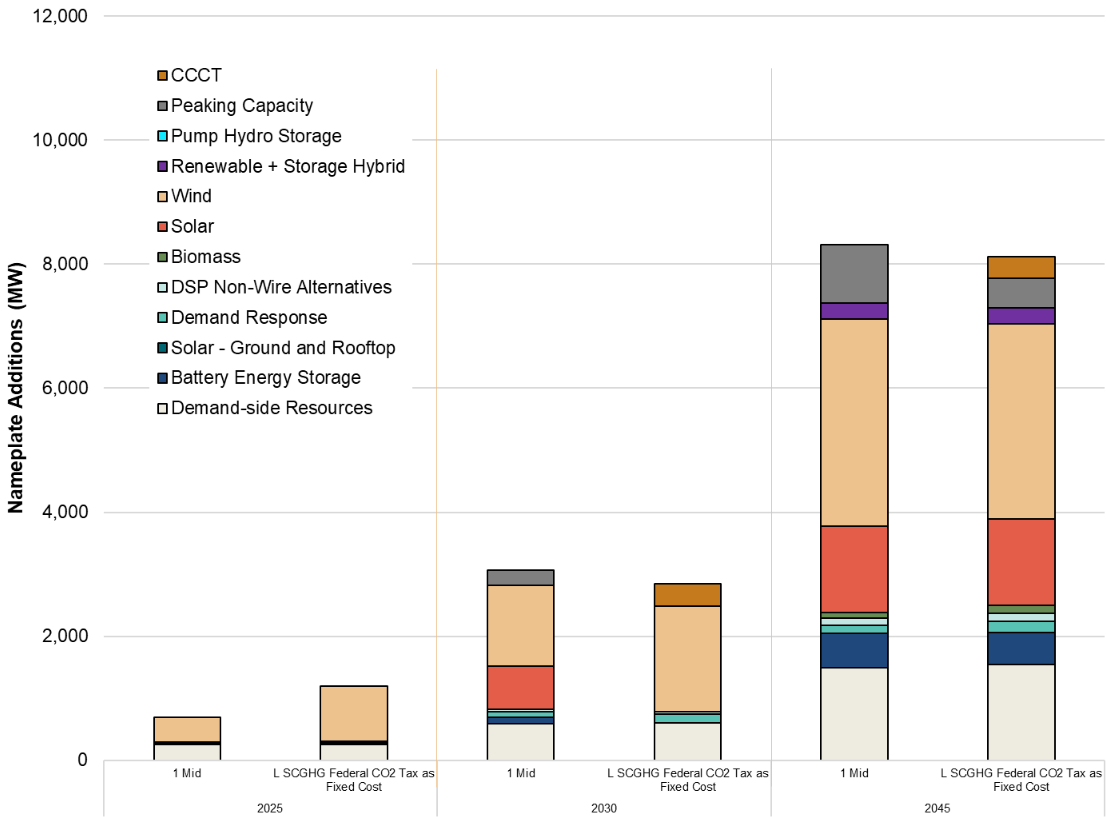


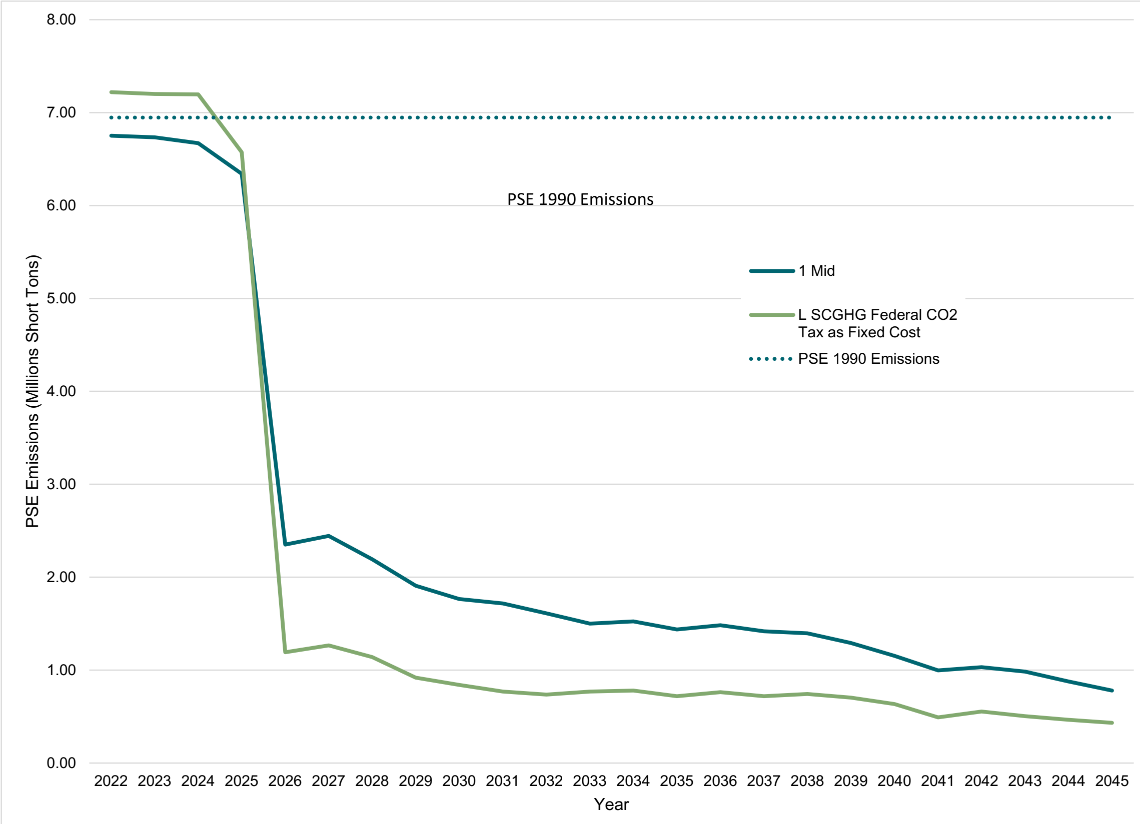
Figure 8-74 compares the nameplate capacity additions of the Mid Scenario and Sensitivity L portfolios by 2045.

Figure 8-74: Portfolio Additions – Mid Scenario and Sensitivity L

Resource Additions by 2045	1 Mid	L Federal CO_2 Tax SCGHG as Fixed Cost
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	183 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,680 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,395 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW
CCCT	0 MW	355 MW

EMISSIONS. Inclusion of a Federal CO_2 tax changed the emissions of Portfolio L significantly. In Portfolio L, after a large decline in emissions following the retirement of Centralia and Colstrip in 2026, existing and new thermal plants dispatch less and generate lower emissions due to the cost hurdle imposed by the Federal CO_2 tax. As a result, market purchases increased in Sensitivity L to make up for the decline in energy from thermal plants. Figure 8-75 compares the emissions of the Mid Scenario and Sensitivity L portfolios.

Figure 8-75: Annual Emissions – Mid Scenario and Portfolio L



Emissions Reduction

M. Alternative Fuel for Peakers

This sensitivity examines the effects of replacing the fuel supply for new frame peaker resources with a renewable fuel source, specifically biodiesel.

Baseline: New frame peaker resources are supplied with natural gas as their primary fuel source.
Sensitivity > New frame peaker resources are supplied with biodiesel as their primary fuel source.

KEY FINDINGS. In Sensitivity M, substituting biodiesel for natural gas in new frame peakers has only subtle impacts on the resulting portfolio. The 24-year levelized portfolio costs remain relatively unchanged, and resource additions are very similar to the Mid Scenario. GHG emissions are reduced slightly over the course of the modeling horizon. Biodiesel may be a feasible, cost-effective option for fueling peaking capacity resources while attaining CETA's zero emission goals and maintaining grid reliability.

ASSUMPTIONS. In Sensitivity M, new frame peaker resources are supplied with biodiesel as their primary fuel source. It is assumed that there are negligible differences between natural gas and biodiesel-fueled frame peakers in plant capital costs and fixed and variable operations and maintenance costs. Biodiesel is only available to frame peakers; new reciprocating peakers, new combined-cycle plants. Existing thermal resources are fueled with natural gas.

The market price for biodiesel was estimated from PSE experience and informed by the U.S. Department of Energy Clean Cities Alternative Fuel Price Report, October 2020. PSE has assumed a fixed biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020 dollars, adjusted for inflation annually) over the entire study period.

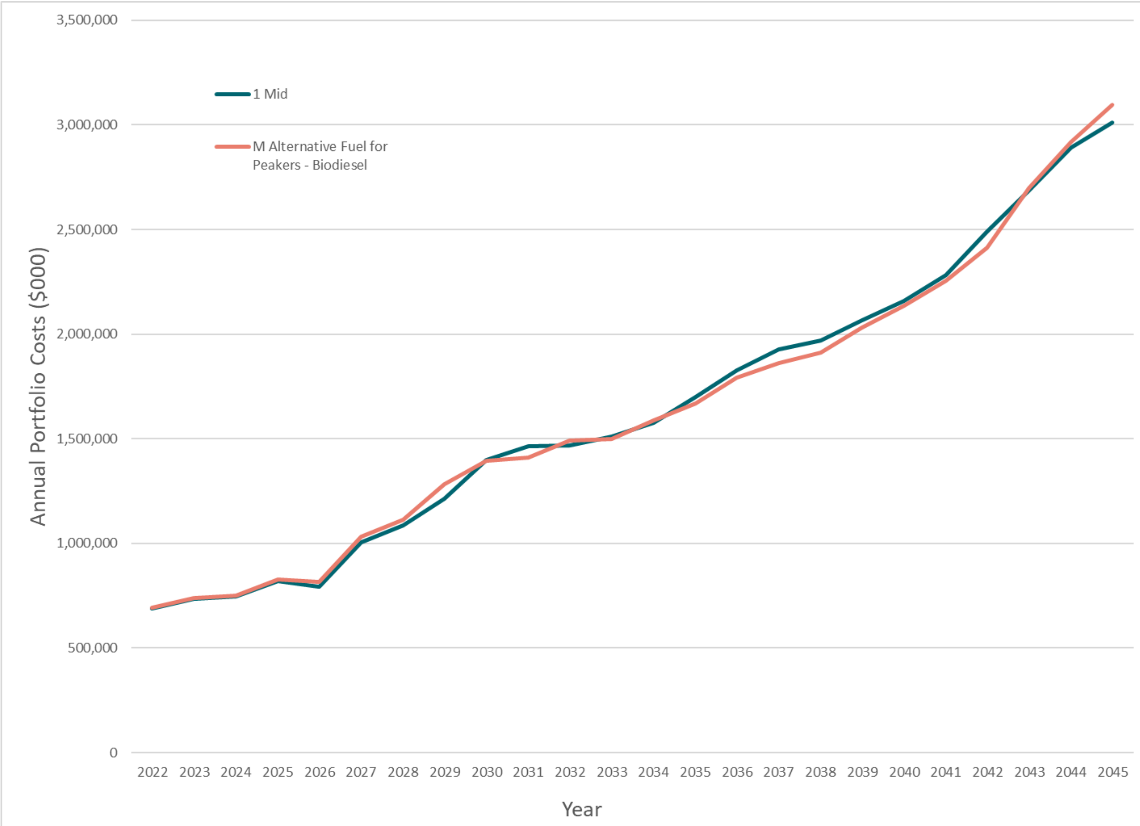
Given the anticipated constraints on biodiesel fuel supply, the flexibility benefit of frame peakers was removed ($0/kW-yr) in Sensitivity M as compared to the flexibility benefit of $23.45/kW-yr for frame peakers in the Mid Scenario.

PORTFOLIO COSTS. Figures 8-76 and 8-77 compare the breakdown of costs between the Mid Scenario and Sensitivity M portfolios. The 24-year levelized cost of Sensitivity M is nearly equal to the cost of Mid Scenario. However, the social cost of greenhouse gases is $100 million less in Sensitivity M compared to the Mid Scenario due to the use of a carbon neutral fuel for new frame peakers.

Figure 8-76: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity M

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
M	Alternative Fuel for Peakers	$15.53	$4.99	$20.52	($0.10)

Figure 8-77: Annual Portfolio Costs – Mid Scenario and Sensitivity M



RESOURCE ADDITIONS. Figures 8-78 and 8-79 compare the nameplate capacity additions of the Sensitivity M and Mid Scenario portfolios. Resource additions for Sensitivity M are very similar to those in the Mid Scenario. Both add the same quantity of peaking capacity, hybrid resources and similar quantities of renewable resources. Sensitivity M builds slightly more solar and slightly less wind than the Mid Scenario, and Sensitivity M selects conservation Bundle 11, whereas the Mid Scenario selects Bundle 10.

Figure 8-78: Portfolio Additions – Sensitivity M and the Mid Scenario

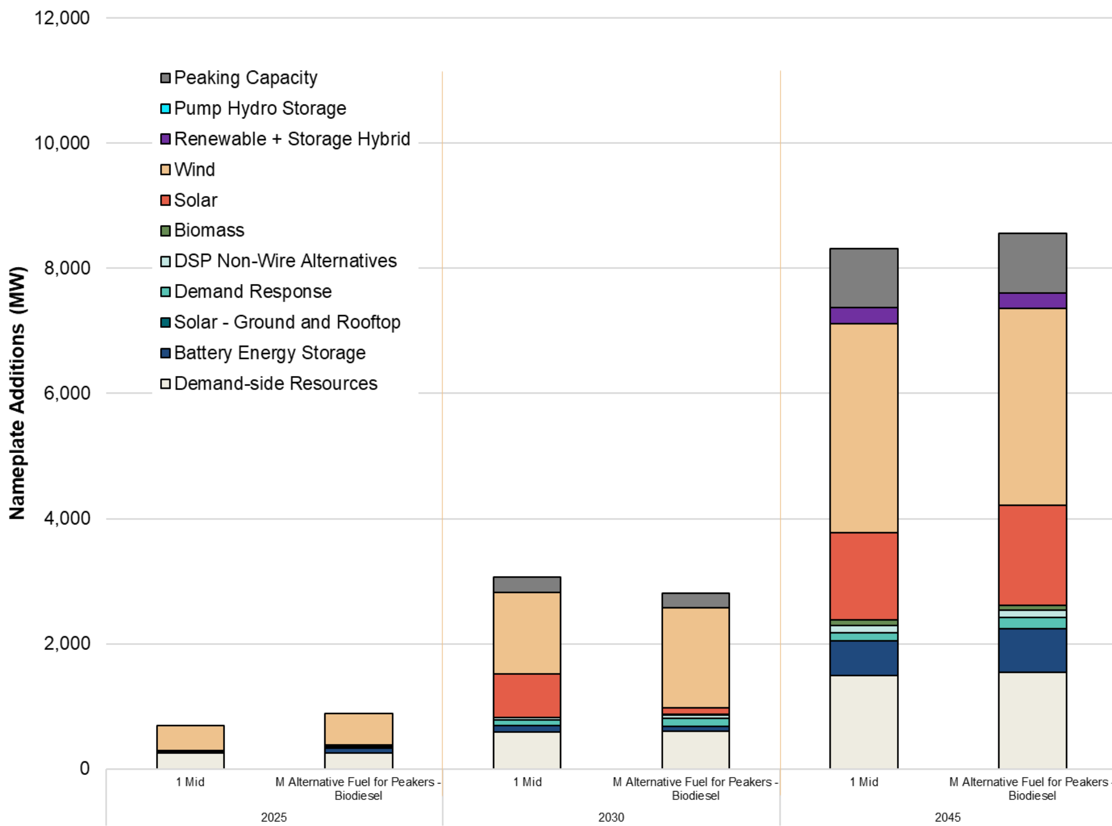
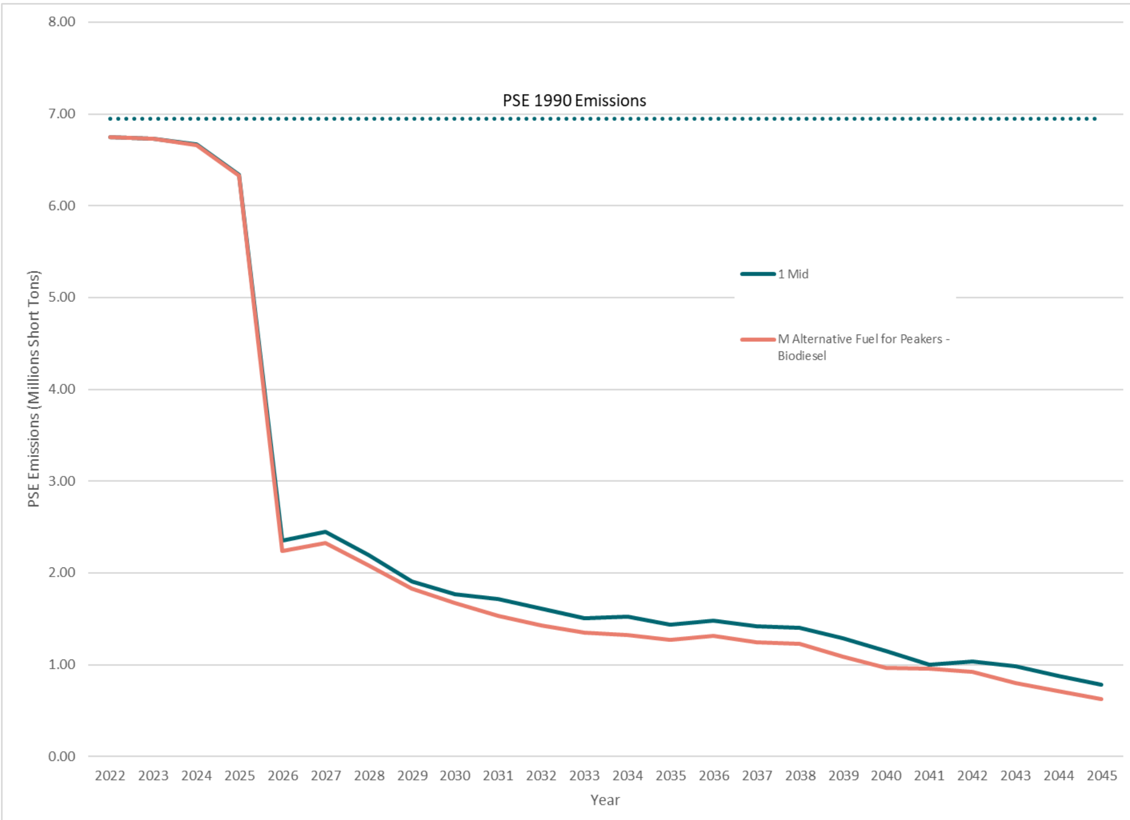


Figure 8-79: Portfolio Additions by 2045 – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers

Resource Additions by 2045	1. Mid	M. Alternative Fuel for Peakers
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	700 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	185 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,818 MW
Biomass	90 MW	75 MW
Solar	1,393 MW	1,593 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

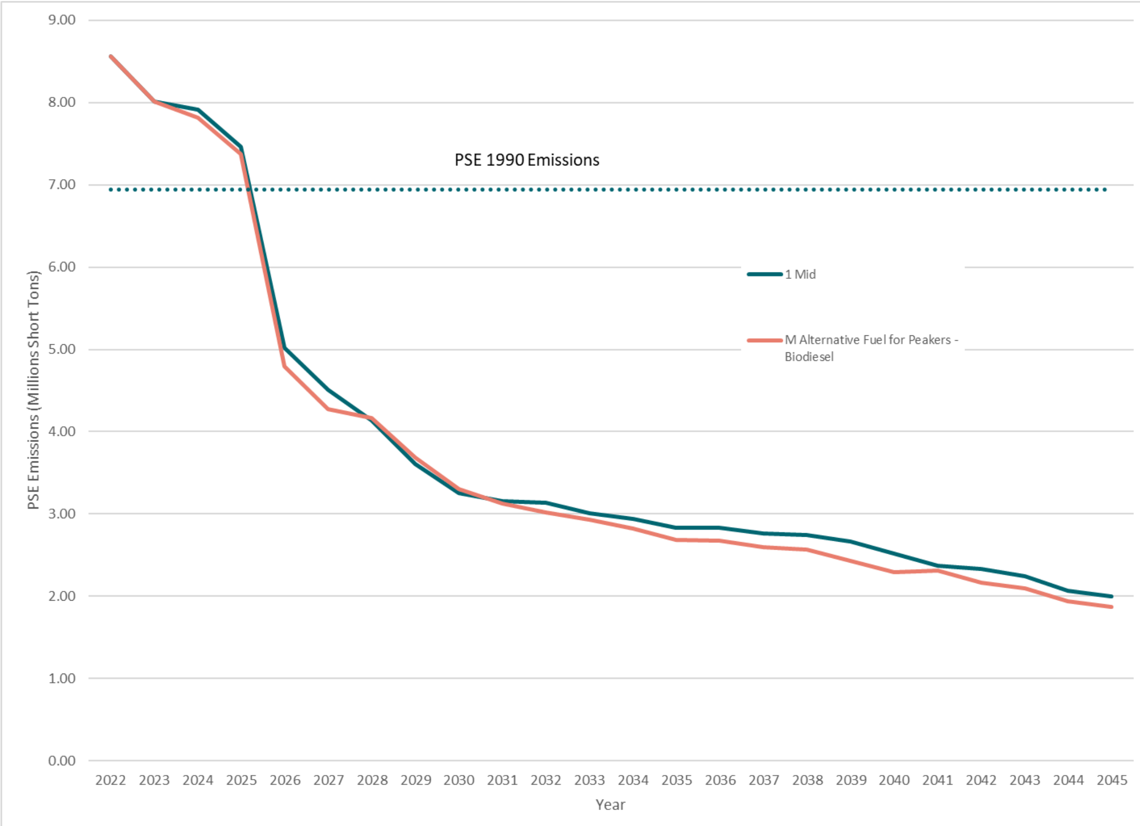
EMISSIONS. Sensitivity M resulted in fewer direct GHG emissions compared to the Mid Scenario due to the use of a carbon neutral fuel for peaking capacity needs. Figure 8-80 compares the GHG emissions from the Mid Scenario and Sensitivity M portfolios. Following acquisition of the first peaking capacity resource in 2026, Sensitivity M has consistently lower GHG emissions over the course of the modeling horizon.

Figure 8-80: Direct GHG Emissions – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers



A similar trend is observed in Figure 8-81 which compares GHG emissions from the Sensitivity M with the Mid Scenario emissions, including both direct and indirect (i.e. market) emissions. Sensitivity M maintains lower emissions, however, the difference in emission reductions between the two portfolios is smaller.

Figure 8-81: Direct and Indirect GHG Emissions– Mid Scenario and Sensitivity M



To put emission reductions into perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-82 shows the results of this calculation for Sensitivity M and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. Sensitivity M is very efficient a reducing portfolio emissions; this is why biodiesel was added a fuel to the preferred portfolio.

Figure 8-82: Cost of Emissions Reduction – Mid Scenario, Sensitivity M and Sensitivity W (the Preferred Portfolio)

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
M Alternative Fuel for Peakers	52.84	$15.53	<0.01
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

CAPACITY FACTOR. Despite the much higher cost of biodiesel ($30.53/MMBtu) as compared to natural gas ($3.56/MMBtu), the overall revenue requirement of Sensitivity M and the Mid Scenario are roughly equal. This is because the high cost of biodiesel drives down the dispatch frequency of the new frame peaking resources. New frame peakers in the Mid Scenario had an annual capacity factor of about 3 percent in the year 2045. In Sensitivity M, the annual capacity factor of new frame peakers dropped to less than 0.1 percent. This suggests that the frame peakers were only dispatched in periods of peak demand to fill a specific role in providing peak capacity to the portfolio.

BIODIESEL AVAILABILITY. When modeling a portfolio like Sensitivity M that relies on a limited commodity such as biodiesel, it is important to consider the availability of that resource. Washington state produced around 114 million gallons of biodiesel in 2019 from two facilities.[5] In Sensitivity M, biodiesel fueled frame peakers supplied, at most, 7,233 MWh of energy over the modeling horizon. This equates to an annual need of approximately 600,000 gallons of biodiesel or about 0.5 percent of Washington State's annual production. This relationship suggests that the Washington biodiesel market could plausibly support the use of biodiesel for peak need electricity generation. PSE also evaluated the fuel needed to maintain resource adequacy which is included in Chapter 7.

5 / https://www.eia.gov/biofuels/biodiesel/production/

N. 100% Renewable by 2030

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that advances the CETA target of 100 percent renewable energy to 2030.

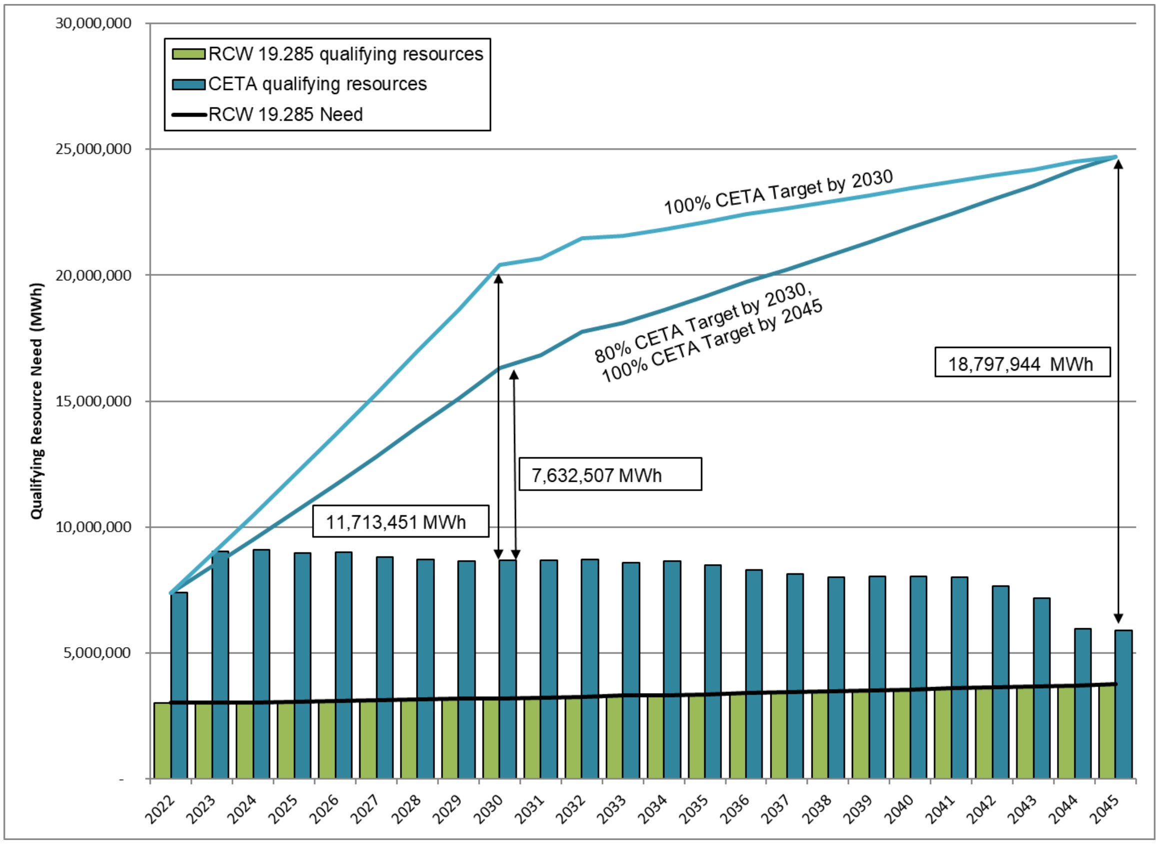
Baseline: 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.
Sensitivity > 100 percent of sales must be met by non-emitting/renewable resources by 2030.

KEY FINDINGS. Sensitivity N demonstrates that achieving a 100 percent renewable portfolio is possible with existing technologies, but the cost to do so is unrealistically high. The 24-year levelized portfolio cost of Sensitivity N is $15.17 and $33.37 billion more than the Mid Scenario for variations N1 and N2 respectively. The resource additions responsible for these higher portfolio costs do provide a benefit to overall portfolio emissions, but the efficiency of these emissions reductions per dollar spent are extremely low.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales are met by non-emitting/renewable resources by 2030, ramping up to 100 percent by 2045. Existing thermal plants continue to be in operation unless economically retired by the model. New peaking capacity resources remain an option for new resource selection. In order for the Mid Scenario portfolio to be 100 percent greenhouse gas neutral by 2030, an estimate for alternative compliance costs is calculated starting in 2030 through 2044. In Sensitivity N, all existing thermal plants are retired by 2030 regardless of economic viability. New peaking capacity resources are also removed for new resource selection. The CETA target is adjusted to 100 percent renewable by 2030. This means the renewable energy target increases by 4.1 million MWhs, rising from 7.6 million MWhs in 2030 to 11.7 million MWhs as shown in Figure 8-70.

Sensitivity N modeled two slightly different sets of assumptions. The first iteration, Sensitivity N1, used the model constraints provided above. Sensitivity N1 allowed the portfolio model to optimize to the 100 percent CETA target by 2030 by whatever means necessary. The second iteration, Sensitivity N2, removed lithium-ion and flow batteries from the available resources. Sensitivity N2 forced the model to solve using pumped hydro storage as the primary storage technology.

Figure 8-83: Renewable Targets – Mid Scenario and Sensitivity N1 and N2 Portfolios

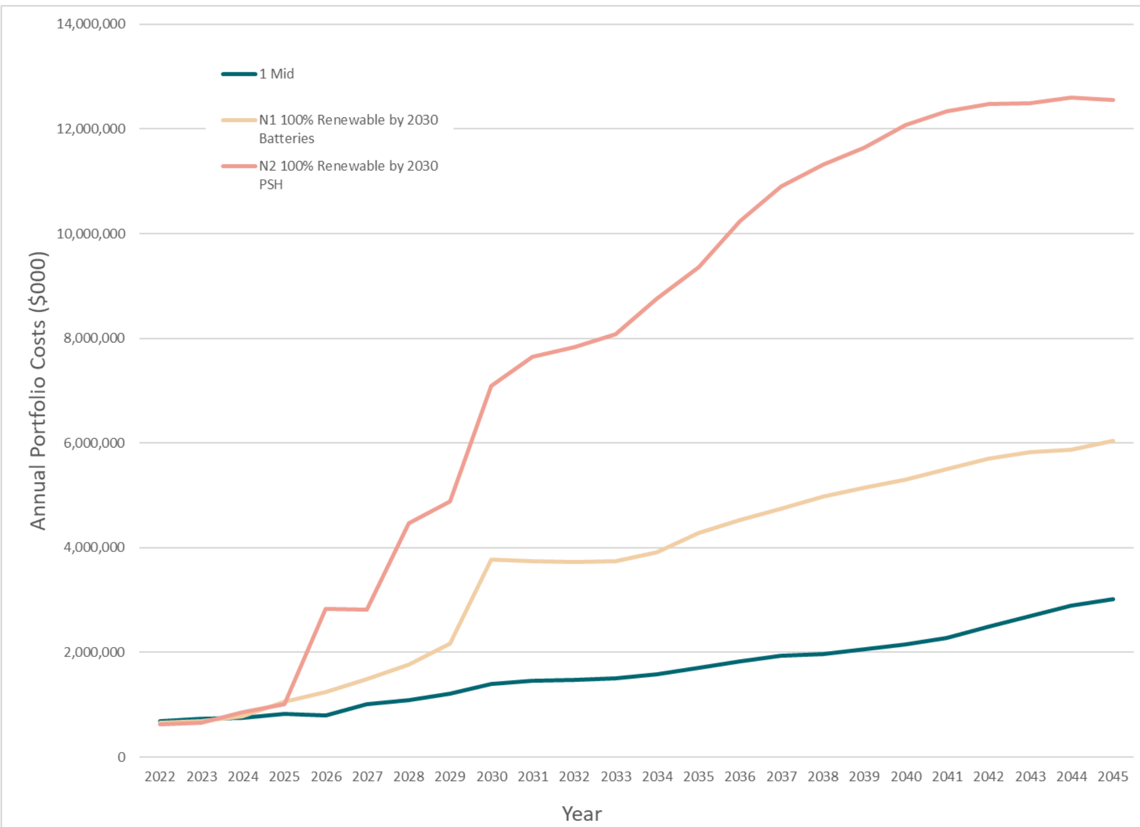


PORTFOLIO COSTS. Sensitivity N demonstrates that aggressively meeting CETA targets ahead of schedule may be possible with existing technologies, but that the cost to do so is high. The increase in costs for Sensitivity N is due to the increase in overall resource builds, particularly for storage resources. Both variations of Sensitivity N have lower SCGHG compared to the Mid Scenario; however, both variations also are among the most expensive portfolios modeled as part in the 2021 IRP. Figures 8-84 and 8-85 compare the breakdown of costs between the Mid Scenario and Sensitivity N portfolios.

Figure 8-84: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity N1 and N2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
N1	100% Renewable by 2030 (Batteries)	$32.03	$3.76	$35.79	$15.17
N2	100% Renewable by 2030 (PHES)	$66.64	$2.52	$69.16	$33.37

Figure 8-85: Annual Portfolio Costs – Mid Scenario and Sensitivity N1 and N2



RESOURCE ADDITIONS. Figures 8-86 and 8-87 compare the nameplate capacity additions of the Sensitivity N and Mid Scenario portfolios. By 2025, Sensitivity N1 has built a large amount of wind and Sensitivity N2 has built a large amount of solar (both standalone and hybrid) to replace the energy from retirements of Colstrip and Centralia, as well as to meet the high CETA renewable need. Through 2030, Sensitivity N1 selects a portfolio composed largely of 2-hour lithium-ion batteries and wind, whereas Sensitivity N2 selects a more diversified set of resources, adding pumped hydro as a storage resource and a mix of solar and wind projects. At the end of planning period, storage resources compose 78 percent and 71 percent of the resource capacity for Sensitivities N1 and N2 respectively. These massive investments in storage dwarf the resource additions selected in the Mid Scenario, resulting in exorbitant portfolio costs.

Figure 8-86: Portfolio Additions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

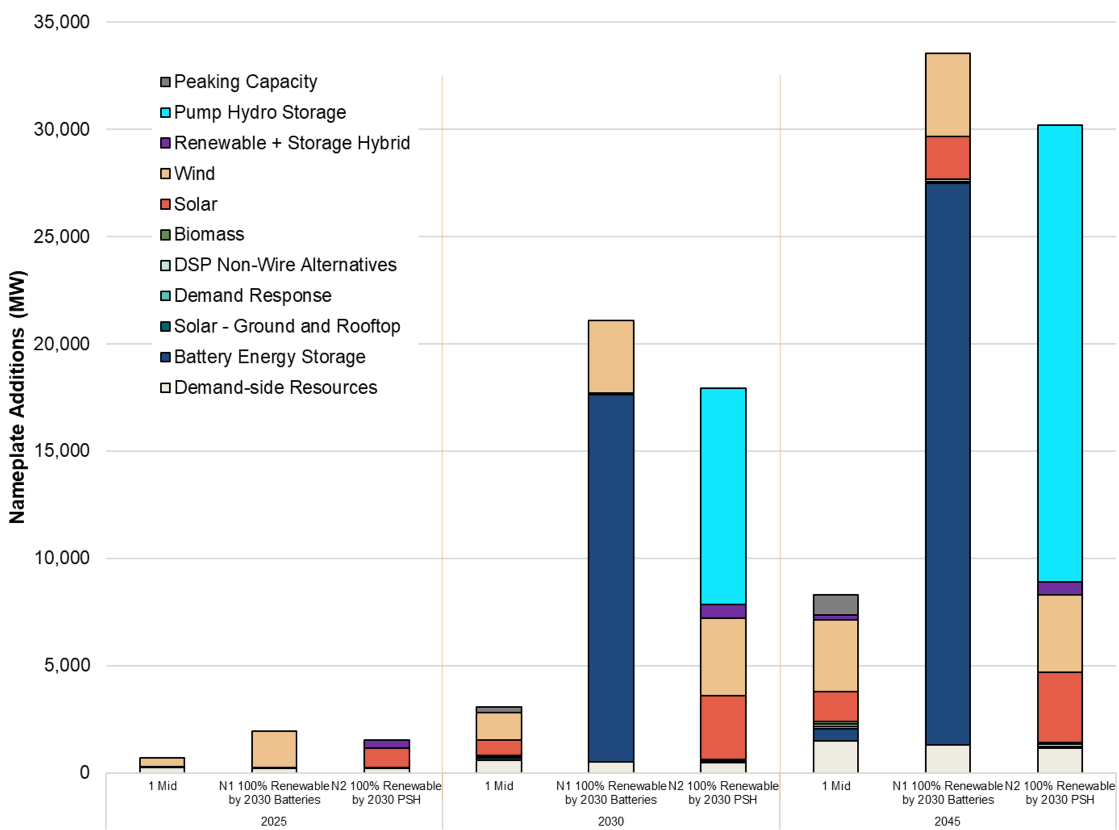


Figure 8-87: Portfolio Additions by 2045 – Sensitivity N, 100% Renewable by 2030

Resource Additions by 2045	1 Mid	N1 100% Renewable by 2030 - Batteries	N12100% Renewable by 2030 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,169 MW
Battery Energy Storage	550 MW	26,200 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	59 MW	59 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,844 MW	6,943 MW
Biomass	90 MW	0 MW	75 MW
Solar	1,393 MW	1,994 MW	3,268 MW
Wind	3,350 MW	3,850 MW	3,600 MW
Renewable + Storage Hybrid	250 MW	0 MW	622 MW
Pumped Hydro Storage	0 MW	0 MW	21,300 MW
Peaking Capacity	948 MW	0 MW	0 MW

EMISSIONS. Figure 8-88 compares the direct GHG emissions from the Sensitivity N variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2030, the emissions for Sensitivity N drop to zero at 2030. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able to charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-88: Direct GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

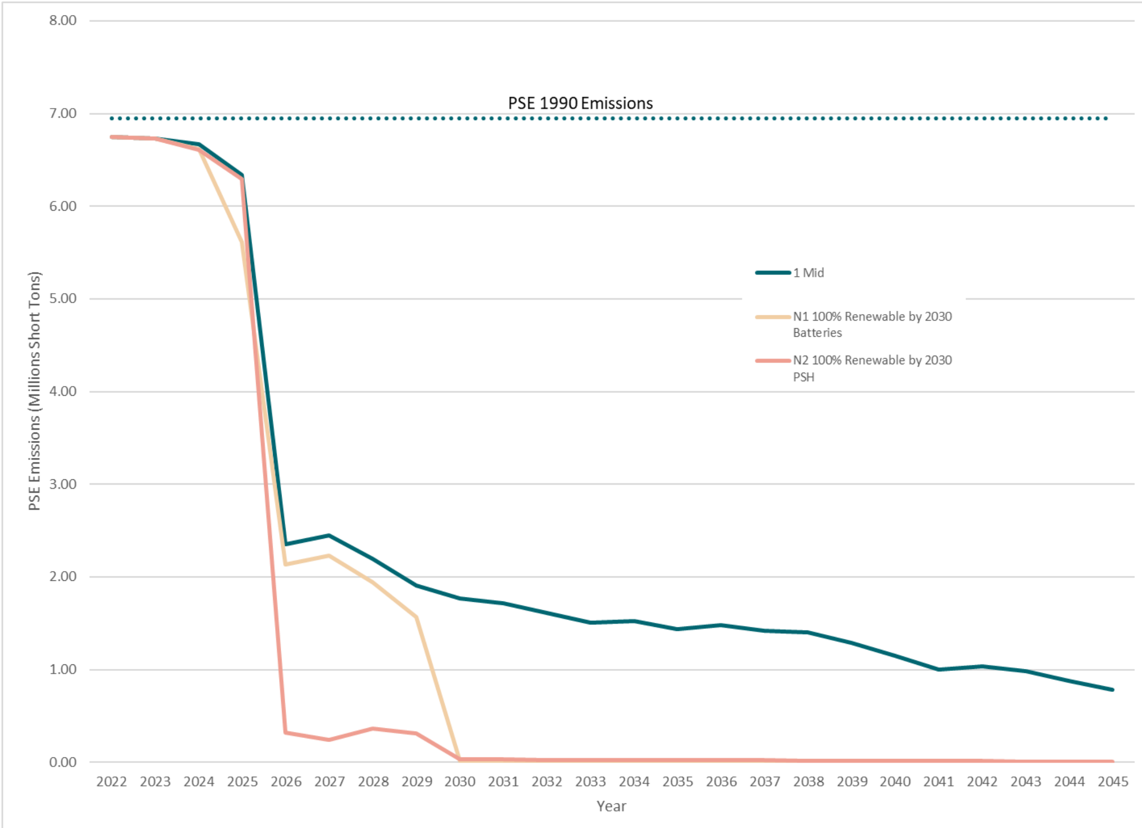
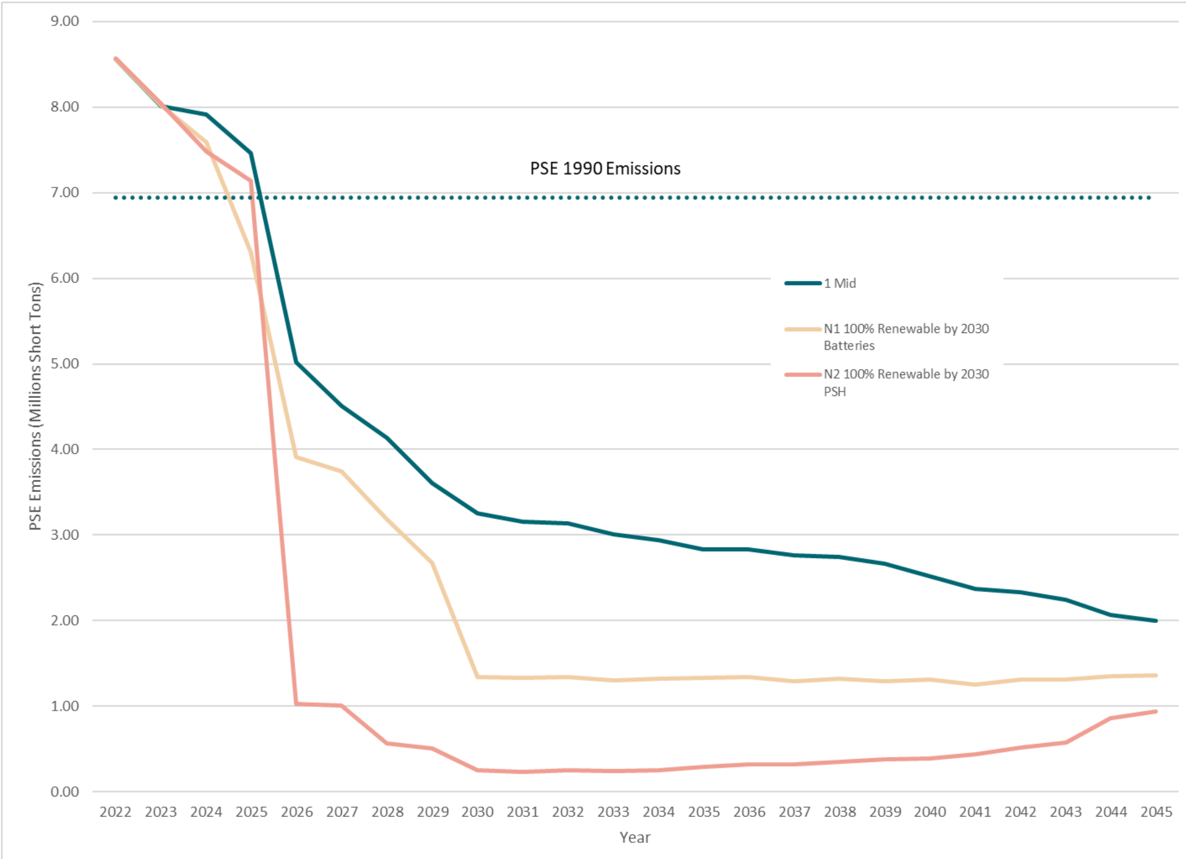


Figure 8-89 compares GHG emissions from the Sensitivity N1 and N2 variations with the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity N emissions are lower than Mid Scenario emissions throughout the planning horizon, but it is interesting to note that emissions start to increase again for both Sensitivities N1 and N2 in the later years of the planning period due to the increase in energy purchased from market to fill the growing demand from storage resources.

Figure 8-89: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030



To put emission reductions in perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions -\ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-90 shows the results of this calculation for the Sensitivity N variations and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity N variations are an order of magnitude higher than the preferred portfolio, which suggests that forcing 100 percent renewable energy by 2030 is not an efficient means to reduce emissions.

Figure 8-90: Cost of Emissions Reduction – Mid Scenario, Sensitivity N and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

O. 100% Renewable by 2045

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that has no natural gas-fired generation resources by 2045.

Baseline: No planned retirements of existing gas fired generation resources; however, the model allows for economic retirement.
Sensitivity > All existing natural gas-fired resources, including new peaking capacity resources, must be retired by 2045.

KEY FINDINGS. Sensitivity O shows that it is possible to phase out natural gas generation by the year 2045. However, the capital cost to do so it very high. On the basis of tons of GHG emissions reduced per dollar, there are more efficient ways to achieve comparable emissions reductions. Sensitivity O also shows the importance of market purchases to supporting a storage-heavy portfolio in a cost-effective manner.

ASSUMPTIONS. In the Mid Scenario portfolio, existing natural gas-fired generation resources remain in operation unless economically retired by the model. Generic peaking capacity resources are available as a new resource, but they retire by 2045. In Sensitivity O, all existing natural gas-fired generation resources are retired by 2045, regardless of economic viability. Existing thermal plant retirements are ramped in over time at a rate of approximately 200 MW per year between 2030 and 2045 to create a smoother transition to renewable generation.

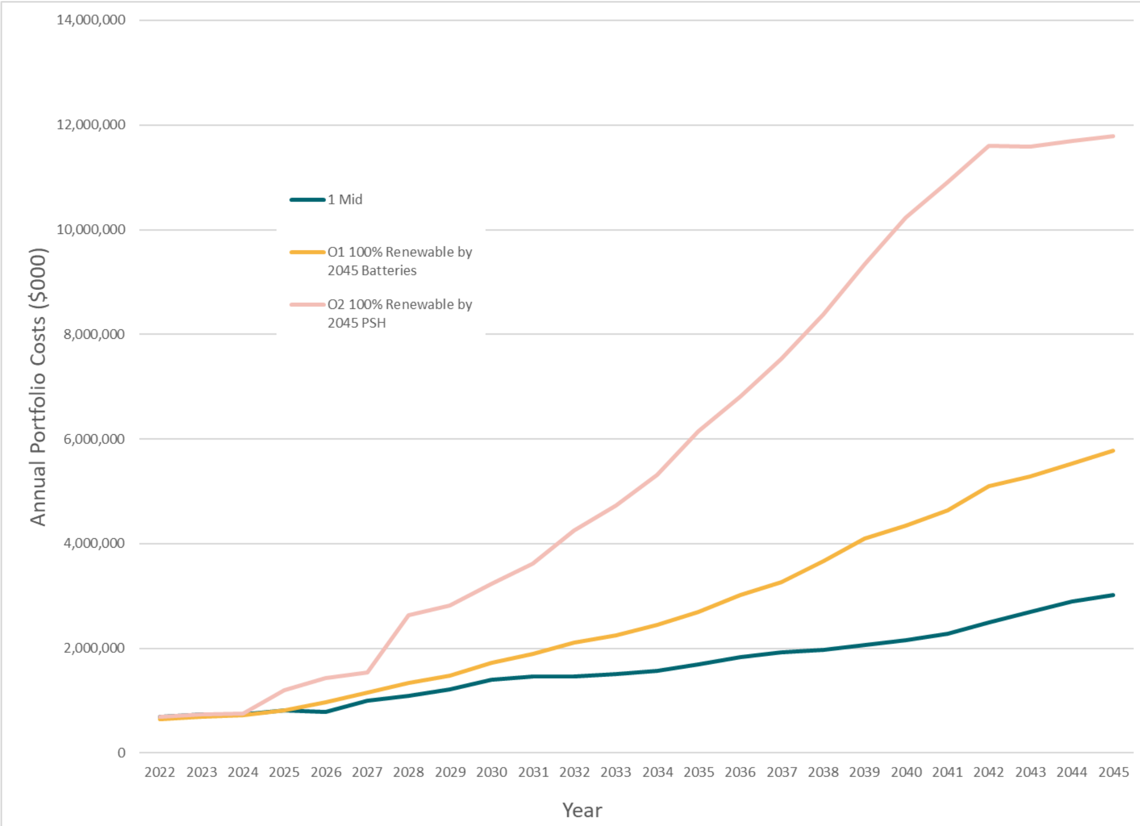
Sensitivity O modeled three slightly different sets of assumptions. The first iteration, Sensitivity O1, used the model constraints provided above and allowed the model to optimize removing natural gas fueled resource by 2045. The second iteration, Sensitivity O2, removed lithium-ion and flow batteries from the list of available resources and forced the model to solve using pumped hydroelectric storage as the primary storage technology.

PORTFOLIO COSTS. Figures 8-91 and 8-92 illustrate the breakdown of costs between the Mid Scenario and Sensitivity O portfolios. The increase in costs for Sensitivity O is attributed to the increase in the overall resource builds.

Figure 8-91: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity O1 and Sensitivity O2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
O1	100% Renewable by 2045 – Batteries	$23.35	$4.81	$28.16	$7.54
O2	100% Renewable by 2045 – PHES	$46.95	$3.98	$50.94	$30.32

Figure 8-92: Annual Portfolio Costs – Mid Scenario and Sensitivity O



RESOURCE ADDITIONS. Figures 8-93 and 8-94 compare the nameplate capacity additions of Sensitivity O and the Mid Scenario portfolios. Neither variation of Sensitivity O selects any flexible capacity resources over the course of the planning period. Both variations focus on building storage resources early and often to keep up with growing capacity need. Sensitivity O1 builds solely standalone 2-hour lithium-ion batteries, whereas Sensitivity O2 builds a mix of pumped hydroelectric storage and hybrid resources. Both variations rely heavily on market purchases to charge storage resources throughout the planning period.

Figure 8-93: Portfolio Additions – Mid Scenario and Sensitivity O

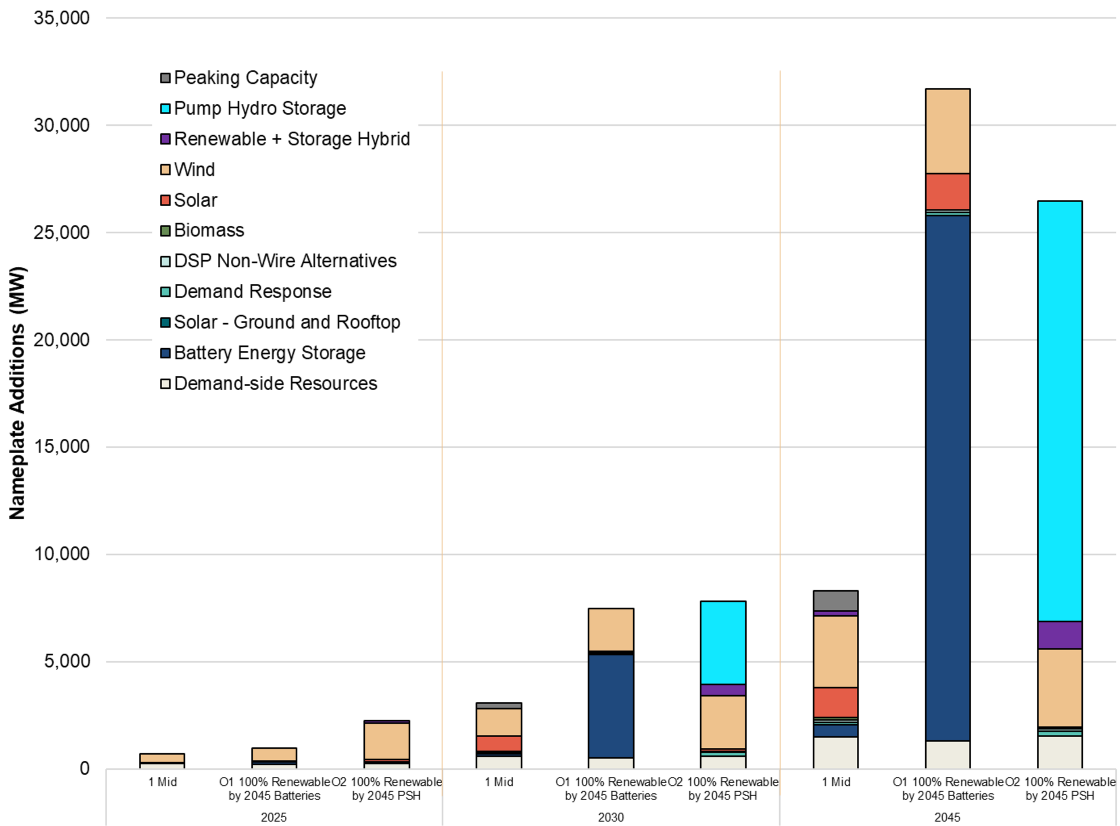


Figure 8-94: Portfolio Additions by 2045 – Mid Scenario and Sensitivity O, – 100% Renewable by 2045

Resource Additions by 2045	1 Mid	O1 100% Renewable by 2045 - Batteries	O2 100% Renewable by 2045 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,537 MW
Battery Energy Storage	550 MW	24,500 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	128 MW	204 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,642 MW	3,749 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	1,692 MW	99 MW
Wind	3,350 MW	3,950 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	0 MW	1,249 MW
Pumped Hydro Storage	0 MW	0 MW	19,600 MW
Peaking Capacity	948 MW	0 MW	0 MW

PEAK CAPACITY. The results of Sensitivity O are somewhat conflicted. On one hand, Sensitivity O1 just barely exceeds the peak capacity need in the year 2045 as shown in Figure 8-95. On the other hand, Sensitivity O2 was significantly over-built, exceeding peak need by over 5,000 MW in 2045 as shown in Figure 8-83. These two extremes make the results difficult to interpret with confidence. It seems unlikely that many small 2-hour storage resources are the most effective resources to meet peak need without the aid of thermal resources. However, Sensitivity O1 was far less costly than Sensitivity O2, which included seemingly more flexible 8-hr storage resources. Sensitivity O placed extreme demands on the simulation to dispatch over 10,000 MW of storage capacity and to replace over 2,000 MW of existing thermal resources in a single year. More work is required to refine storage logic within the portfolio model.

Figure 8-95: Peak Capacity Contribution – Mid Scenario and Sensitivity O1, 100% Renewable by 2045 – Batteries

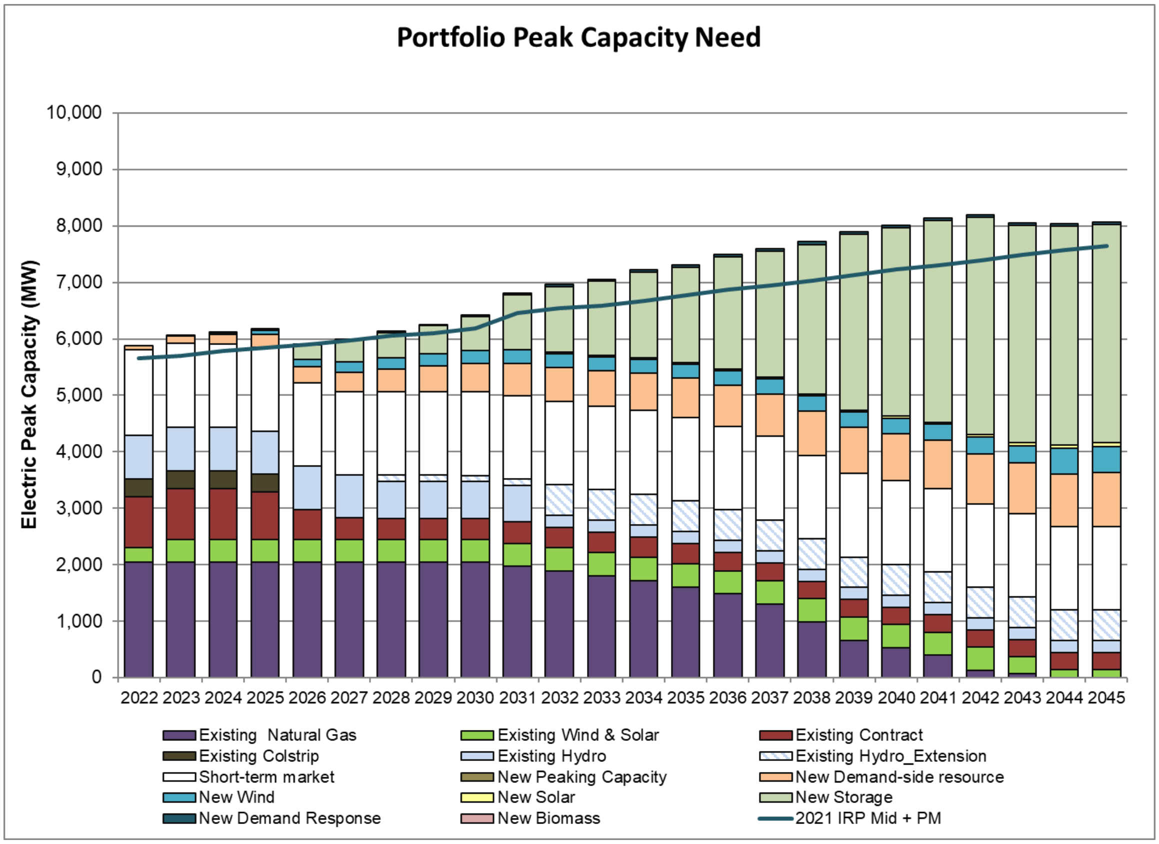
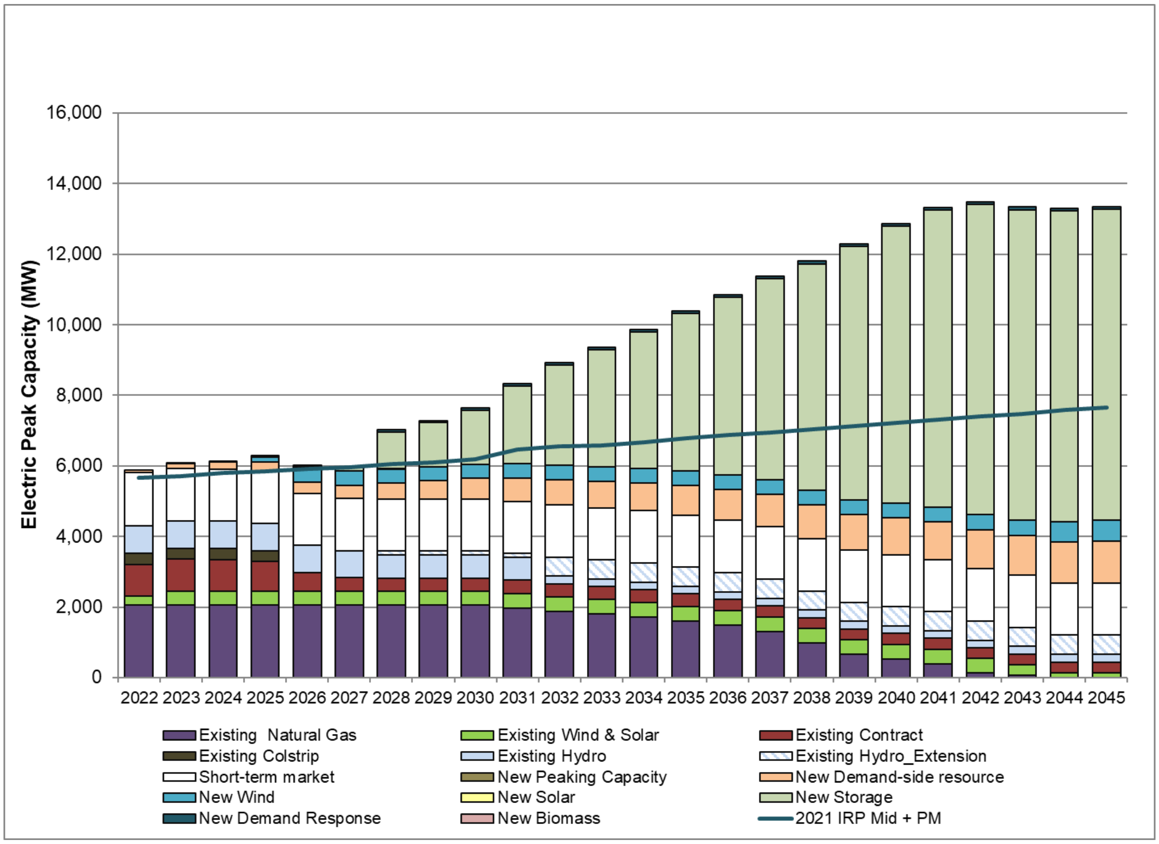


Figure 8-96: Peak Capacity Contribution – Mid Scenario and Sensitivity O2 – 100% Renewable by 2045 – Pumped Hydro Storage



EMISSIONS. Figure 8-97 compares the direct GHG emissions from the Sensitivity O variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2045, the emissions for Sensitivity O drop to zero by 2045. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-97: Direct GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045

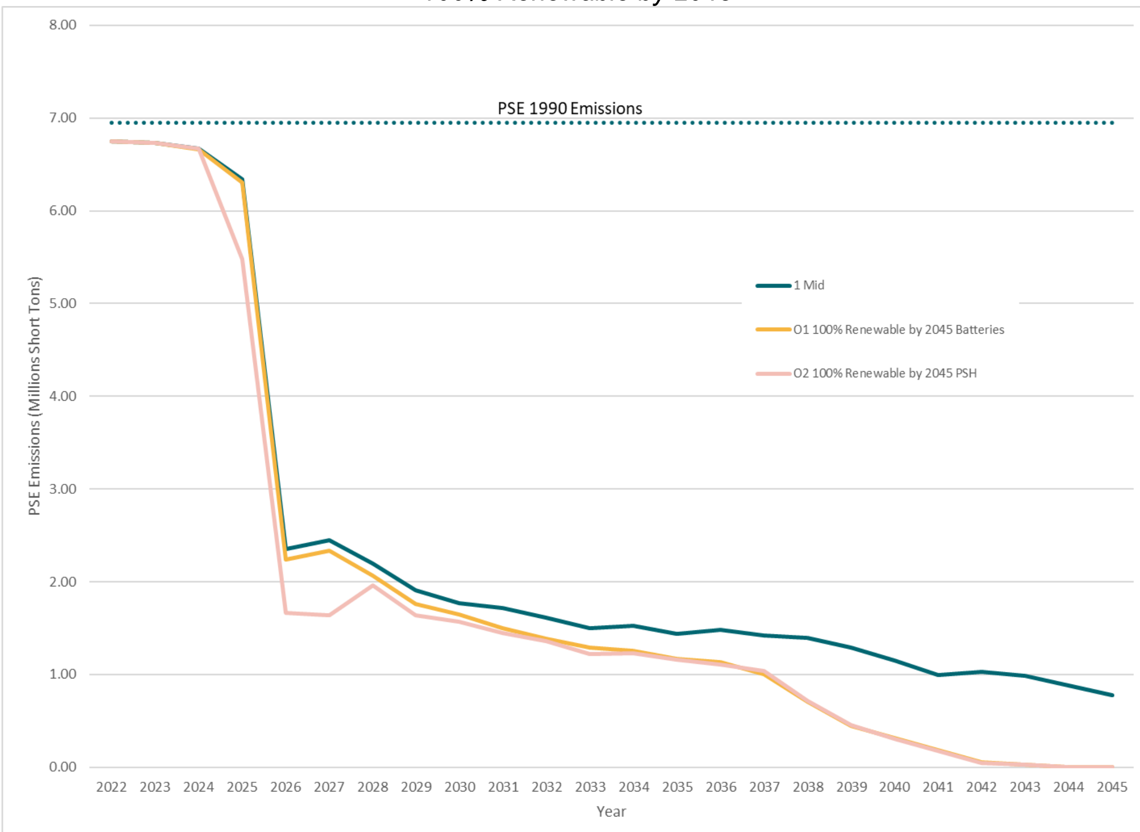
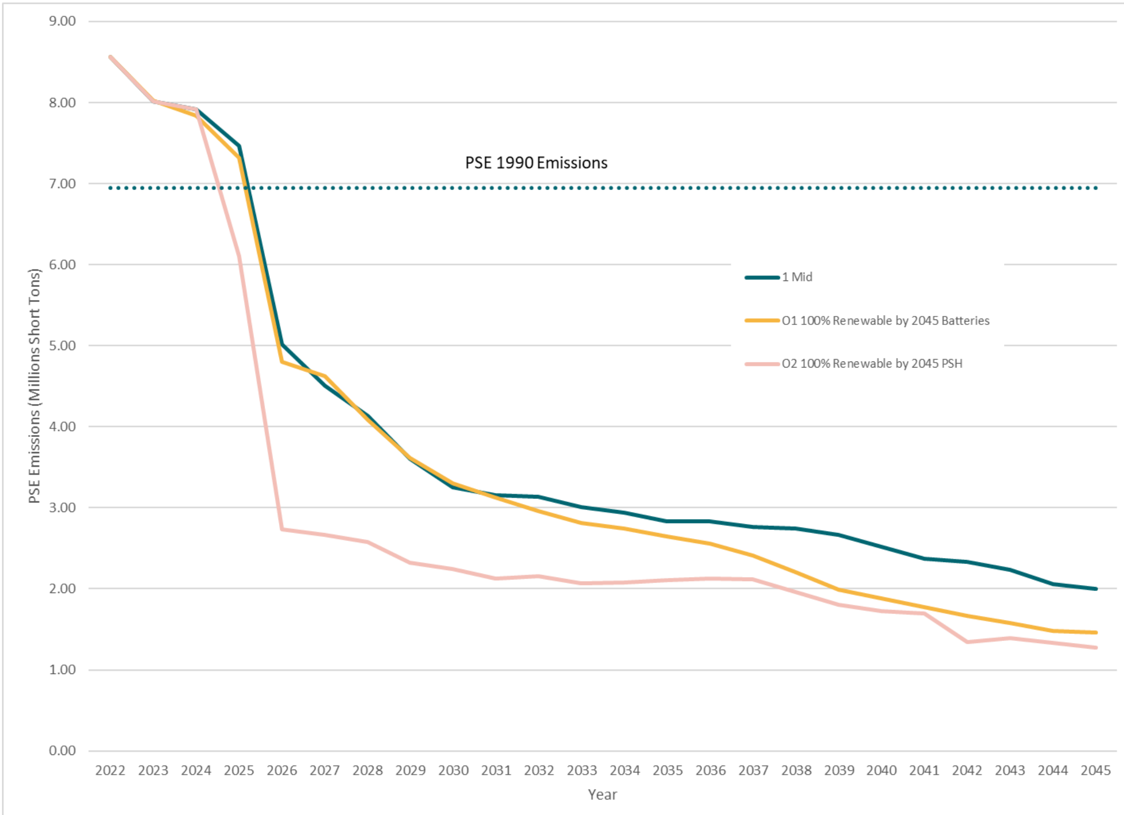


Figure 8-98 provides a view of GHG emissions from the Sensitivity O variations compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity O emissions are still lower than Mid Scenario emissions throughout the planning horizon.

Figure 8-98: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045



To put emission reductions into perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-99 shows the results of this calculation for Sensitivity O and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity O variations are an order of magnitude larger than the preferred portfolio, suggesting that forcing out natural gas generation is not an efficient means to reduce emissions.

Figure 8-99: Cost of Emissions Reduction – Mid Scenario, Sensitivity O and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
O1 100% Renewable by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Renewable by 2045 - PHES	43.54	$46.95	3.04
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

P. No New Thermal Resources Before 2030

This sensitivity provides insight into how energy storage provides value to a system that has traditionally been provided by natural gas plants.

Baseline: Thermal peaking capacity resources may be added to the portfolio as early as 2025**.**
Sensitivity P > No thermal peaking capacity may be added to the portfolio until 2030, thereby requiring the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need.

KEY FINDINGS. In Sensitivity P, delaying the availability of peaking capacity resources resulted in much earlier addition of storage resources and the addition of fewer peaking capacity resources. However, these changes increased portfolio costs by $7 to $25 billion depending on the type of storage resource selected. Furthermore, Sensitivities P1 and P3 showed no reduction in GHG emissions compared to the Mid Scenario. Sensitivity P2 did show a small reduction in GHG emissions, but the emission reduction efficiency was quite low compared to other portfolios such as the preferred portfolio.

ASSUMPTIONS. In the Mid Scenario portfolio, peaking capacity resources are available as early as 2025. In Sensitivity P, peaking capacity resources are available much later, in 2030. This forces the model to optimize its resource selection of energy storage, renewable resources and demand-side resources to keep the portfolio balanced until peaking capacity resources are available.

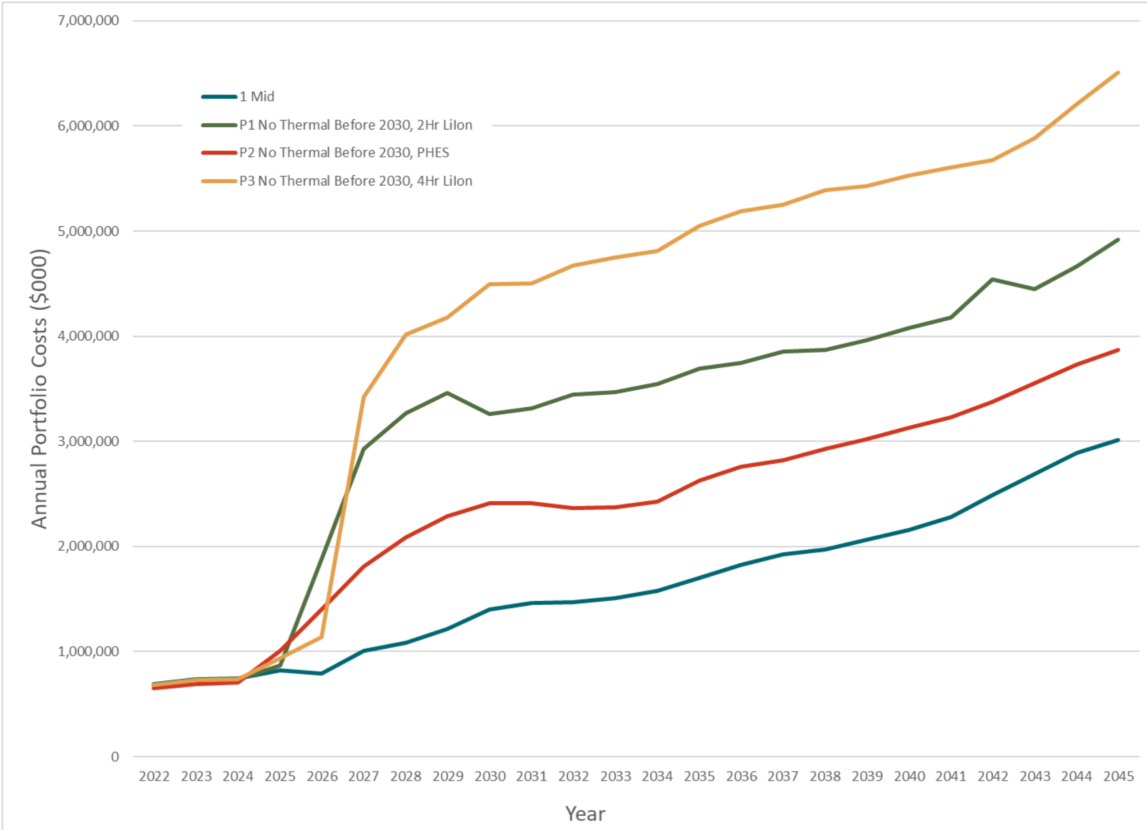
To gain an understanding of how the model reacts to different storage resources, three variations on Sensitivity P were run. Sensitivity P1 used the model constraints described above and allowed the model to select the most cost-effective storage resource in the period 2022 to 2030; the model selected 2-hour lithium-ion batteries. Sensitivity P2 removed lithium-ion and flow batteries from the list of available resources before 2030 and forced the model to solve using pumped hydroelectric storage as the primary storage technology. Sensitivity P3 removed 2-hour lithium-ion batteries from the available resources before 2030, and forced the model to select the next most cost-effective storage resource to meet capacity need before 2030; then the model selected 4-hour lithium-ion batteries.

PORTFOLIO COSTS. Figures 8-100 and 8-101 illustrate the breakdown of costs between the Mid Scenario and Sensitivities P1, P2 and P3. Annual portfolio costs are significantly higher for all variations of Sensitivity P compared to the Mid Scenario. Storage resources and demand response programs are more expensive options than peaking capacity resources. All variations of Sensitivity P added over 2,500 MW more nameplate capacity of new resources compared to the Mid Scenario, resulting in higher portfolio costs. A significant amount of batteries and pumped hydro energy storage was added to both portfolios between 2025 and 2030 causing the spike in annual portfolio costs.

Figure 8-100: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity P

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
P1	No New Thermal Resources – 2-hr Li-Ion	$30.84	$6.38	$37.22	$16.60
P2	No New Thermal Resources – PHES	$22.85	$4.77	$27.62	$7.00
P3	No New Thermal Resources – 4-hr Li-Ion	$39.01	$6.69	$45.70	$25.08

Figure 8-101: Annual Portfolio Costs – Mid Scenario and Sensitivity P



RESOURCE ADDITIONS. Figures 8-102 and 8-103 compare the nameplate capacity additions of the portfolios in Sensitivities P1, P2 and P3 and the Mid Scenario. The Mid Scenario portfolio added 237 MW of peaking capacity resources in 2026 as Colstrip and Centralia were removed. It would take about 3,800 MW nameplate capacity of batteries to equal those new peaking capacity resources since 2-hour lithium-ion batteries have only a 12.4 percent ELCC. Sensitivity P1 selected 3,775 MW of 2-hour lithium-ion batteries to make up for the absence of new peaking capacity resources. Similar resources are added in the other variations of Sensitivity P, the only difference being the addition of alternative storage resources (pumped hydroelectric storage and 4-hour lithium-ion batteries).

All three Sensitivity P portfolios added a significant amount of 2-hour lithium-ion battery resources. Sensitivity P1 selected 2-hour lithium-ion batteries as the most cost-effective resource and built nearly exclusively 2-hour lithium ion batteries, except for 25 MW of 4-hour lithium-ion batteries in the year 2045. Sensitivity P2 was forced to select pumped hydro storage as the initial storage technology; after 2030, no new pumped hydro storage was added, but 1,025 MW of 2-hour lithium-ion batteries were added. Similarly, Sensitivity P3 was forced to select 4-hour lithium-ion batteries as the initial storage technology; after 2030 no new 4-hour batteries were added, but 875 MW of 2-hour lithium-ion batteries were added to the portfolio.

By the end of the planning period, Sensitivity P1 had built 474 MW of peaking capacity, about half of the peaking capacity selected in the Mid Scenario. The large capacity storage resources (PHES and 4-hour lithium-ion batteries) built far less peaking capacity, with Sensitivity P2 building only 18 MW of peaking capacity and Sensitivity P3 building none at all.

Figure 8-102: Portfolio Additions – Mid Scenario and Sensitivity P

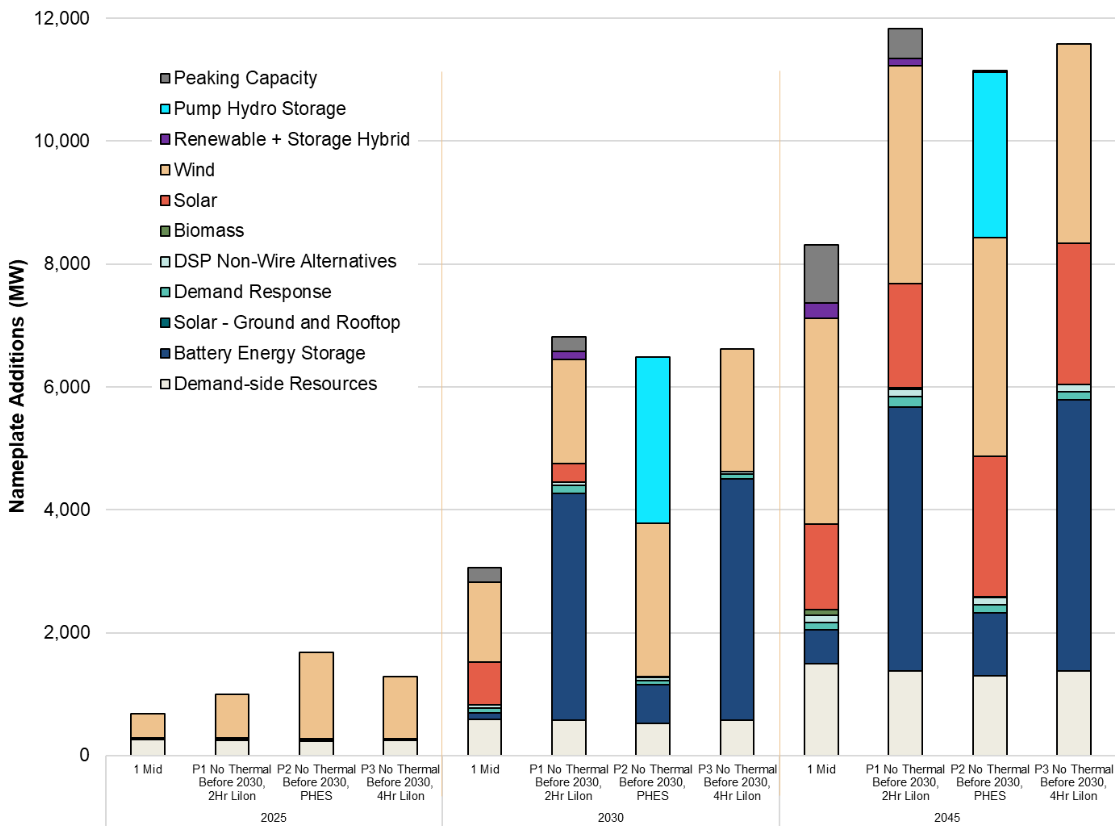
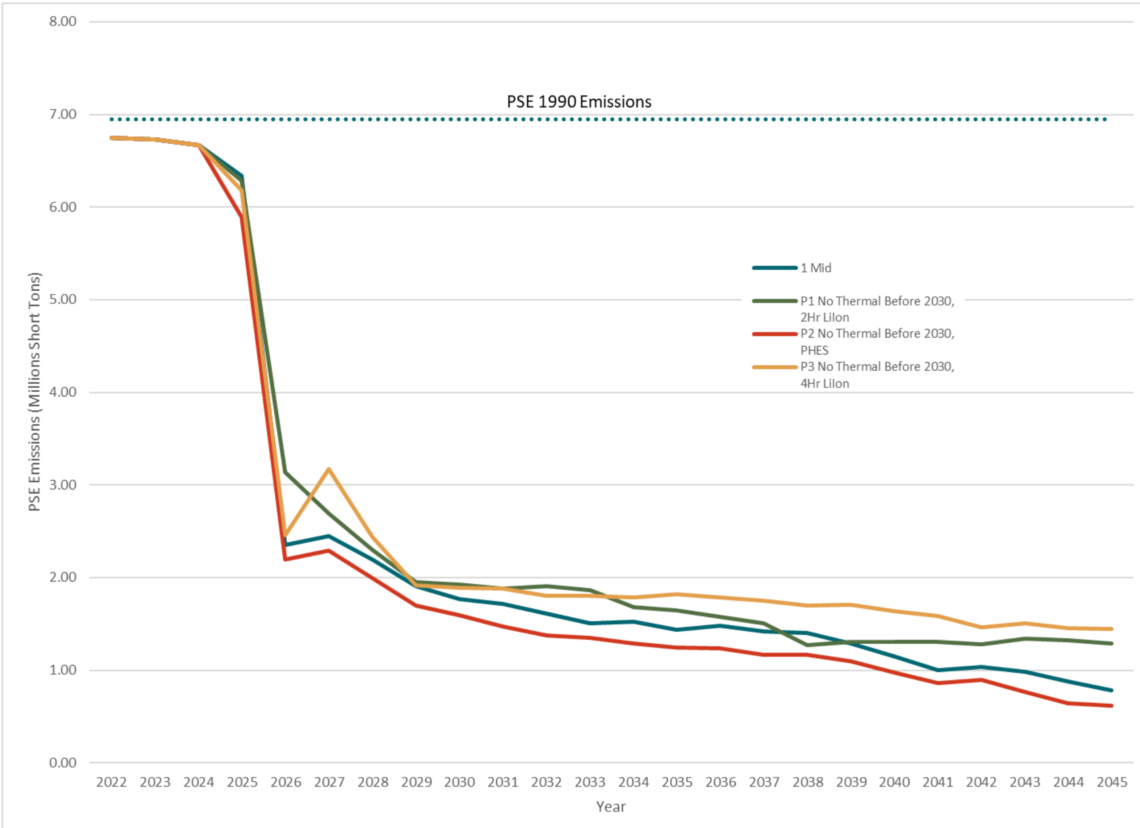


Figure 8-103: Portfolio Additions by 2045 – Mid Scenario and Sensitivity P, No New Thermal Before 2030

Resource Additions by 2045	1 Mid	P1 No New Thermal – 2hr Li-Ion	P2 No New Thermal – PHES	P3 No New Thermal – 4hr Li-Ion
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,372 MW
Battery Energy Storage	550 MW	4,300 MW	1,025 MW	4,425 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	178 MW	122 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,260 MW	5,859 MW	5,542 MW
Biomass	90 MW	15 MW	15 MW	0 MW
Solar	1,393 MW	1,695 MW	2,294 MW	2,292 MW
Wind	3,350 MW	3,550 MW	3,550 MW	3,250 MW
Renewable + Storage Hybrid	250 MW	125 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	2,700 MW	0 MW
Peaking Capacity	948 MW	474 MW	18 MW	0 MW

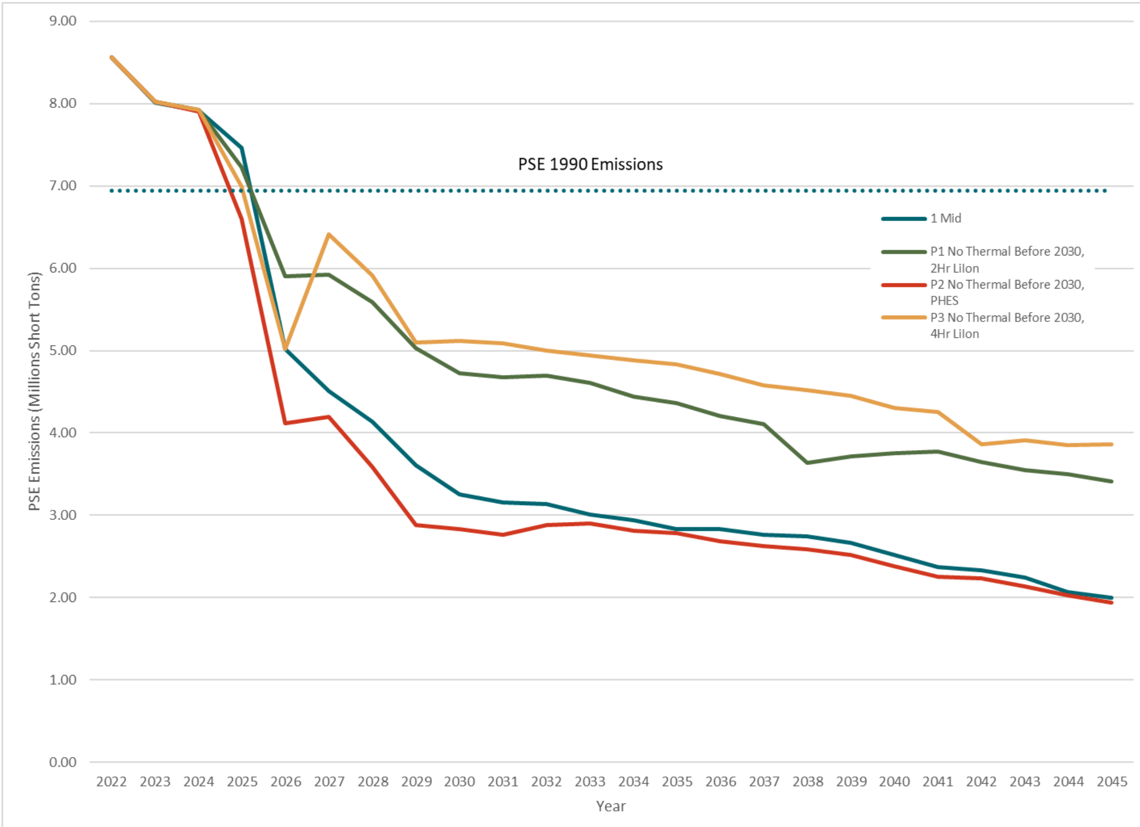
OTHER FINDINGS. Figure 8-104 compares the direct GHG emissions from the Sensitivity P variations with to the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Despite fewer peaking capacity resources built over the planning period, Sensitivities P1 and P3 have higher direct GHG emissions compared to the Mid Scenario due increased dispatch of existing thermal resources over the planning period. Existing thermal resources are not as efficient as new peaking resources and therefore generate greater emissions.

Figure 8-104: Direct GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



When storage is a major component of a resource portfolio, indirect emissions from market purchases increase. Storage resources may charge from market purchases and these unspecified market purchases are tagged with a GHG emission rate per CETA rules. Figure 8-105 provides a view of GHG emissions from the Sensitivity P variations as compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivities P1 and P3 are now significantly higher emitters than the Mid Scenario, and Sensitivity P3 has nearly the same emission rate as the Mid Scenario. The increase in emissions from portfolios P1 and P3 comes from an increase in dispatch from the existing natural gas resources.

Figure 8-105: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



To put emission reductions into perspective, it is useful to look at the reduction in emissions as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-106 shows the results of this calculation for Sensitivity P and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. For Sensitivities P1 and P3, both the cost of the portfolio and the levelized quantity emissions were greater than the Mid Scenario, which by definition means they are not feasible plans for reducing emissions. Sensitivity P2 did result in a small reduction in emissions, but the cost of emissions reduction is much higher than in the preferred portfolio, suggesting that replacing the new peaker with storage is not an effective means to reduce emissions.

Figure 8-106: Cost of Emissions Reduction – Mid Scenario, Sensitivity P and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

Demand Forecast Adjustments

Q. Fuel Switching, Gas to Electric

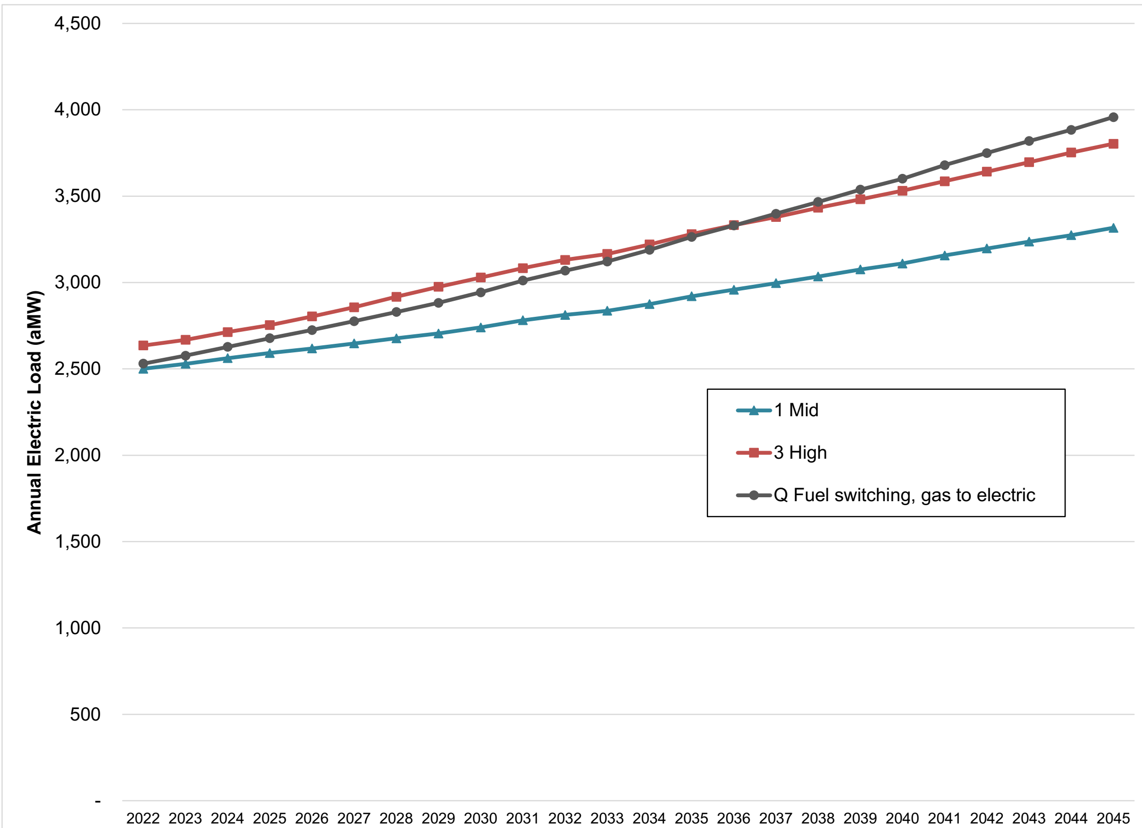
Natural gas is often used for space heating, water heating, cooking, industrial process heat and feedstocks and other uses in residential, commercial and industrial settings. Recent trends in local legislation limit the use of natural gas for these purposes in new construction. Sensitivity Q explores how the energy environment may change if electricity was used as an energy supply in place of the current uses of natural gas.

Baseline: The Mid Scenario assumes the IRP Base Demand Forecast.
Sensitivity R > Sensitivity Q modifies the demand forecast to simulate substitution of electricity for current uses of natural gas in PSE's service area.

KEY FINDINGS. Incorporating a higher penetration of electrification changed the key modeling assumptions for the portfolio and produced a higher electric demand forecast, higher CETA renewable need and a higher peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity Q selected higher resource builds and had higher portfolio costs compared to the Mid Scenario. More capacity was added in nearly every resource category to meet the increased demand forecast.

ASSUMPTIONS. The demand forecast is adjusted to add a transition from natural gas to electricity for end uses in the PSE service territory resulting in a higher electric demand forecast. PSE hired Cadmus to develop the adjusted electric load which assumes an increase in energy of 203 aMW in 2030 to 641 aMW by 2045 from the Mid Scenario. Figure 8-107 shows the annual electric load (aMW) used for Sensitivity Q compared to the Mid and High Scenarios. In comparison to the electric load in the High Scenario, the electric load for Sensitivity Q is lower through 2036, then higher by 154 aMW by 2045. More information on the load conversion assumptions can be found in Appendix E, Conservation Potential Assessment.

Figure 8-107: Electric Energy Demand Forecast for the Mid and High Scenario Compared to Sensitivity Q (Electrification) Demand Forecast (aMW)

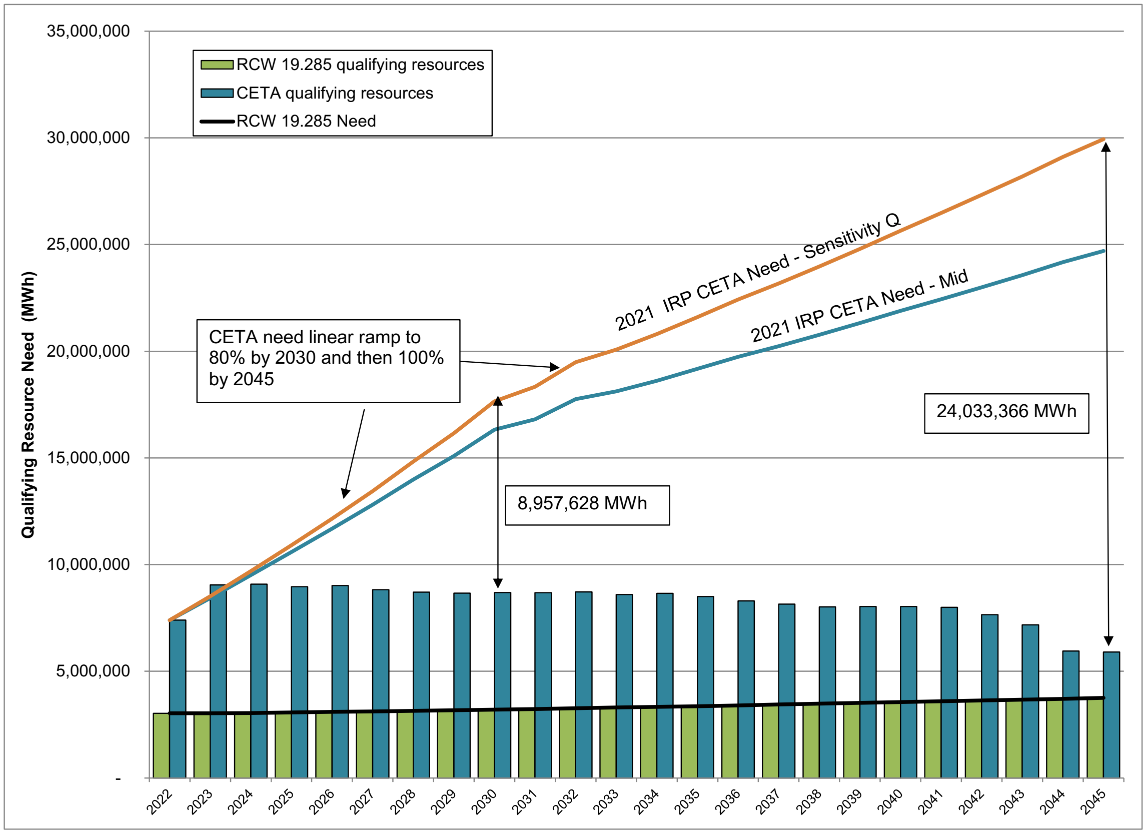


The increased electric demand requires additional CETA-compliant electricity above the Mid Scenario. To reflect this increased electric demand, the CETA renewable need is updated to reflect the change in the electric demand forecast. Figures 8-108 and 8-109 show the CETA renewable need for Sensitivity Q compared to the Mid Scenario. In Sensitivity Q, the CETA renewable need in 2045 is 24 million MWhs, an increase of 5.2 million MWhs from the Mid Scenario.

Figure 8-108: CETA Renewable Need – Mid Scenario and Sensitivity Q by 2030 and 2045

		CETA Renewable Need (MWh)	
	Portfolio	2030	2045
1	Mid Scenario	7,632,507	18,797,944
Q	Fuel Switching, Gas to Electric	8,957,628	24,033,366

Figure 8-109: CETA Renewable Need – Mid Scenario and Sensitivity Q

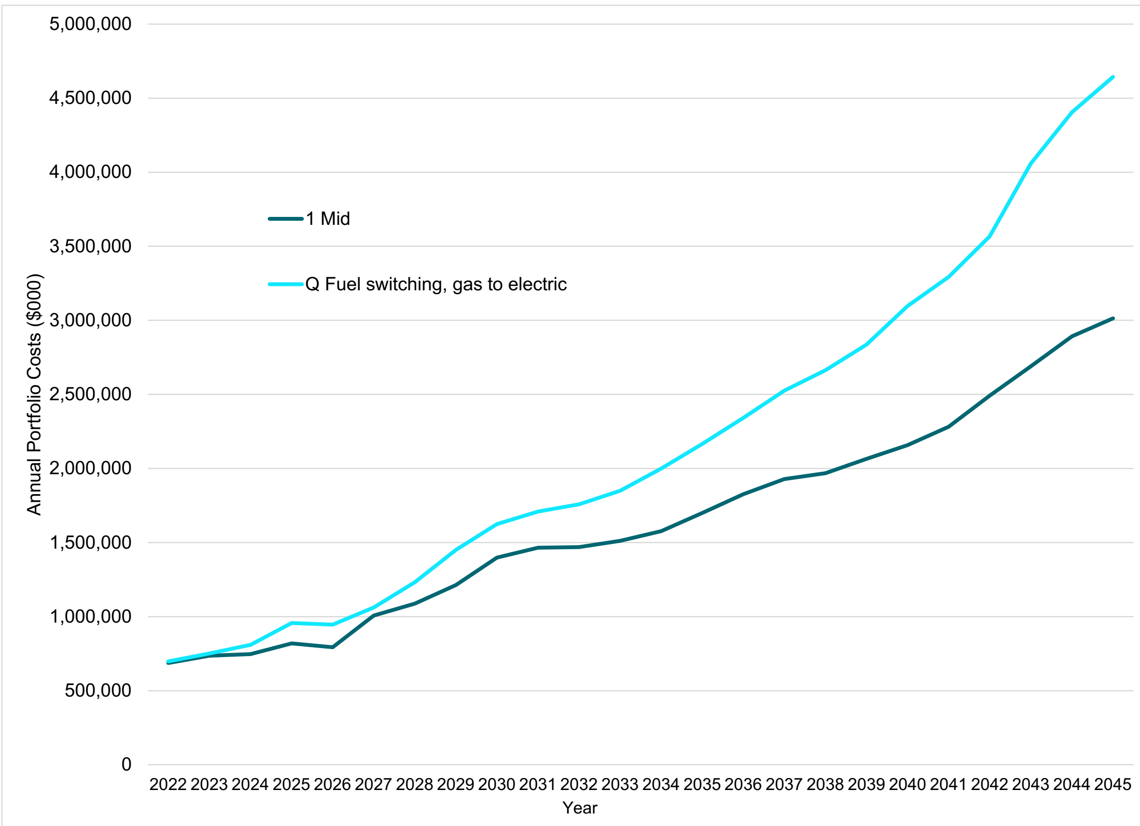


ANNUAL PORTFOLIO COSTS. Figures 8-110 and 8-111 illustrate the breakdown of portfolio costs between the Mid Scenario and Sensitivity Q. Due to the significant increase in electric demand and renewable need, costs for Sensitivity Q are much higher than the Mid Scenario. Additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs, are not included in this analysis.

Figure 8-110: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Q

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Q	Fuel Switching, Gas to Electric	$19.56	$5.60	$25.16	$4.54

Figure 8-111: Annual Portfolio Costs – Mid Scenario and Sensitivity Q



RESOURCE ADDITIONS. Figures 8-112 and 8-113 compare the nameplate capacity additions of Sensitivity Q and the Mid Scenario portfolios. Sensitivity Q added more capacity in nearly every resource category to meet the increased demand forecast, except for wind which shifted to an increase in Wind + Battery hybrid resource. Sensitivity Q selected conservation Bundle 11, whereas the Mid Scenario selected Bundle 10.

Figure 8-112: Portfolio Additions – Mid Scenario and Sensitivity Q

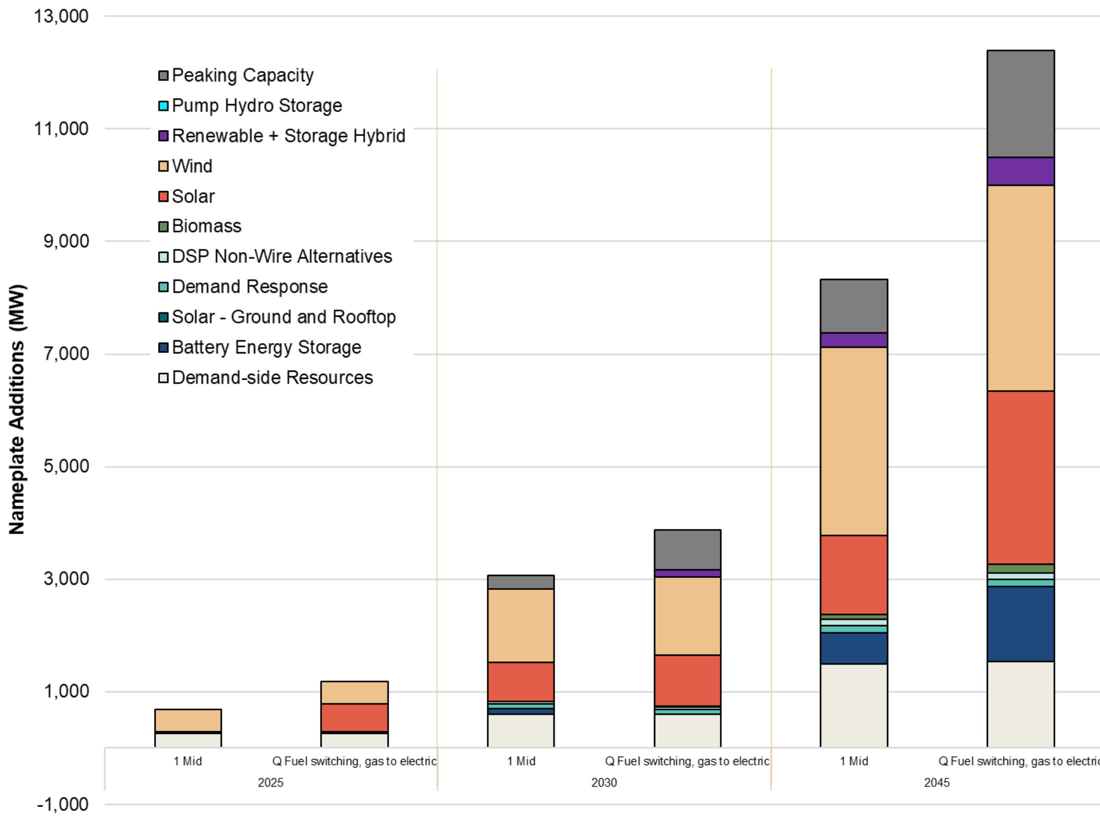
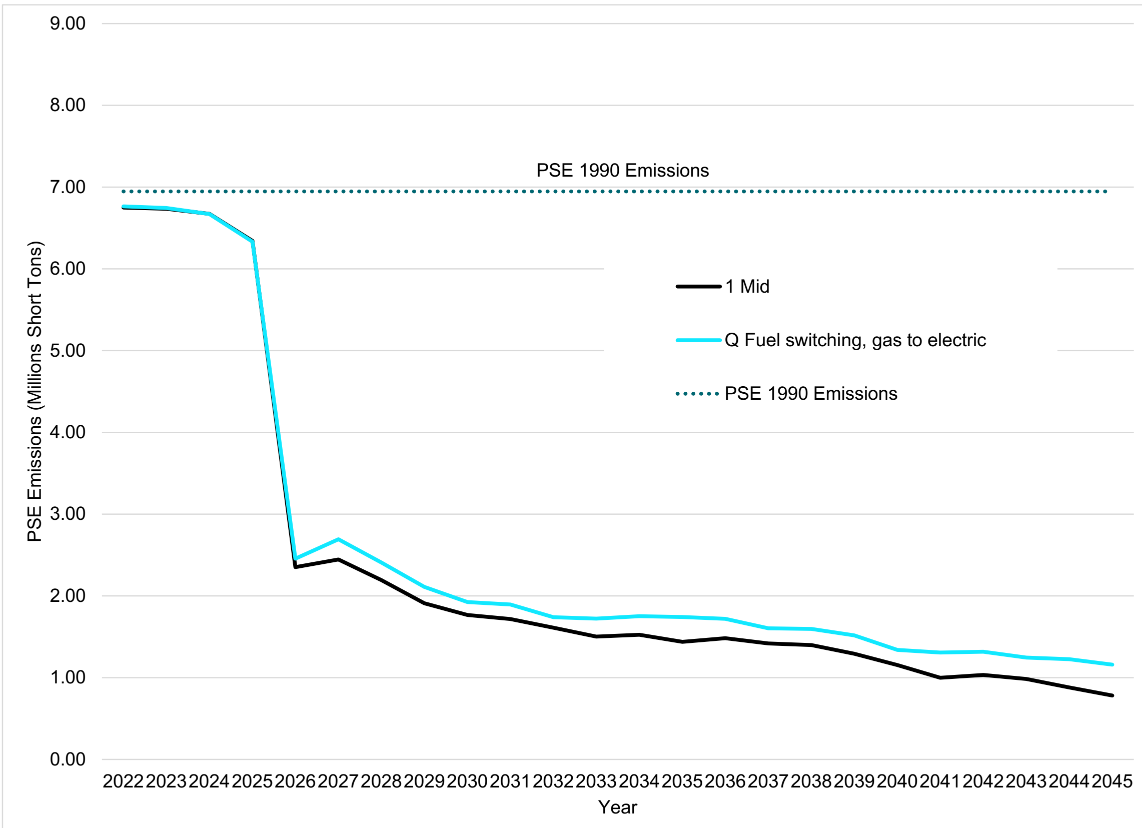


Figure 8-113: Portfolio Additions – Mid Scenario and Sensitivity Q

Resource Additions by 2045	1 Mid	Q Fuel Switching, Gas to Electric
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,325 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,888 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	3,088 MW
Wind	3,350 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW

EMISSIONS. The amount of peaking capacity resources doubled from 948 MW in the Mid Scenario to 1,896 MW in Sensitivity Q as result of the higher energy and peak need, despite increases in demand response and batteries. The higher dispatch from these flexible capacity resources produce a slightly higher overall emissions compared to the Mid Scenario. Figure 8-114 compares the emissions of the Mid Scenario and Sensitivity Q.

Figure 8-114: Direct GHG Emissions – Mid Scenario and Sensitivity Q



R. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity illustrate potential changes in PSE's load profile.

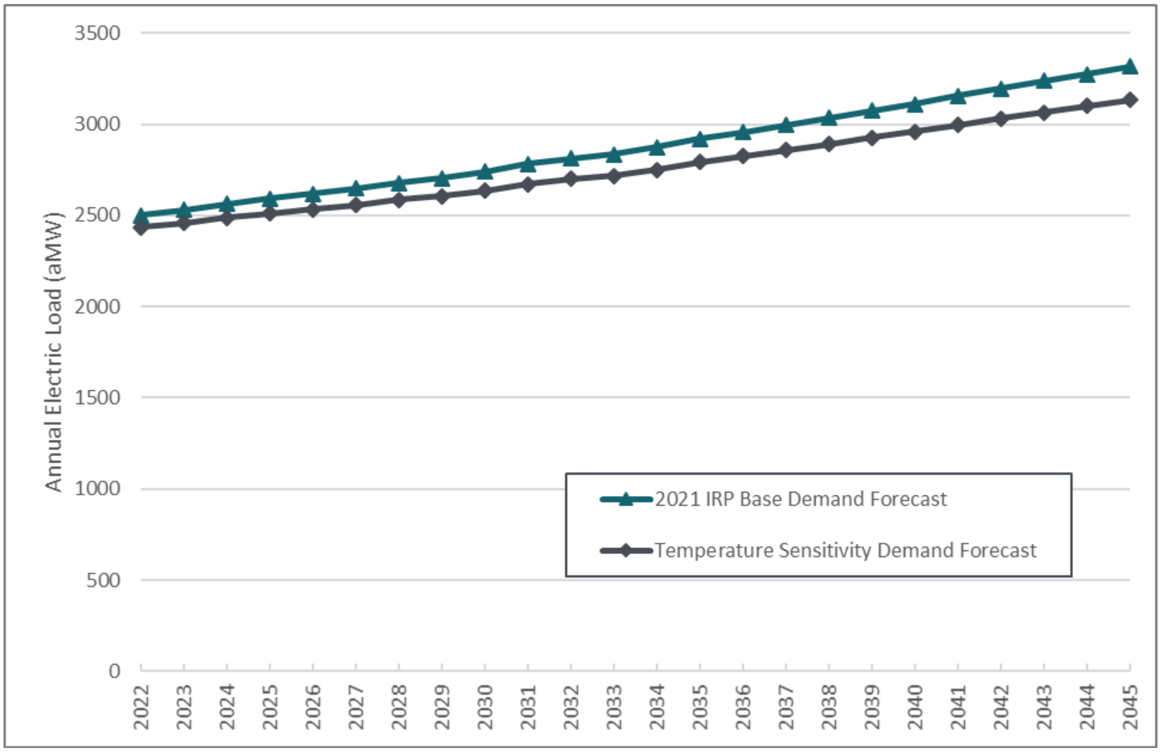
Baseline: The IRP Base Demand Forecast used in the Mid Scenario is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the past 30 years ending in 2019.

Sensitivity R > PSE used forecast temperature data from the Northwest Power and Conservation Council (the "Council") to model a new demand forecast. The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, the rate of temperature increase found in the Council's climate model. PSE also updated the peak capacity need using the resource adequacy analysis. A full description of the temperature sensitivity can be found in Chapter 7.

KEY FINDINGS. Using alternative temperature data for forecasting demand and peak changed the key modeling assumptions for the portfolio and produced a lower demand forecast, lower CETA renewable need and a lower peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity R selected lower resource builds and had lower portfolio costs compared to the Mid Scenario. Resource additions were driven by the CETA renewable need, and a total of 4,495 MW nameplate capacity of renewable resources was added by 2045 to meet CETA.

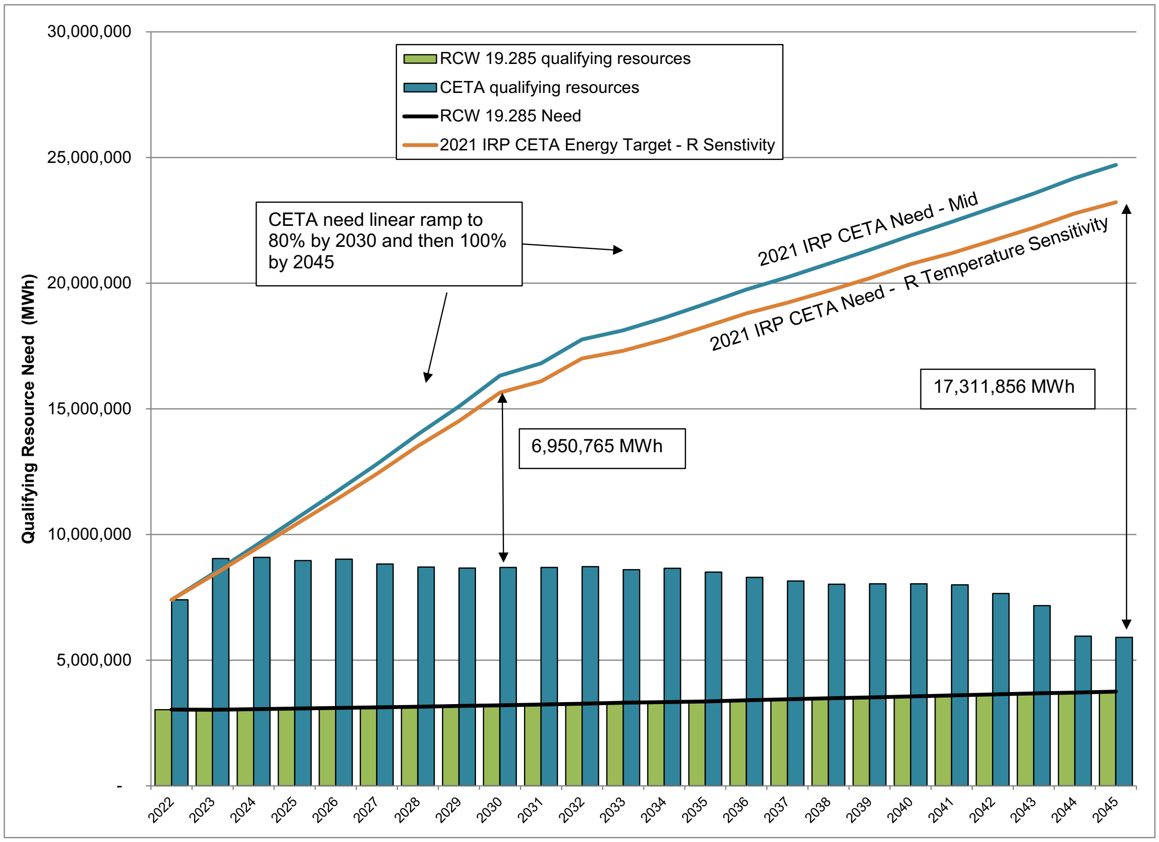
ASSUMPTIONS. In this sensitivity, the demand forecast reflects temperatures warming over time based on the trend of one model that the Council is using in its climate analyses. The related demand forecast is discussed in Chapter 6, Demand Forecasts. Figure 8-115 shows the annual electric load (aMW) used for Sensitivity R compared to the Mid Scenario.

Figure 8-115: Electric Energy Demand Forecast – Mid Scenario Compared to Temperature Sensitivity Demand Forecast (aMW)



The CETA renewable need is updated to reflect the change in the electric demand forecast. Figure 8-116 shows the CETA renewable need for Sensitivity R compared to the Mid Scenario. In Sensitivity R, the CETA renewable need in 2045 is 17.3 million MWhs, a decrease of 1.5 million MWhs from the Mid Scenario.

Figure 8-116: CETA Renewable Need – Mid Scenario and Sensitivity R



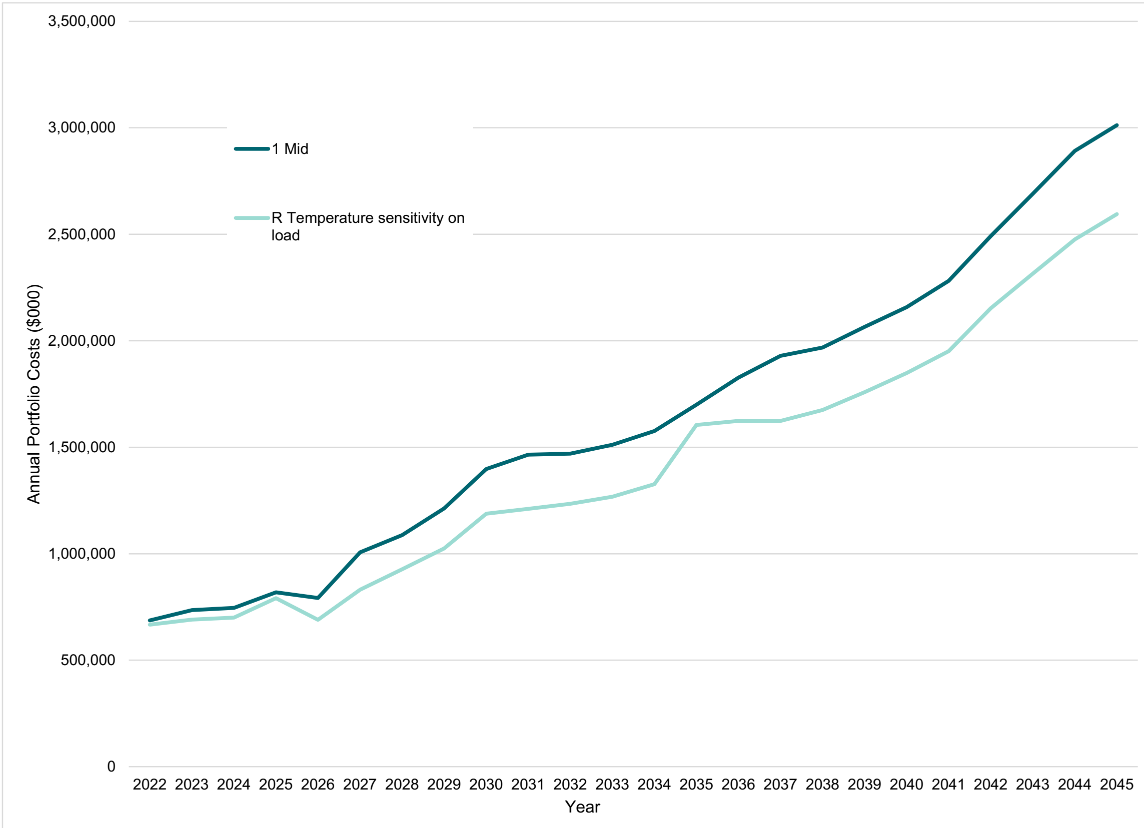
In addition to the change in the electric demand forecast and CETA renewable need, the Resource Adequacy Model was run for this temperature sensitivity reflecting a decrease in peak capacity need from 907 MW to 328 MW in 2027, and from 1,381 MW to 1,019 MW in 2031. More information on this sensitivity can be found in Chapter 7, Resource Adequacy Analysis.

ANNUAL PORTFOLIO COSTS. Figures 8-117 and 8-118 illustrate the breakdown of costs between the Mid Scenario and Sensitivity R. The reduction in costs for Sensitivity R is due to the decrease in the overall resource builds.

Figure 8-117: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity R

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
R	Temperature Sensitivity	$13.53	$4.69	$18.22	($2.40)

Figure 8-118: Annual Portfolio Costs – Mid Scenario and Sensitivity R



RESOURCE ADDITIONS. Figures 8-119 and 8-120 compare the nameplate capacity additions of the Sensitivity R and Mid Scenario portfolios. Peaking capacity resources are not added in Sensitivity R. All other resource options have lower additions except for 2-hour lithium-ion batteries and biomass, both of which showed a minor increase. Sensitivity R selected conservation Bundle 9, which includes 1,372 MW of capacity, whereas the Mid Scenario selected Bundle 10.

Figure 8-119: Portfolio Additions – Mid Scenario and Sensitivity R

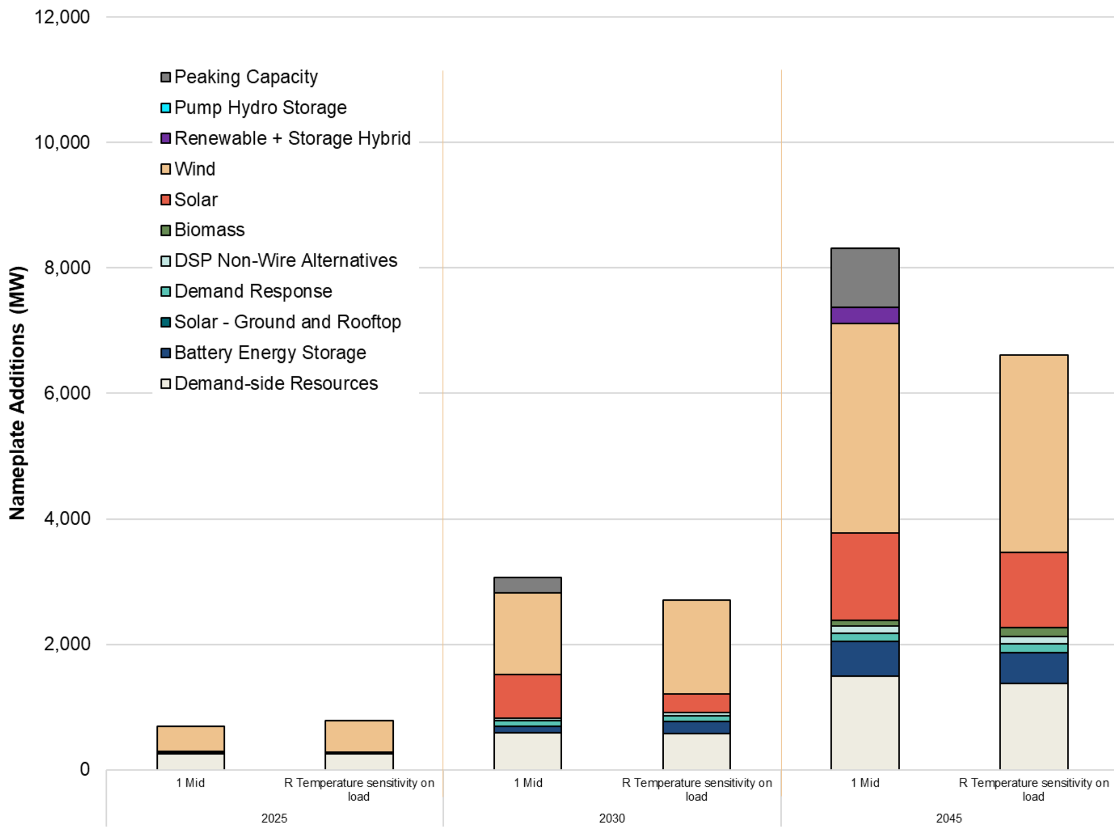
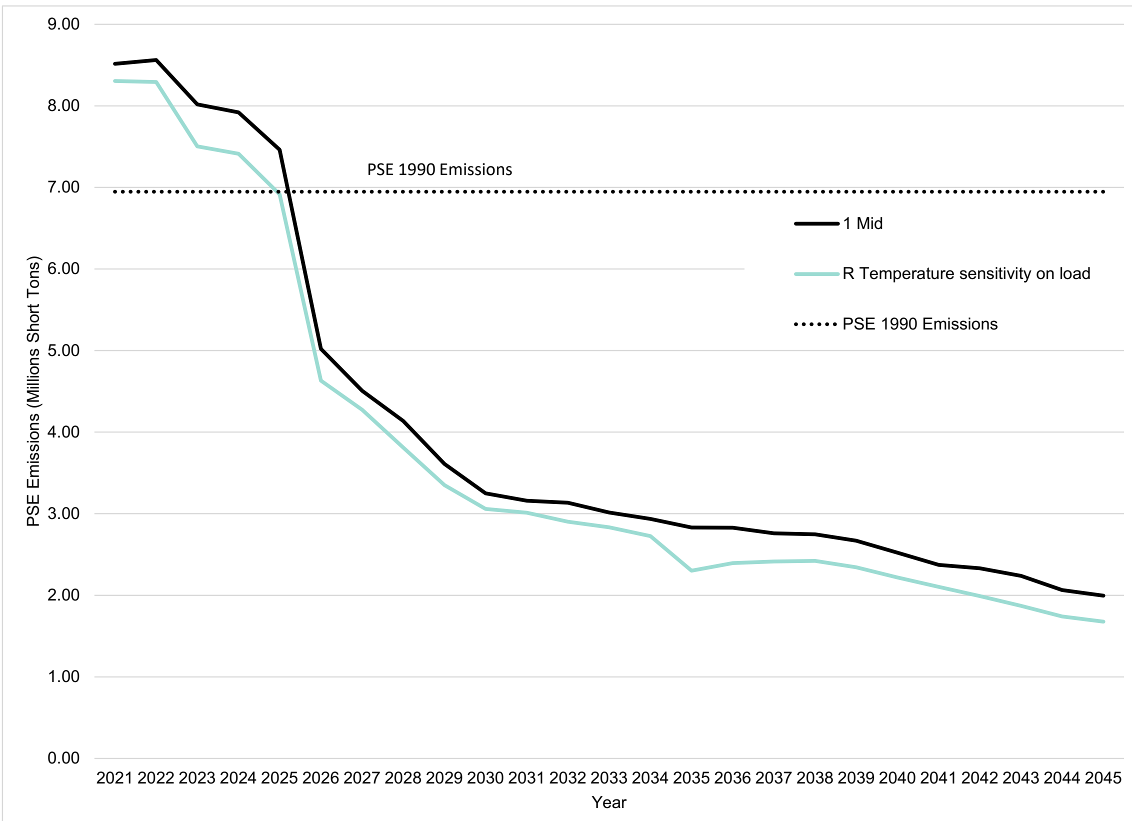


Figure 8-120: Portfolio Additions – Mid Scenario and Sensitivity R

Resource Additions by 2045	1 Mid	R Temperature sensitivity on load
Demand-side Resources	1,497 MW	1,372 MW
Battery Energy Storage	550 MW	500 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	130 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,495 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,195 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	0 MW

EMISSIONS AND ECONOMIC RETIREMENTS. Sensitivity R resulted in fewer GHG emissions compared to the Mid Scenario. This is due to the lower dispatch of existing thermal resources and the lack of peaking capacity resource additions. The lower energy demand and peak capacity need also contributed to the economic retirement of existing thermal plants. Two of the natural gas resources were retired by 2023 and replaced by 2-hour lithium-ion batteries. Figure 8-121 compares the GHG emissions from Sensitivity R with the Mid Scenario.

Figure 8-121: Annual Emissions – Mid Scenario and Portfolio R



CETA Costs

S. SCGHG Cost Included, No CETA
T. No CETA

The purpose of this sensitivity is to evaluate the cost of CETA compliance. To assess the effect of CETA and the SCGHG, a baseline must be established. Sensitivity S models PSE without the CETA renewable generation requirement. Sensitivity T models PSE without the CETA renewable requirement or the SCGHG. By analyzing the PSE portfolios without CETA requirements, the impact of CETA can be quantified.

Baseline: The Mid Scenario includes SCGHG for thermal resources as a fixed cost adder and CETA requirements.
Sensitivity S > The model includes SCGHG as a fixed cost adder, but there is no CETA renewable requirement.
Sensitivity T > The model includes no SCGHG and no CETA renewable requirement.

KEY FINDINGS. Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement for Sensitivity T is $9.05 billion dollars, $6.48 billion dollars less than the Mid Scenario portfolio. Compared to Sensitivity S, the 24-year levelized revenue requirement for Sensitivity T is higher by $0.02 billion dollars. The price differences between Sensitivity S and T are negligible, indicating that some conservation and demand response additions can be a revenue requirement-neutral way of cutting emissions. Even so, less conservation is selected in both sensitivities compared to the Mid Scenario.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.

In Sensitivity S, the SCGHG is included as a fixed cost adder for thermal resources during resource selection. The CETA renewable generation requirement is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

In Sensitivity T, there is no CETA renewable requirement and the SCGHG is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

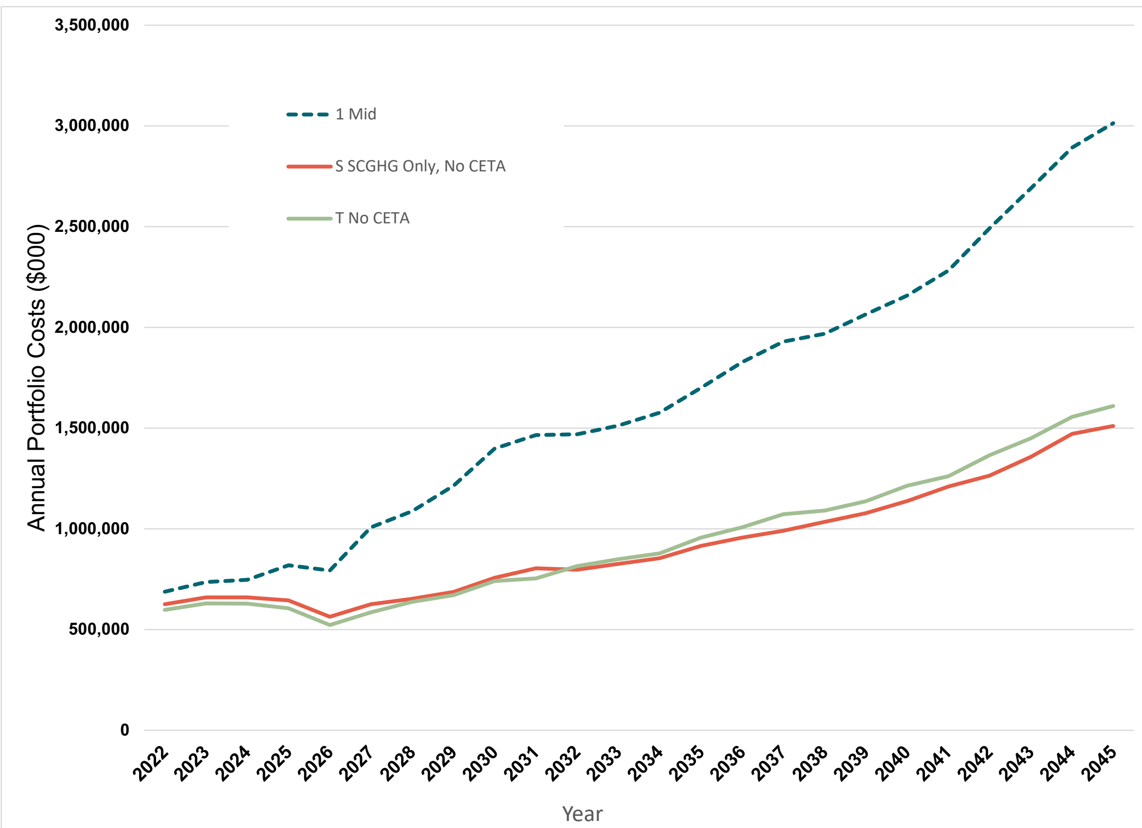
ANNUAL PORTFOLIO COSTS. Figures 8-122 and 8-123 illustrate the breakdown of costs between the Mid Scenario, Sensitivity S and Sensitivity T portfolios. The conservation resources selected in Sensitivity S drive the revenue requirements of the portfolio even lower compared to

Sensitivity T, as they slow the pace of peaker construction and prevent an additional frame peaker from being built by 2045. Since the SCGHG is not included in Sensitivity T, the costs of emissions are not included.

Figure 8-122: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
S	SCGHG Only, No CETA	$9.03	$8.86	$17.89	($2.73)
T	No CETA, No SCGHG	$9.05	--	$9.05	($11.57)

Figure 8-123: Annual Portfolio Costs – Mid Scenario, Sensitivities S and Sensitivity T



RESOURCE ADDITIONS. Figure 8-124 compares the nameplate capacity additions of the Mid Scenario to Sensitivities S and T. The build patterns of Sensitivities S and T are similar and simple; both portfolios build frame peakers to keep up with increasing demand. Aside from the Montana wind addition in 2044 to maintain compliance with the RPS requirement, no new renewable resources are built in either portfolio. In Sensitivity T, conservation Bundle 2 is selected, along with 3 demand response measures. In Sensitivity S, conservation Bundle 6 is selected, along with 11 demand response measures. Sensitivity S also builds 50 MW of 2-hour lithium-ion batteries in 2025. The additional demand response, conservation, and storage added in Sensitivity S results in one less frame peaker resource being built by 2045 compared to Sensitivity T.

Figure 8-124: Portfolio Additions – Mid Scenario, Sensitivity S and Sensitivity T

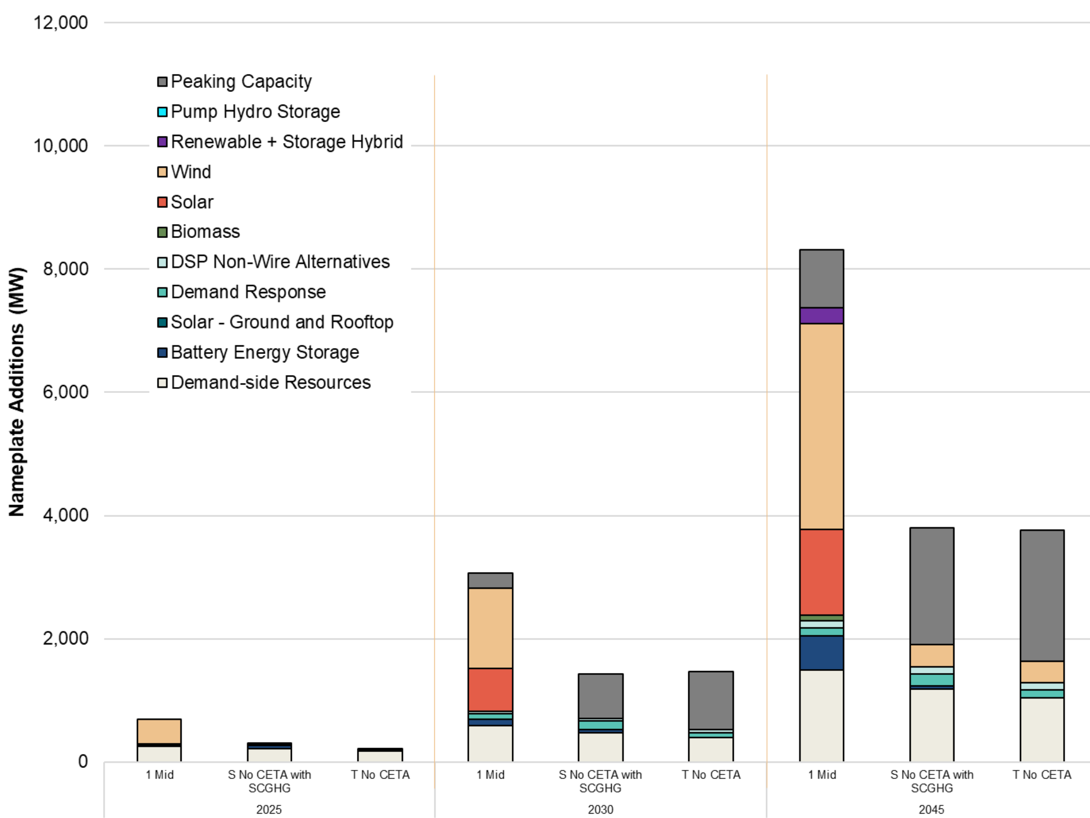
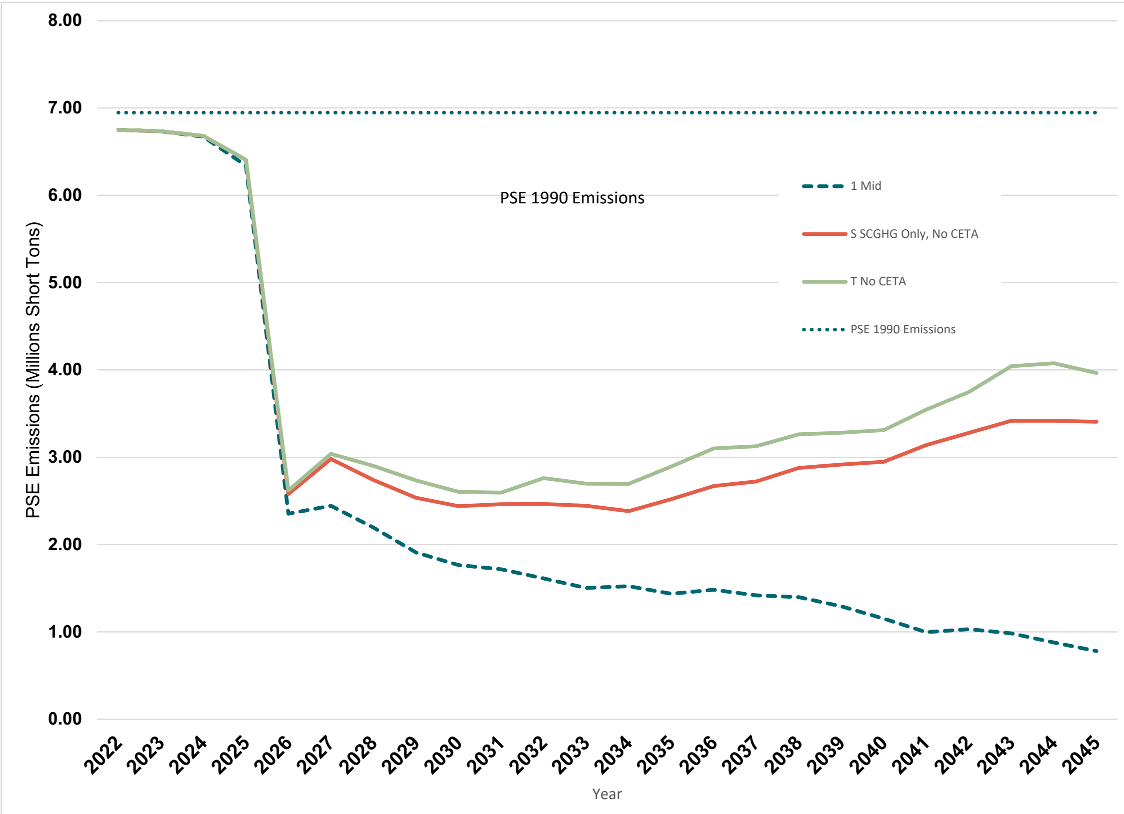


Figure 8-125: Portfolio Additions by 2045 – Mid Scenario, Sensitivity S and Sensitivity T

Resource Additions by 2045	1 Mid	S SCGHG Only, No CETA	T No CETA
Demand-side Resources	1,497 MW	1,179 MW	1,042 MW
Battery Energy Storage	550 MW	50 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	203 MW	123 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	350 MW	350 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	0 MW	0 MW
Wind	3,350 MW	350 MW	350 MW
Renewable + Storage Hybrid	250 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW	2,133 MW

EMISSIONS. As expected, the S and T portfolios have a significantly higher rate of emissions than the Mid Scenario. The ultimate goal of CETA is to reduce GHG emissions, and the S and T portfolios demonstrate the need for CETA in curbing emissions from PSE's portfolio. Figure 8-126 shows the annual emissions of the PSE portfolio in Sensitivities S and T.

Figure 8-126: Portfolio Emissions – Mid Scenario, Sensitivity S and Sensitivity T (market purchases are not included)



U. 2% Cost Cap Threshold

The incremental cost of compliance section of CETA states:

> An investor-owned utility must be considered to be in compliance with the standards under RCW 19.405.040(1) and 19.405.050(1) if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a <u>two percent</u> increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations above the previous year, as reported by the investor-owned utility in its most recent commission basis report.[6]

6 / RCW 19.405.060 3(a)

PSE calculated the incremental cost as the difference between Portfolio T, No CETA with SCGHG adder, and the preferred portfolio, Portfolio W. The calculation is as follows:

$$Incremental\ Cost = \ Preferred\ Portfolio\ Annual\ Cost - No\ CETA\ with\ SCGHG\ adder\ annual\ Cost$$

The 2 percent cost threshold is calculated based upon the expected annual revenue requirement. Figure 8-127 illustrates how the 2 percent cost threshold is calculated. First, the current revenue requirement is established using PSE's 2019 General Rate Case (GRC) revenue requirement. The GRC revenue requirement is adjusted for inflation at 2.5 percent per year to obtain the estimated 2021 revenue requirement (shown in the top half of the figure). The 2 percent cost threshold for the year 2022 is simply 2 percent of the inflation-adjusted GRC revenue requirement in 2021, approximately $44 million. For subsequent years, 2 percent of the inflation-adjusted GRC revenue requirement is added to the previous 2 percent cost threshold (also adjusted for inflation). This creates the compounding 2 percent cost threshold (shown in the bottom half of the figure).

Figure 8-127: Calculation of the 2 Percent Cost Threshold

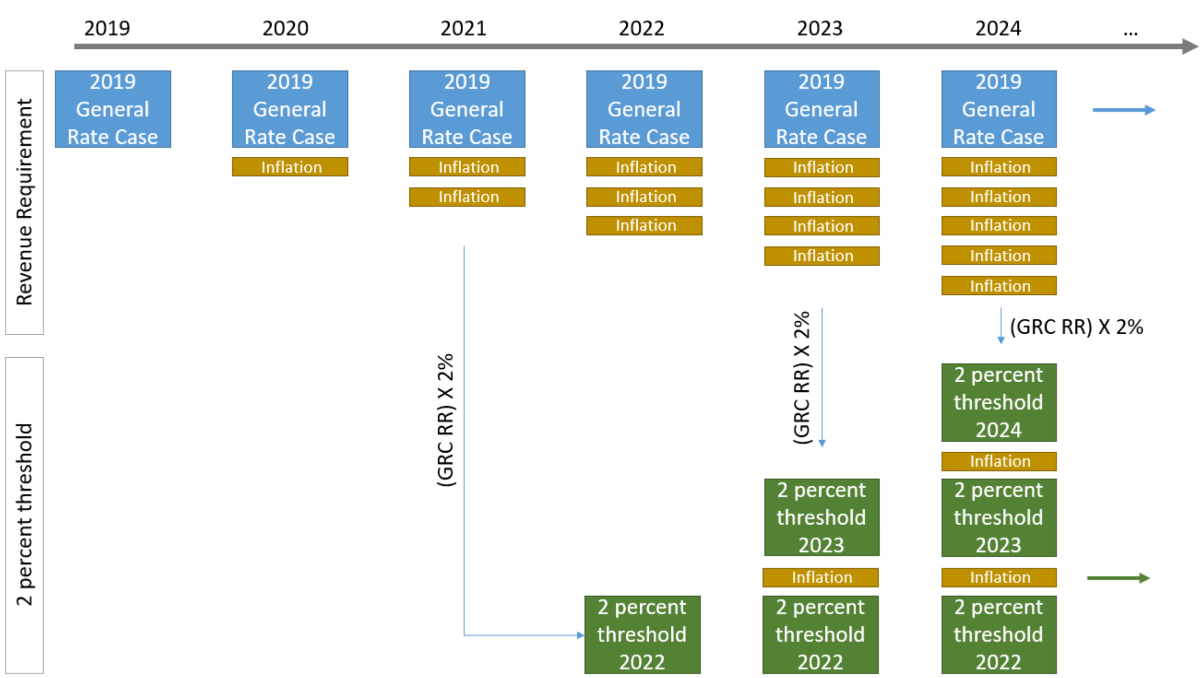
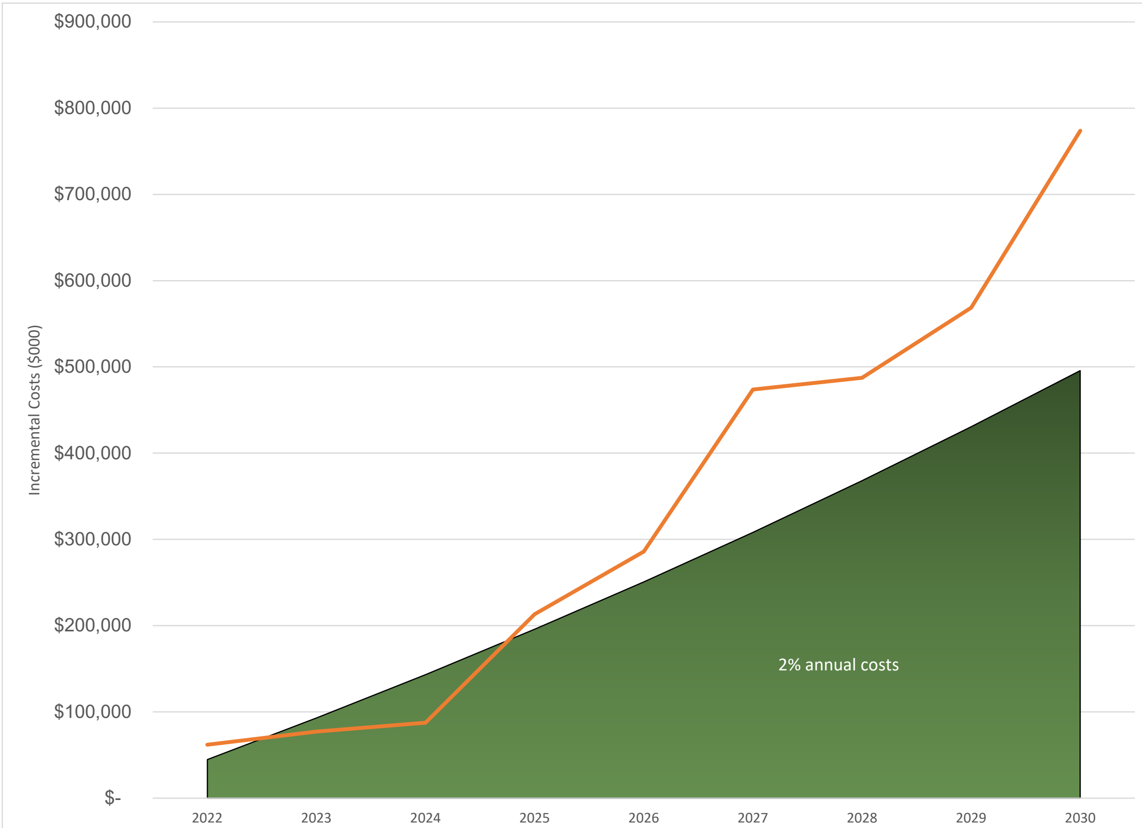


Figure 8-128 compares the 2 percent cost threshold (the green area) with the incremental cost of the preferred portfolio (the orange line). By 2025, the cost of CETA compliance increases to more than the 2 percent cost threshold.

Figure 8-128: Incremental Cost of CETA Compliance



There is some uncertainty associated with this comparison. The annual portfolio costs only include the costs associated with generating resources modeled in the IRP. There may be other costs that are not captured as part of the IRP analysis. Better clarity into this comparison will be obtained through the CEIP. All costs associated with the CETA implementation will be available and included in CEIP. In this IRP, PSE has included the cost of compliance calculation and a comparison with the preferred portfolio for information only.

Balanced Portfolios

V. Balanced Portfolio

Sensitivity V applies insights gained from the analysis of other sensitivities to compare with the results to the Mid Scenario portfolio. Sensitivity V gives increased consideration to distributed energy resources, ramping those and other customer programs in over time starting in 2025. In contrast, the Mid Scenario capacity expansion model is set to optimize total portfolio cost and builds new resources toward the end of the planning period because the cost curve of all resources declines over time. In Sensitivity C, for example, the model waits until the end of the planning period to add a significant amount of distributed resources. However, waiting until the end is not always realistic.

Baseline: New resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity V1 > Increased distributed energy resources and customer programs are ramped in over time. These include rooftop and ground-mounted solar, demand response programs, battery energy storage, customer-owned rooftop solar and an expanded Green Direct program.
Sensitivity V2 > Same as Sensitivity V1, with the substitution of a Montana wind + pumped hydro storage resource for the first eastern Montana resource constructed in 2028, similar to Sensitivity AA described below.
Sensitivity V3 > Same as Sensitivity V1, except conservation measures ramp in over 6 years instead of 10 years, similar to Sensitivity F described above.

KEY FINDINGS. Ramping in resource additions versus economic resource selection resulted in higher portfolio costs in Sensitivity V variations compared to the Mid Scenario. Distributed solar resources are higher cost than Washington wind and Washington solar east resources, which were found to be the optimal renewable resources after the addition of Montana and Wyoming wind resources in the Mid Scenario portfolio. In Sensitivity V1, the 24-year levelized revenue requirement is $16.06 billion, an increase of $0.47 billion or 3 percent over the Mid Scenario portfolio. Adding MT wind plus pumped hydro storage (V2) or a 6-year DSR ramp increases these costs further.

ASSUMPTIONS. Sensitivity V1 assumes greater investment in distributed energy resources and load-reducing resources like the Green Direct program and conservation measures to create a portfolio with greater balance between large, central power plants and small, distributed resources. Investments in these resources are modeled as must-take resource additions. These must-take resource additions include:

- Addition of 50 MW of distributed, ground-mounted solar in the year 2025.
- Annual addition of 30 MW of distributed, rooftop solar from the year 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Addition of all demand response programs with a cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from the year 2025 to 2031 for a total of 175 MW of nameplate capacity.
- An adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.
- Addition of three new Green Direct programs consisting of 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

PSE has ramped in resource additions in this sensitivity to spread out the acquisition of new resources. All generic resource options are still available for economic selection by the optimization model.

Sensitivity V2 makes the same assumptions as Sensitivity V1 except a Montana wind + pumped hydro storage resource is forced into the portfolio in the year 2028.

Sensitivity V3 makes the same assumptions as Sensitivity V1 except conservation measures are implemented over 6 years instead of 10 years and associated costs and energy savings are updated.

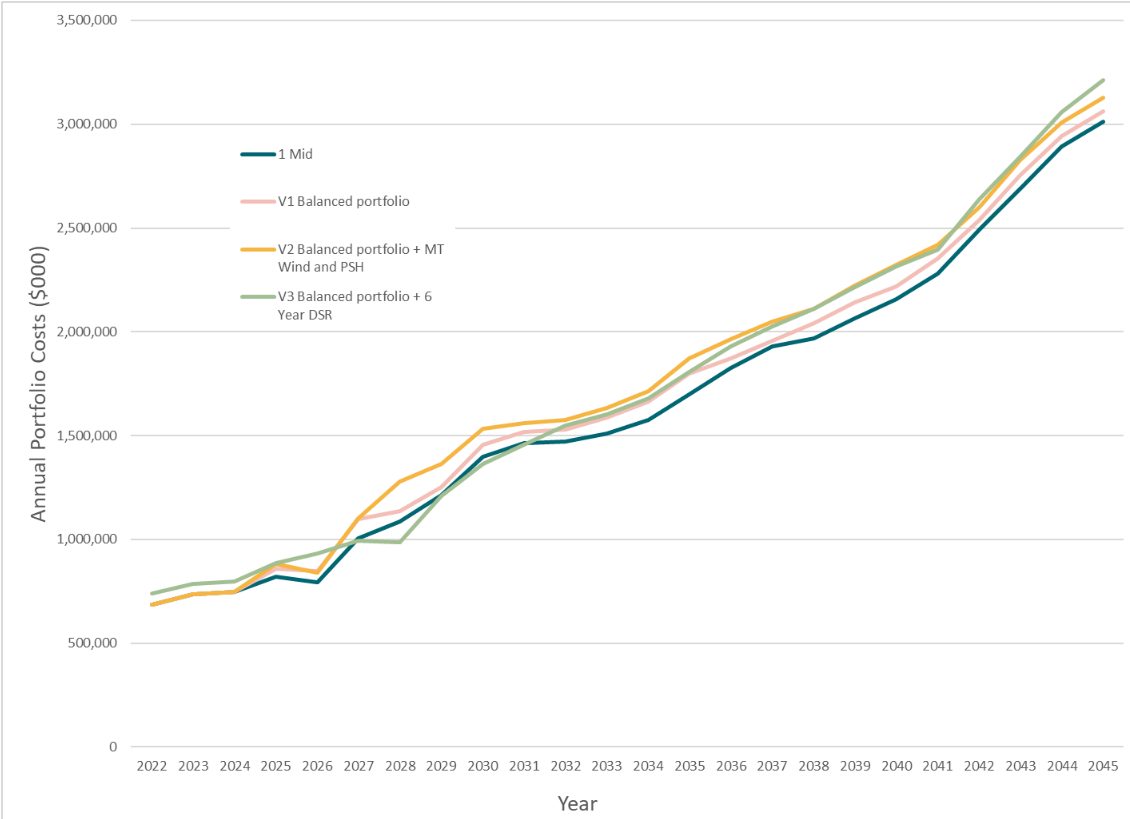
PORTFOLIO COSTS. Figures 8-129 and 8-130 compare the portfolio costs and annual revenue requirements, respectively, of the Sensitivity V variations and the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in overall higher portfolio costs for the Sensitivity V variations compared to the Mid Scenario. Sensitivity V1 has a slightly higher revenue requirement from 2024 to the end of the planning period compared to the Mid Scenario. Sensitivity V2 has a significant increase the annual revenue requirement in 2028 from the addition of the expensive Montana wind plus pumped hydro storage resource and never recovers those costs compared to the Mid Scenario. Sensitivity V3 starts as the most expensive portfolio due to the accelerated ramp of conservation measures, and then sees some cost savings in the years 2027 to 2032 compared to the Mid Scenario. However, in 2032 the Mid Scenario conservation measures complete their 10-year ramp-in, equalizing the energy savings between the two portfolios. After 2032, Sensitivity V3 costs increase above the Mid Scenario due to resource acquisitions in the later portion of the planning period.

The SCGHG for the Sensitivity V variations is similar the SCGHG for the Mid Scenario. Sensitivities V1 and V2 achieve slightly lower SCGHG than the Mid Scenario, while Sensitivity V2 has a slightly higher SCGHG overall.

Figure 8-129: Portfolio Cost Comparison – Mid Scenario and Sensitivities V, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
V1	Balanced Portfolio	$16.06	$5.07	$21.14	$0.54
V2	Balanced Portfolio with MT wind + PHES	$16.61	$5.12	$21.73	$1.11
V3	Balanced Portfolio with 6-year DSR	$16.26	$5.06	$21.32	$0.70

Figure 8-130: Annual Portfolio Costs – Mid Scenario and Sensitivities V1, V2 and V3



RESOURCE ADDITIONS. Figures 8-131 and 8-132 compare the nameplate capacity additions of the Sensitivity V variations and the Mid Scenario portfolio. Resource additions for Sensitivity V1 and the Mid Scenario are similar, except for the quantity of ground-mounted and rooftop solar forced into the portfolio in the early years that displaces utility-scale solar. Resource additions for the Sensitivity V variations are all very similar. Sensitivity V3 delays acquisition of resources until the later years of the planning period, but concludes the planning period with a similar resource mix as Sensitivities V1 and V2.

Figure 8-131: Portfolio Additions – Mid Scenario and Sensitivities V1, V2 and V3

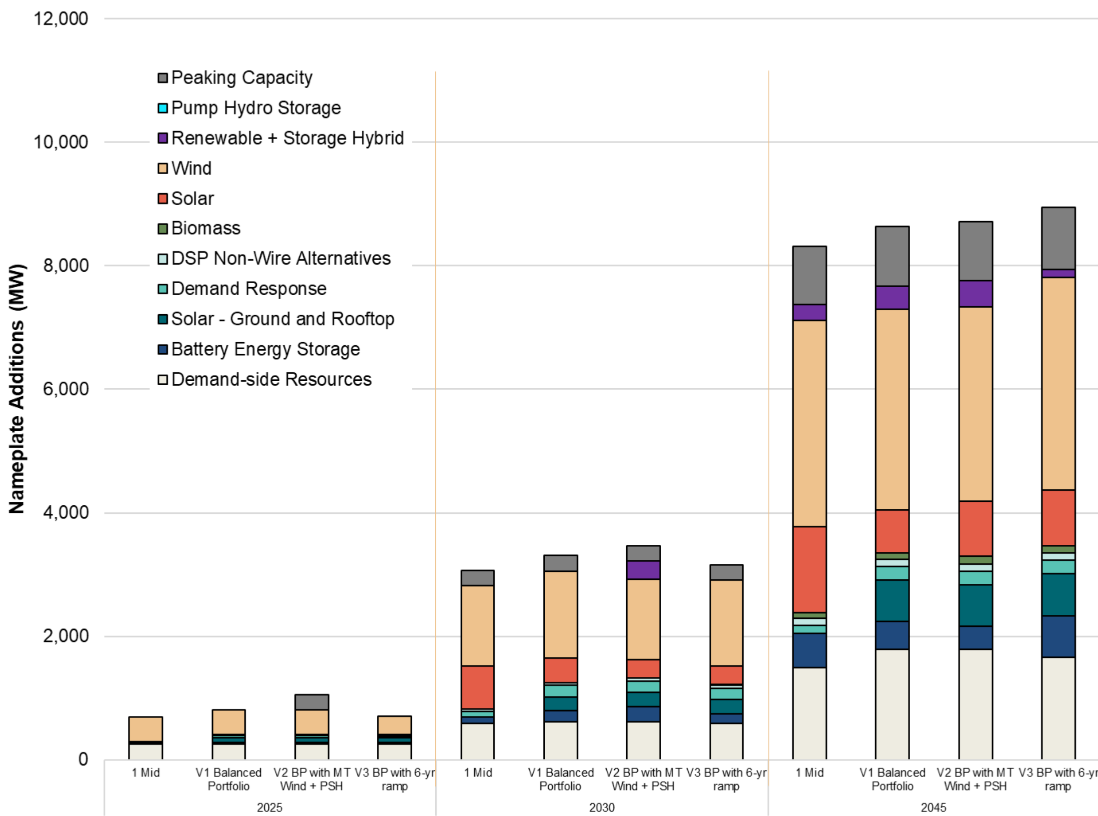
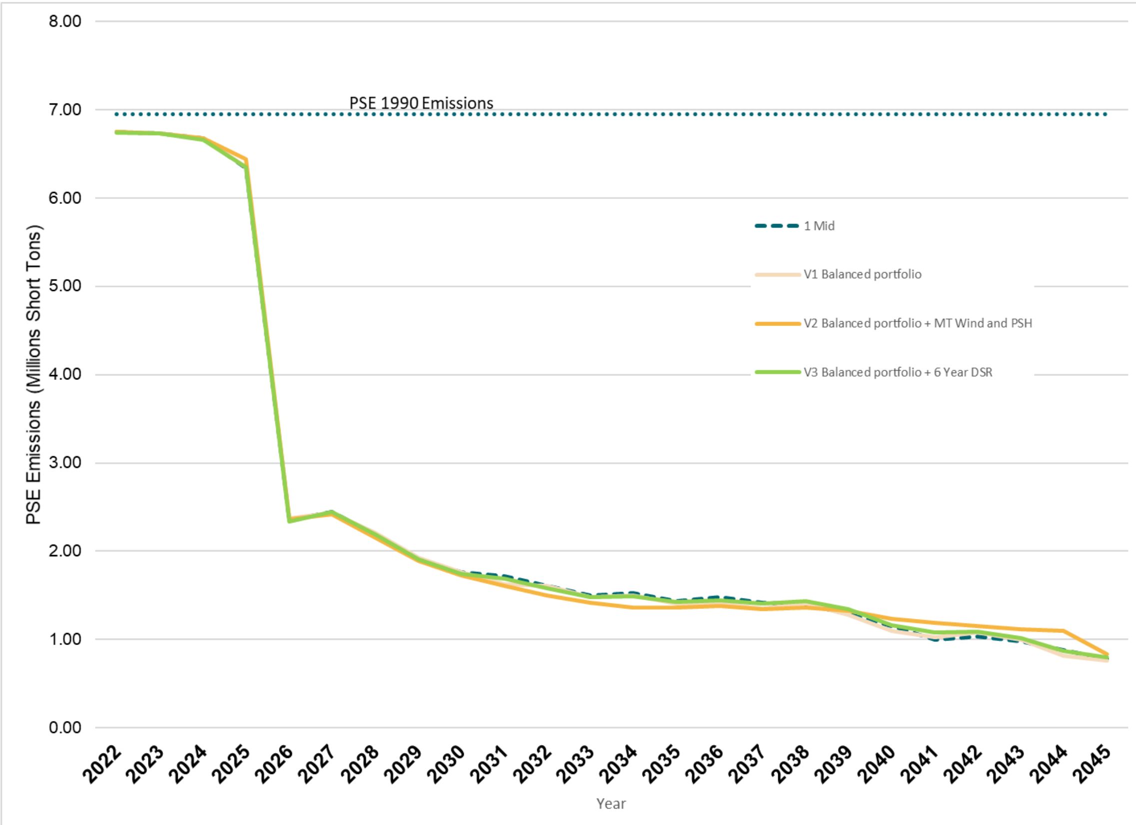


Figure 8-132: Portfolio Additions by 2045 – Sensitivities V1, V2 and V3

Resource Additions by 2045	Mid Scenario Portfolio	Sensitivity V1 - Balanced Portfolio	Balanced Portfolio with MT wind + PHES	Balanced Portfolio with 6-year DSR
Demand-side Resources	1,497 MW	1,784 MW	1,784 MW	1,658 MW
Battery Energy Storage	550 MW	450 MW	375 MW	675 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,051 MW	4,165 MW	4,465 MW
Biomass	90 MW	105 MW	120 MW	120 MW
Solar	1,393 MW	696 MW	895 MW	895 MW
Wind	3,350 MW	3,250 MW	3,150 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	375 MW	425 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	948 MW	1,003 MW

OTHER FINDINGS: GHG Emissions. Figure 8-133 compares the direct GHG emissions from Sensitivities V1, V2 and V3 with the Mid Scenario. Significant emissions reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. All three Sensitivity V variations show similar reductions in emissions by the year 2045.

Figure 8-133: Portfolio GHG Emissions – Sensitivities V1, V2 and V3

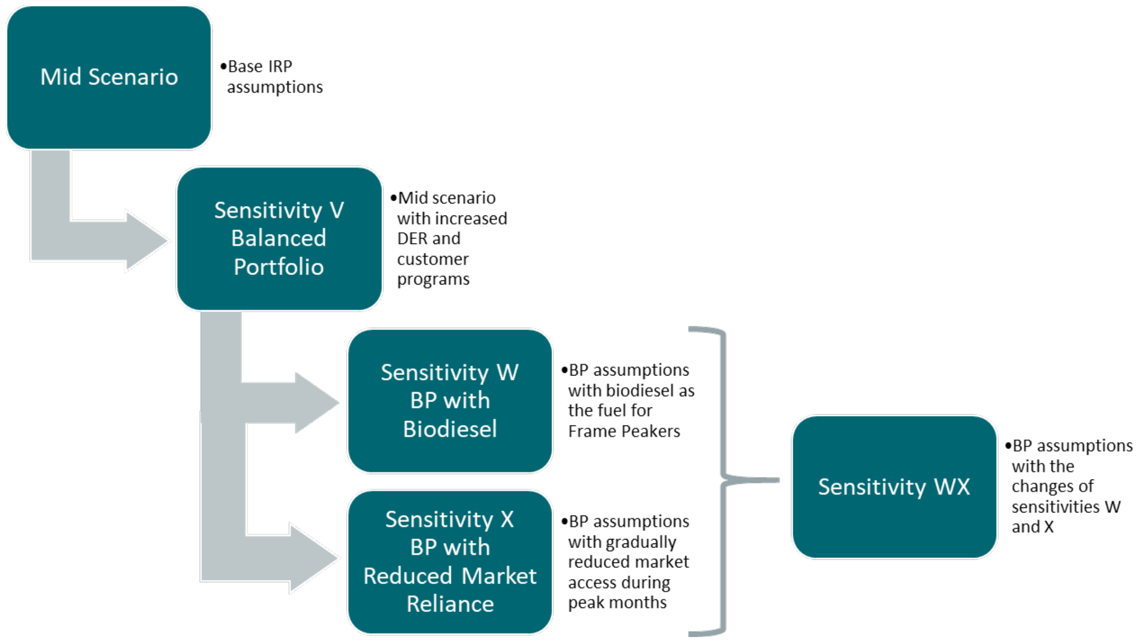


W. Balanced Portfolio with Alternative Fuel
X. Balanced Portfolio with Reduced Market Reliance
WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivities W and X incorporate significant changes to Sensitivity V1, the Balanced Portfolio. Sensitivity W substitutes biodiesel for natural gas in new peaking capacity resources and Sensitivity X reduces the market reliance of the portfolio. Sensitivity WX applies the key changes in Sensitivities W and X simultaneously. Figure 8-134 illustrates how these changes are applied.

Figure 8-134: Sensitivities V, W, X and WX, and Their Relation to the Mid Scenario

BP = Balanced Portfolio



Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.

Sensitivity W > Same as Sensitivity V1, with the addition of biodiesel as the fuel source for new frame peaker resources, similar to Sensitivity M.

Sensitivity X > Same as Sensitivity V1, but market purchases during seasonal peak conditions gradually decline by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August), similar to sensitivity B.

Sensitivity WX > Additional DER and customer programs are added to the portfolio. Biodiesel is used as a fuel for newly built frame peaker resources. The portfolio has reduced access to market purchases during peak demand months.

KEY FINDINGS: SENSITIVITY W. Extending the assumptions from Sensitivity V1 to include biodiesel as a fuel source for new frame peakers resulted in an increase of $0.57 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $16.10 billion, an increase of less than $0.04 billion from Sensitivity V1. Even with the premium on biodiesel fuel prices compared to natural gas prices, the model selected the same amount of frame peaker resources in Sensitivity W compared to the Mid Scenario portfolio.

KEY FINDINGS: SENSITIVITY X. While ramping in distributed energy resources and customer programs over time helps to achieve increased renewable resources, introducing the reduced market reliance strategy creates tension, since Sensitivity X adds more peaking capacity resources compared to the Mid Scenario and Sensitivity V. The 24-year levelized revenue requirement for Sensitivity X is $17.21 billion, $1.68 billion more than the Mid Scenario and $1.14 billion more than Sensitivity V1.

KEY FINDINGS: SENSTIVITY WX. Portfolio WX is nearly identical to portfolio X. The same resources are selected at the same time. The only difference in builds is an increase in demand-side resources. Portfolio WX emissions decrease compared to portfolio X due to the use of biodiesel, but are higher than portfolio W due to the reduced availability of market purchases during peak hours.

ASSUMPTIONS: Sensitivity V1: Balanced Portfolio
Increased distributed energy resources and customer programs ramp in over time as follows:

- Addition of 50 MW of distributed, ground-mounted solar in 2025.
- Annual addition of 30 MW of distributed, rooftop solar from 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Annual addition of all demand response programs that cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from 2025 to 2031 for a total of 175 MW of nameplate capacity.
- Adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. (The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.)
- Addition of three new Green Direct programs: 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

ASSUMPTIONS: Sensitivity W. Sensitivity W uses the Sensitivity V1 assumptions, but also includes the use of alternative fuel for some peaking capacity resources. New frame peakers are assumed to be fueled by biodiesel instead of natural gas. Existing thermal resources, new CCCT+DF and new recip peakers continue to be fueled with natural gas throughout the modeling horizon. PSE estimated a biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020$, adjusted for inflation annually) informed by the U.S. Department of Energy's October 2020 Clean Cities Alternative Fuel Price Report.

ASSUMPTIONS: Sensitivity X. For Sensitivity X, available market purchases were constrained to capture the impact of reduced market reliance on the Balanced Portfolio. Available market purchases during peak conditions are reduced by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August).

Figure 8-135 shows the Sensitivity X market purchase limits for each year and month.

Figure 8-135: Monthly Market Purchase Access in Portfolio X (MW)

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

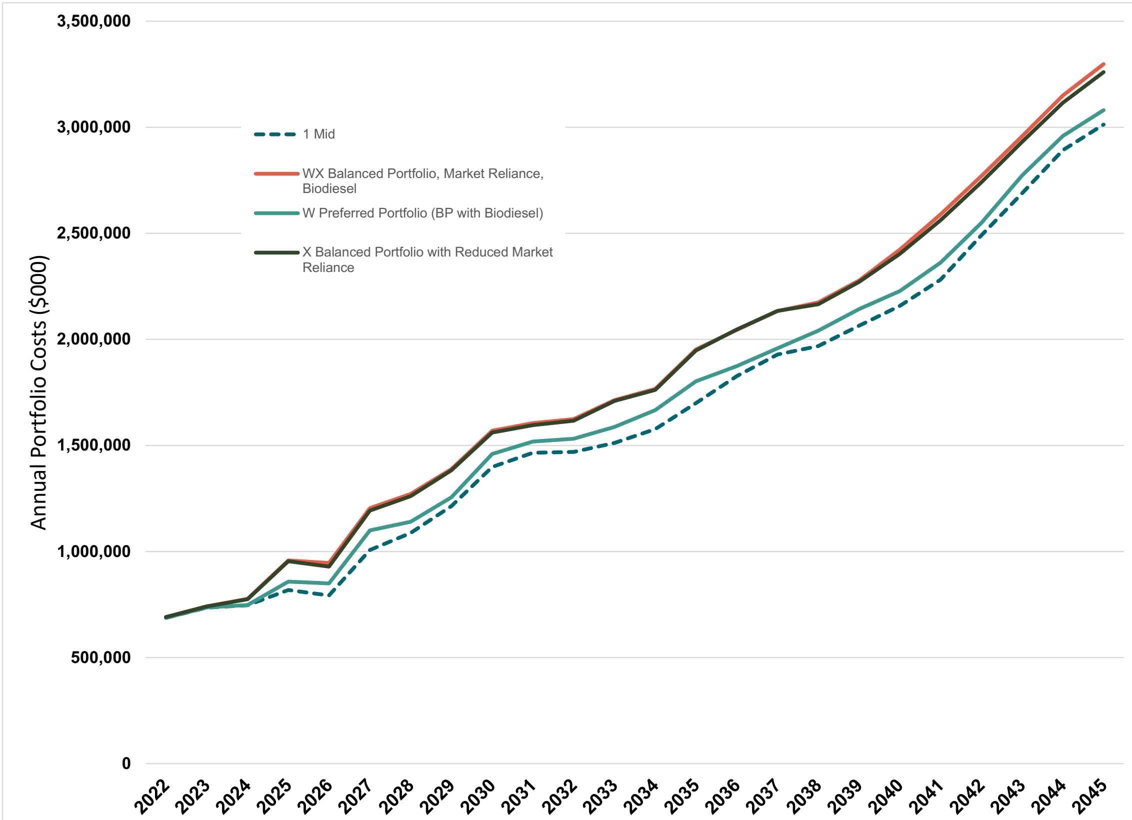
ASSUMPTIONS: Sensitivity WX. Sensitivity WX combines the changes incorporated to Sensitivity W and Sensitivity X. Therefore, biodiesel is available for new frame peakers and the portfolio has reduced market purchase limits.

ANNUAL PORTFOLIO COSTS. Figures 8-136 and 8-137 show the portfolio costs and annual revenue requirements, respectively, of Sensitivities WX, W and X, compared to the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in higher portfolio costs for Sensitivities WX, W and X. For Sensitivity W, increased portfolio costs are driven by the increased revenue requirements of the portfolio, as shown in Figure 8-X. Sensitivity W has slightly lower SCGHG due the use of alternative fuel for new peaking resources than the Mid Scenario portfolio. In Sensitivity X, the increased portfolio costs are due to the addition of more flexible capacity resources, which also increases the SCGHG. Portfolio WX significantly increases the revenue requirement over the Mid Scenario portfolio, although less than the combined increases of the W and X portfolios over the Mid Scenario. The portfolio builds are nearly identical to portfolio X, but the use of biodiesel reduces the SCGHG costs and costs overall. The slight increase in portfolio costs compared to portfolio X is due to the use of biodiesel and increased investment in demand-side resources.

Figure 8-136: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities WX, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
WX	Balanced Portfolio, Biodiesel, Reduced Market Reliance	$17.30	$5.06	$22.36	$1.74
W	Balanced Portfolio, Biodiesel	$16.10	$4.96	$21.06	$0.44
X	Balanced Portfolio, Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95

Figure 8-137: Annual Portfolio Costs – Mid Scenario and Sensitivities WX, W and X



RESOURCE ADDITIONS. Figures 8-138 and 8-139 compare the nameplate capacity additions of Sensitivities W, X, WX and the Mid Scenario portfolios.

Portfolio builds for Sensitivity W are relatively similar to the wind and peaking capacity resource builds in the Mid Scenario. Wind is a low cost, CETA-eligible resource, so it is to be expected that all four portfolios selected similar amounts of wind capacity. Peaking capacity resources are among the lowest cost methods to meet peak demand hours. Therefore, it is also to be expected that most portfolios will include some peaking capacity. Sensitivity W has an additional 18 MW of reciprocating peaker resources compared to the quantity of peaking capacity resources in the Mid Scenario. In Sensitivity W, new frame peaker resources are fueled with renewable biodiesel instead of natural gas which therefore does not include an SCGHG cost. However, biodiesel is also much more expensive than natural gas. At the current cost projections for biodiesel, it appears that the higher fuel price and lower SCGHG cost are offsetting each other, resulting in similar peaking resource decisions.

The primary differences between the Mid Scenario and Sensitivity W are related to the forced build decisions described in the assumptions section above. Increased distributed solar builds result in less utility-scale solar builds, as these resources fill a similar niche within the portfolio. Increased demand response programs in Sensitivity W may also offset some utility-scale solar builds.

More storage is built in Sensitivity W compared to the Mid Scenario portfolio. Sensitivity W ramps in 2-hour lithium-ion battery storage from 2025 to 2031. This storage is useful, particularly paired with the increased distributed solar builds in both sensitivities. However, the storage in the Mid Scenario portfolio is comprised of 4-hour lithium-ion and 6-hour flow battery storage, which is built after year 2040. Sensitivity W shows similar late year additions of longer duration storage, despite the abundance of 2-hour storage added early in the modeling horizon. This shows that longer-duration storage is an important component of these portfolios.

With the reduced market purchase limit in Sensitivity X, more conservation resources, battery energy storage and peaking capacity resources are added to fill the energy that would have been purchased in the market.

The builds of portfolio WX are nearly identical to portfolio X, the only difference is an increase in demand-side resources. The construction timeline of resources is also the same in WX and X.

Figure 8-138: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

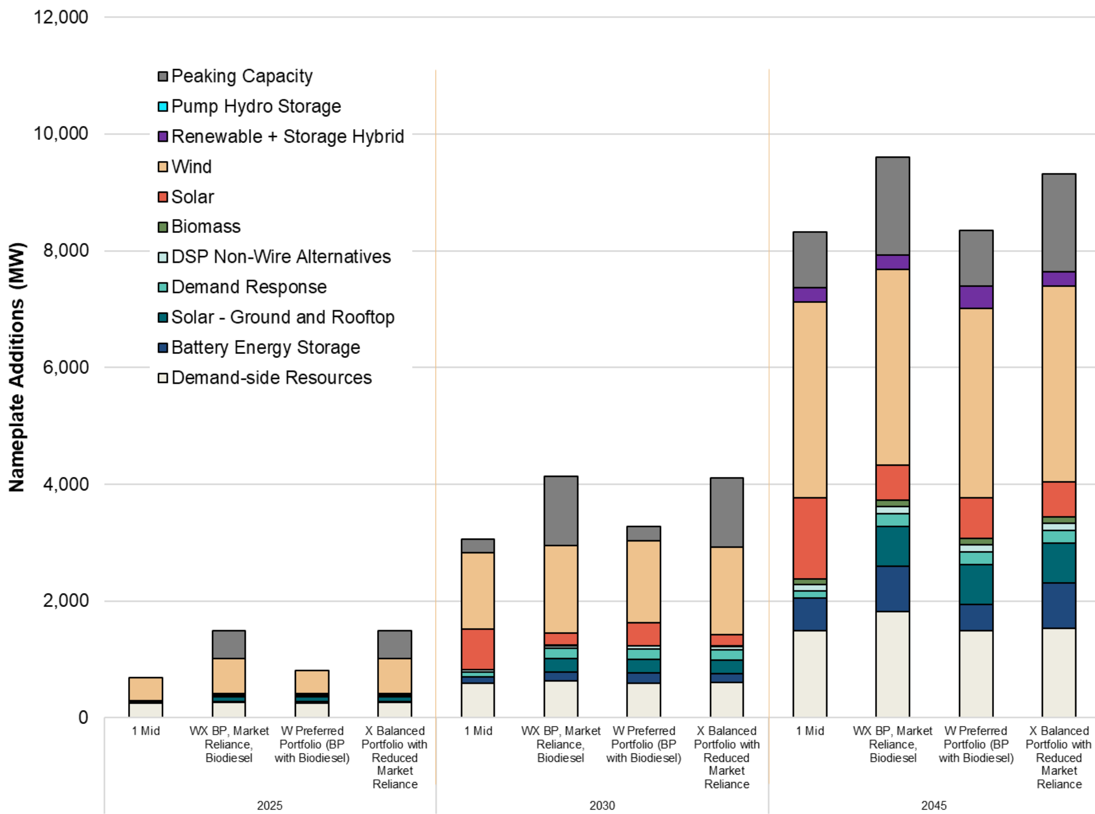
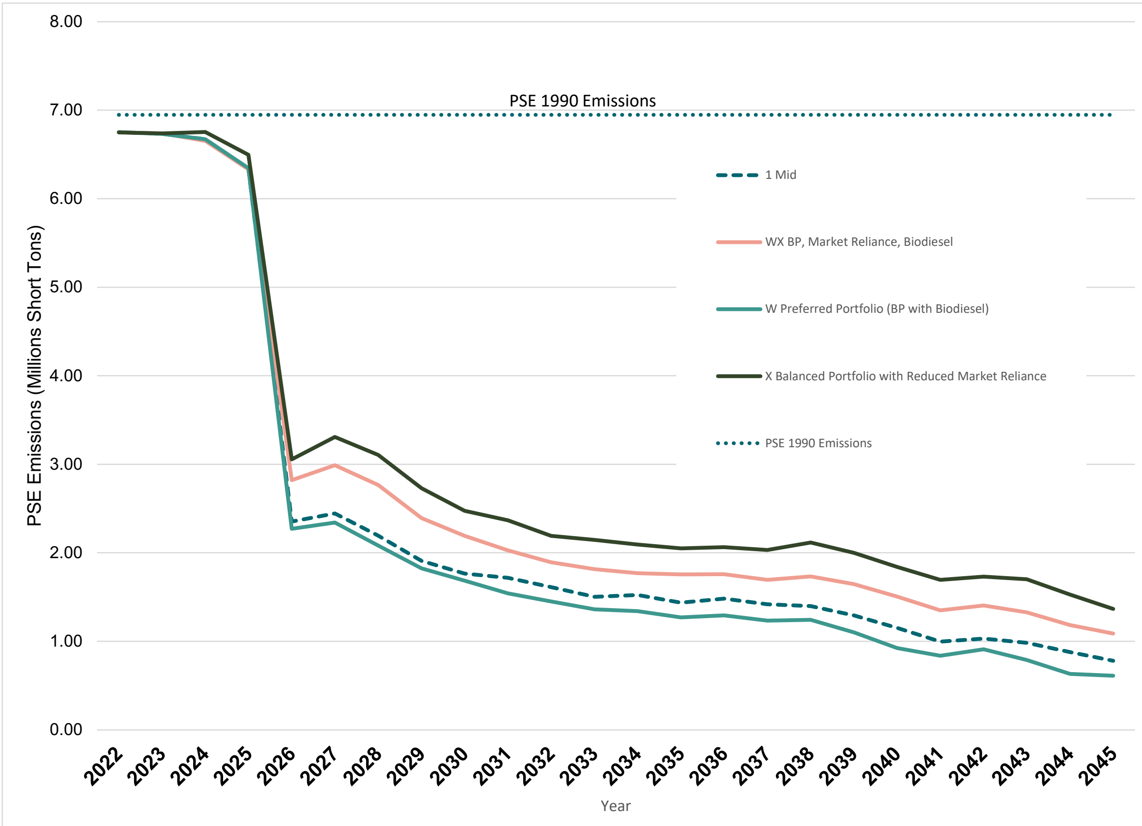


Figure 8-139: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

Resource Additions by 2045	1 Mid	WX BP, Market Reliance, Biodiesel	W Preferred Portfolio (BP with Biodiesel)	X Balanced Portfolio with Reduced Market Reliance
Demand-side Resources	1,497 MW	1,824 MW	1,784 MW	1,824 MW
Battery Energy Storage	550 MW	775 MW	450 MW	775 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,066 MW	4,051 MW	4,066 MW
Biomass	90 MW	120 MW	105 MW	120 MW
Solar	1,393 MW	596 MW	696 MW	596 MW
Wind	3,350 MW	3,350 MW	3,250 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	250 MW	375 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Flexible Capacity	948 MW	1,677 MW	966 MW	1,677 MW

EMISSIONS. Figure 8-140 compares direct GHG emissions from Sensitivities WX, W and X to the Mid Scenario. For Sensitivity W, emissions decrease compared to the Mid Scenario, through use of biodiesel for peaking capacity resources. For Sensitivity X, emissions increase compared to the Mid Scenario due to increased additions of peaking capacity resources. Consistent with the findings of sensitivities W and X, reducing market purchases and using of biodiesel have opposite effects on overall portfolio emissions. The overall emissions of portfolio WX fall between W and X.

Figure 8-140: Portfolio GHG Emissions – Mid Scenario and Sensitivity WX, W and X



Y. Maximum Customer Benefit

Maximizing customer benefits is a complex task. Numerous customer benefit indicators exist, and often increasing the benefit of one indicator reduces the benefit of another. Therefore, PSE's approach to maximizing customer benefits was to model a wide range of possible portfolios, many of which maximized specific customer benefit indictors. Through isolating and maximizing specific customer benefit indicators, it is possible to see trade-offs in other customer benefits and opportunities to balance those tradeoffs.

The following list highlights portfolios that maximize specific customer benefit indicators:

- Mid Scenario – The Mid Scenario, in addition to providing a basis for comparison to other sensitivities, is designed to be among the lowest cost portfolios. Over the 24-year timeframe, the Mid Scenario is ranked fourth best in terms of portfolio cost. Sensitivities G, I and M rank higher, but have only marginally lower portfolio costs and all include unique inputs which bring their costs down. Portfolio cost is directly related to the energy costs passed on to customers and should be minimized to keep energy burdens low. The AURORA portfolio model is an economic model which seeks to minimize cost; therefore, increasing other customer benefit indicators typically results in increased portfolio costs. In developing a preferred portfolio, PSE must balance portfolio cost with other customer benefit indicators.

- Sensitivity C – The distributed, transmission limited sensitivity maximizes utilization of distributed energy resources. Distributed energy resources provide significant transmission and distribution benefits, offsetting the need for long-distance transmission. In Sensitivity, C thermal resources were necessary to provide capacity during periods of peak demand resulting in higher emissions than most other portfolios. Distributed resources are also expensive compared to utility-scale resources, resulting in higher portfolio costs, but they offset potential transmission risk. Adding more distributed resources helps to optimize the customer benefit areas of environment and resiliency.
- Sensitivity N, the 100 percent renewable by 2030 sensitivity maximizes several customer benefit indicators through transitioning to a clean energy portfolio ahead of CETA targets. Sensitivity N2 (pumped hydro storage) obtains the highest rank for the 24-year timeframe for the customer benefit areas of Climate Change, Air Quality and Market Position. Sensitivity N1 (batteries) ties for the highest rank in Air Quality and achieves the highest rank in Resiliency. Sensitivity N1 uses batteries to provide capacity resulting in a much more resilient portfolio than Sensitivity N2, which relies on centralized pumped hydro storage for capacity. Early adoption of clean energy technologies carries significant benefits. However, these benefits are balanced by extremely high portfolio costs. Furthermore, both Sensitivities N1 and N2 score low in the Resource Adequacy customer benefit indicator area due to the reliance on short-term energy storage for capacity. These short-term energy storage resources are energy limited, exposing PSE's customers to risk in the event of long-duration peak events.

Other portfolios assessed in this IRP provide varying degrees of customer benefits. Results for these portfolios are available earlier in this chapter. Of particular importance, are the Balanced Portfolios (Sensitivities V, W and WX) which do not seek to maximize any single customer benefit, but to provide meaningful contributions to customer benefit indicators to develop a well-rounded, low-risk portfolio.

Z. No DSR

This sensitivity examines the value of conservation and demand response resources to the portfolio.

Baseline: Conservation resources are selected when they are cost-effective.
Sensitivity Z > No conservation or demand response measures are included.

KEY FINDINGS. Without demand response or conservation, the cost of the Mid Scenario portfolio increases by $2.48 billion, building additional solar and storage resources to reach CETA compliance, and building two additional frame peakers to maintain peak capacity.

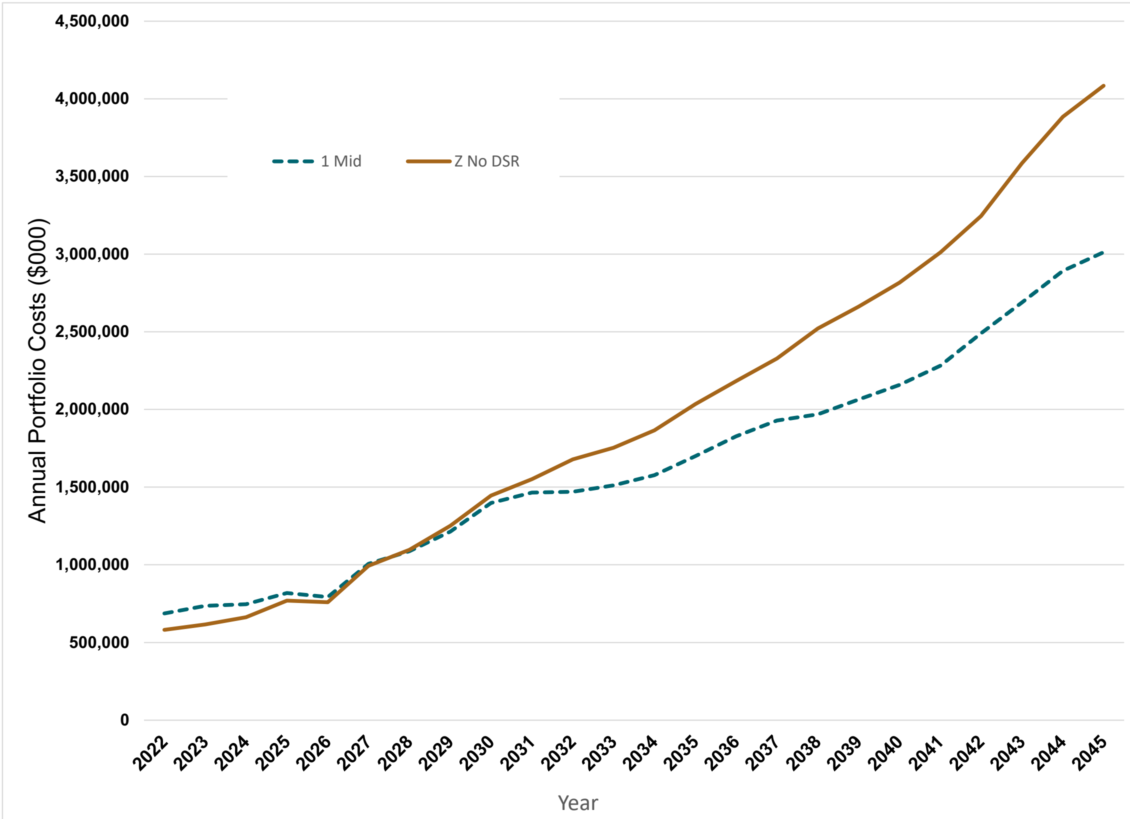
ASSUMPTIONS. Sensitivity Z keeps all the Mid Scenario modeling assumptions, except no conservation or demand response measures are included.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity Z and the Mid Portfolio are similar until 2030, when the removal of demand response and conservation from the portfolio reduce the costs of Portfolio Z. After 2030, growing demand that is unchecked by conservation measures combines with CETA renewable need to accelerate resource need and increase costs. Despite the up-front investment, DSR saves the Mid Scenario $2.48 billion by reducing demand and preventing the need for new resources, both renewable and thermal.

Figure 8-141: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Z

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Z	No DSR	$17.54	$5.56	$23.10	$2.48

Figure 8-142: Annual Portfolio Costs – Mid Scenario and Sensitivity Z



RESOURCE ADDITIONS. Figures 8-143 and 8-144 compares the nameplate capacity additions of the Mid Scenario and Sensitivity Z portfolios. To meet increased demand, Portfolio Z adds an additional two frame peakers (474 MW), 1,195 MW of eastern Washington solar, 250 MW of hybrid resources and 700 MW of 4- and 6-hour flow batteries by 2045. Solar builds begin to outpace the Mid Scenario as early as 2024, and a second round of builds enters late in the portfolio. For example, in Sensitivity Z, Washington wind capacity reaches 2,000 MW by 2039 with no further additions for the rest of the planning period compared to 1,500 MW of wind added in the Mid Scenario in 2039 which goes on to increase to 1,900 by 2045.

Figure 8-143: Portfolio Additions – Mid Scenario and Sensitivity Z

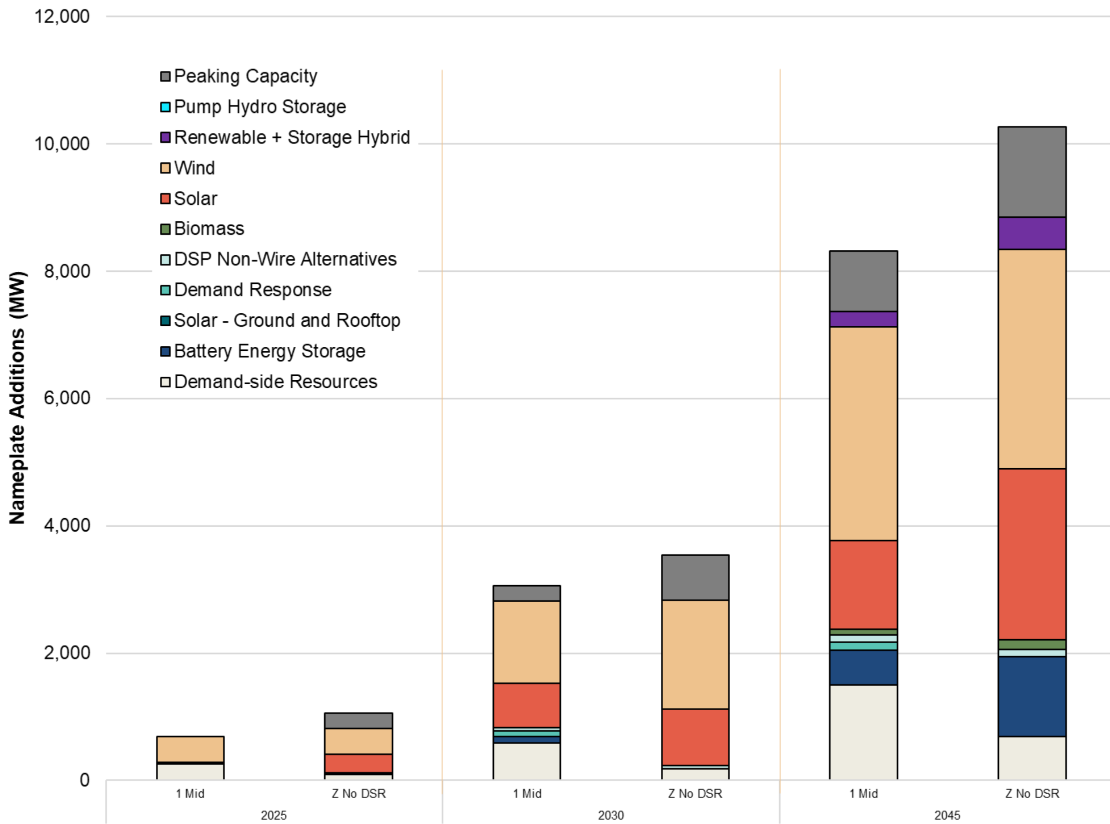


Figure 144: Portfolio Additions – Mid Scenario and Sensitivity Z

Resource Additions by 2045	1 Mid	Z No DSR
Demand-side Resources	1,497 MW	690 MW
Battery Energy Storage	550 MW	1,250 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	0 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,288 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,688 MW
Wind	3,350 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	1,422 MW

Other

AA. Montana Wind + Pumped Storage Hydro

This sensitivity examines the value of adding a hybrid resource early in the planning period.

Baseline: Hybrid resources are selected when they are cost-effective.
Sensitivity AA > A Montana wind plus pumped hydro storage hybrid resource is substituted for the eastern Montana wind resource added to the Mid Scenario in the year 2028.

KEY FINDINGS. Early addition of a hybrid Montana wind plus pumped hydro resource does not add meaningful value the portfolio. Portfolio costs are slightly higher and emissions remain the same or increase slightly. Peaking capacity additions are postponed by one or two years but are still added to the portfolio.

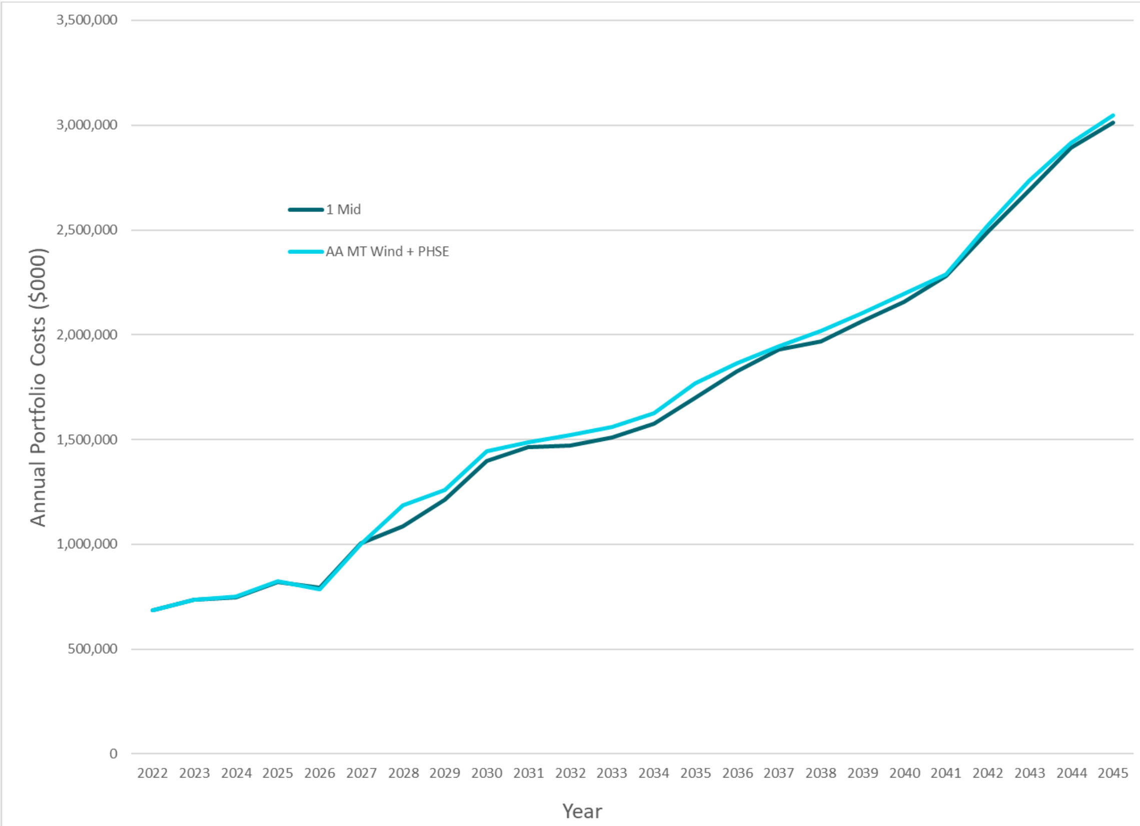
ASSUMPTIONS. Sensitivity AA keeps all the Mid Scenario modeling assumptions, except a Montana wind plus pumped storage hydro resource is forced into the portfolio in the year 2028.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity AA and the Mid Portfolio are similar except for the spike in revenue requirement in the year 2028 to purchase the Montana wind plus pumped hydro hybrid instead of the eastern Montana wind resource. The more costly revenue requirement of the hybrid resource is seen for the remainder of the planning period. Otherwise, portfolio costs are nearly identical.

Figure 8-145: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity AA

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
AA	MT wind + PHES	$15.84	$5.16	$20.99	$0.37

Figure 8-146: Annual Portfolio Costs – Mid Scenario and Sensitivity AA



RESOURCE ADDITIONS. Figures 8-147 and 8-148 compare the nameplate capacity additions of the Mid Scenario and Sensitivity AA portfolios. Resource additions are extremely similar between the two portfolios, the only notable differences being that Sensitivity AA adds the forced MT wind plus pumped hydro addition in 2028, 250 MW less independent storage and 300 MW less solar. Sensitivity AA adds peaking capacity on a slightly delayed schedule, but reaches the same amount of peaking capacity by 2045. Both portfolios select conservation Bundle 10.

Figure 8-147: Portfolio Additions – Mid Scenario and Sensitivity AA

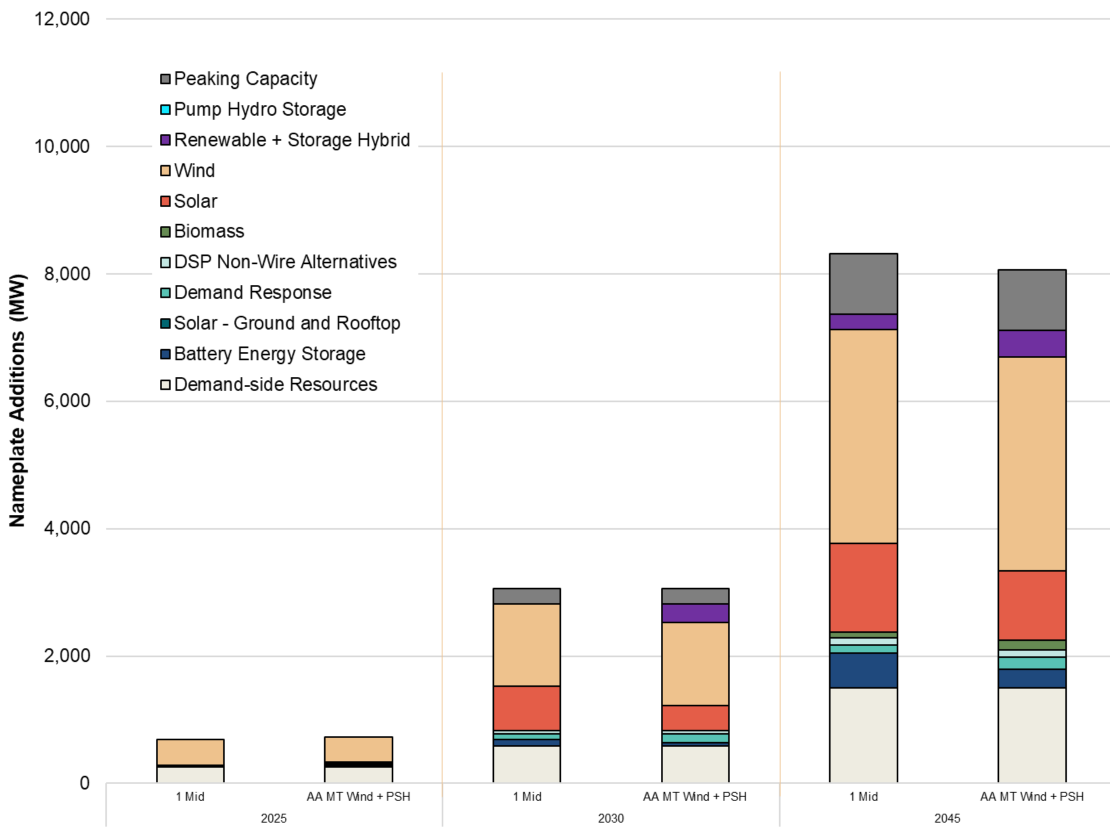
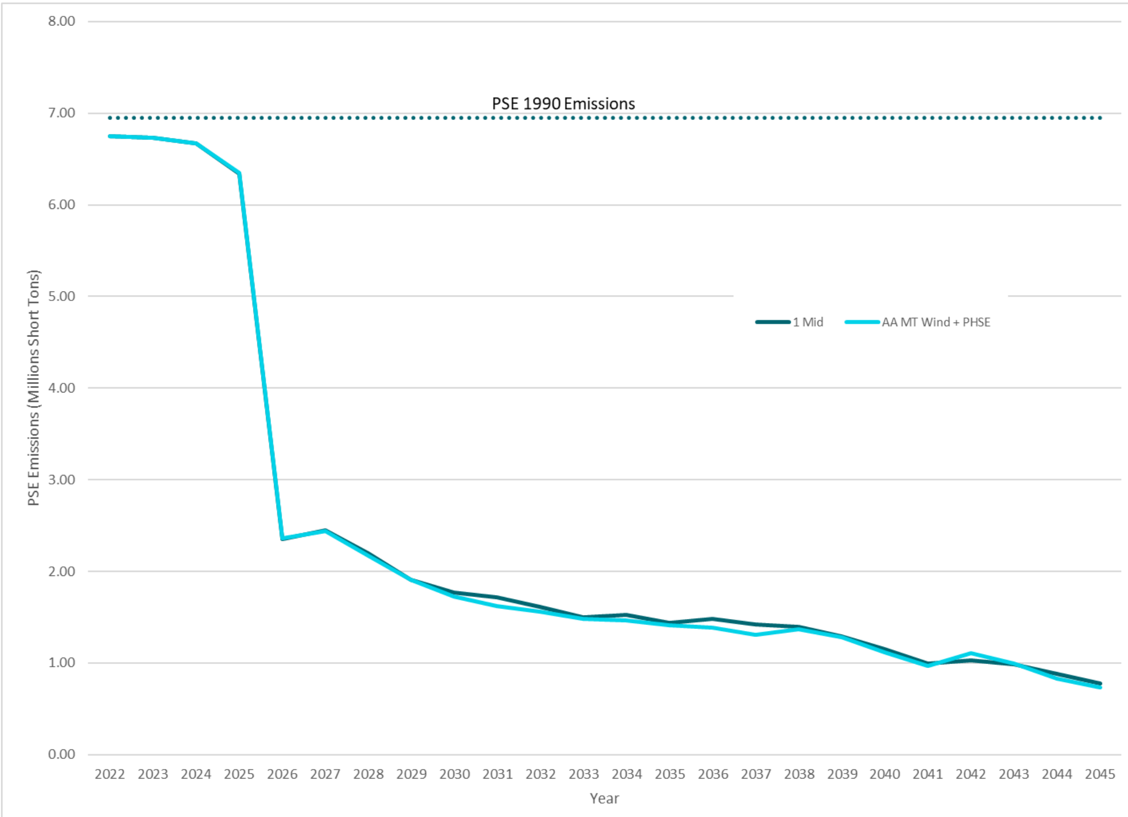


Figure 8-148: Portfolio Additions – Sensitivity AA

Resource Additions by 2045	1 Mid	AA MT Wind + PHES
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	300 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	182 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,594 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,094 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	425 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	948 MW

EMISSIONS. Figure 8-149 compares direct GHG emissions from Sensitivity AA to the Mid Scenario. Both portfolios have very similar direct emissions profiles.

Figure 8-149: Direct Emissions – Mid Scenario and Sensitivity AA



8. CUSTOMER BENEFITS ANALYSIS RESULTS

This section presents the results of the Customer Benefit Analysis. Not all portfolios were included in the Customer Benefit Analysis. To be included in the Customer Benefit Analysis, portfolios must meet the following criteria:

- Maintain consistency across demand and electric price forecasts
  - This criteria removed portfolios such as the Low and High Scenarios which varied demand and electric price inputs
- Must meet CETA requirements
  - This criteria removed portfolios such as Sensitivity T No CETA which does not include the CETA clean energy targets as a constraint.
- Represent current carbon regulation
  - This criteria removed portfolios such as Sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax, which models a federal carbon tax which is yet to be enacted.

These criteria limit the analysis to portfolios that are solving for the same fundamental goals and are built from the same fundamental inputs. In other words, it allows for an “apples to apples” comparison between all the selected portfolios. The Customer Benefit Analysis is described earlier in this chapter.

Customer Benefit Analysis results are presented for two timeframes, 2031 and 2045. These timeframes correspond to the 10-year Clean Energy Action Plan and 24-year IRP planning horizons, respectively. There is value in understanding how customer benefits evolve over the planning horizon of a portfolio, and benefits which only manifest themselves in the latest years of the planning horizon may hold less value, as these years hold the most uncertainty.

All Customer Benefit Analysis results and accompanying calculations are also provided in Appendix H.

Figures 8-150 and 8-151 present the portfolio outputs selected to represent customer benefit indicators (CBIs) for the 10-year and 24-year timeframes, respectively. These outputs have been color coded, from red (least benefit) to green (most benefit).

Figure 8-150: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	**Portfolio Cost ($ Billions, NPV)**	**SCGHG ($ Billions, NPV)**	**CO2 Emissions from Generation includes upstream emissions (Short tons)**	**SO2**	**NOx**	**PM**	**Market Purchases (MWh)**	**Utility Scale Renewable Generation (MWh)**	**Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)**	**Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)**	**Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)**	**Demand Response (Nameplate MW)**	**Distributed energy storage includes DSP NWA (Nameplate MW)**
1 Mid	$6.65	$3.43	1,706,536	15.5	695	51.7	2,993,778	12,937,098	3,270,127	42,882	1,251,124	88	138
A Renewable Overgeneration	$7.09	$3.06	1,041,372	8.6	953	30.4	3,469,768	12,388,236	3,299,397	42,882	1,244,115	148	288
C Distributed Transmission	$6.65	$3.47	1,715,375	15.4	1,450	54.1	3,416,731	12,836,902	3,314,803	73,753	1,250,796	137	38
D Transmission/build constraints - time delayed (option 2)	$6.68	$3.45	1,699,048	15.5	692	51.6	3,308,201	12,894,935	3,314,803	42,882	1,251,001	138	88
F 6-Yr DSR Ramp	$6.50	$3.45	1,686,148	15.3	683	51.1	3,226,151	12,933,532	3,246,695	42,882	1,251,092	133	163
G NEI DSR	$6.37	$3.48	1,718,391	15.7	704	52.2	3,161,303	12,831,265	3,158,255	42,882	1,251,120	145	38
H Social Discount DSR	$6.47	$3.51	1,719,776	15.7	704	52.2	3,147,714	13,145,403	2,839,232	42,882	1,251,122	109	63
I SCGHG Dispatch Cost - LTCE Model	$6.61	$3.44	1,696,923	15.4	684	51.5	3,367,791	12,722,327	3,270,127	42,882	1,251,025	138	38
K AR5 Upstream Emissions	$6.71	$3.48	1,726,261	15.6	702	52.0	3,081,879	12,830,732	3,270,127	42,882	1,251,107	102	88
M Alternative Fuel for Peakers - Biodiesel	$6.67	$3.40	1,517,306	13.1	535	43.9	3,318,592	12,731,439	3,314,803	42,882	1,251,103	137	113
N1 100% Renewable by 2030 Batteries	$10.86	$2.92	-	-	-	-	2,732,665	17,481,571	2,877,410	42,882	1,248,278	35	17,238
N2 100% Renewable by 2030 PSH	$19.92	$2.23	-	-	-	-	427,351	24,758,555	2,376,605	42,386	1,135,935	35	38
O1 100% Renewable by 2045 Batteries	$7.51	$3.46	1,491,992	12.7	497	42.6	3,361,916	13,363,504	2,879,010	42,882	1,251,094	93	6,138
O2 100% Renewable by 2045 PSH	$11.77	$2.86	1,435,497	12.1	457	40.6	1,418,112	16,378,053	3,314,519	42,882	1,250,372	175	38
P1 No Thermal Before 2030, 2Hr LiIon	$13.36	$3.88	1,866,880	20.3	1,358	68.6	5,804,376	12,305,127	3,158,254	42,882	1,243,305	136	3,738
P2 No Thermal Before 2030, PHES	$9.94	$3.19	1,457,354	12.4	479	41.5	2,691,465	14,828,639	2,878,642	42,882	1,250,530	88	663
P3 No Thermal Before 2030, 4Hr LiIon	$15.38	$3.91	1,868,834	20.9	1,490	71.4	6,659,481	11,885,433	3,158,254	42,882	1,240,394	94	3,963
V1 Balanced portfolio	$6.90	$3.42	1,617,639	14.3	862	48.6	2,975,094	11,888,235	3,270,127	428,908	2,089,041	195	238
V2 Balanced portfolio + MT Wind and PSH	$7.13	$3.43	1,596,777	14.1	600	47.1	3,366,392	11,375,806	3,270,127	428,908	2,089,066	195	313
V3 Balanced portfolio + 6 Year DSR	$6.84	$3.39	1,677,083	15.2	675	50.7	3,039,097	11,789,240	3,246,695	428,908	2,089,039	195	213
W Preferred Portfolio (BP with Biodiesel)	$6.91	$3.39	1,531,671	13.2	787	44.9	3,011,301	12,726,398	3,270,127	428,908	1,251,118	195	238
AA MT Wind + PHSE	$6.78	$3.45	1,610,870	14.3	613	47.8	3,297,371	12,633,279	3,270,127	42,882	1,251,134	139	88

Figure 8-151: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	$15.53	$5.02	777,018	7.6	395	25.1	2,523,005	21,177,795	5,969,983	355,423	656,726	123	639
A Renewable Overgeneration	$17.11	$4.39	348,728	3.6	2,027	18.3	3,158,061	19,067,643	5,894,513	355,423	656,726	192	1,614
C Distributed Transmission	$16.35	$5.14	1,000,086	9.7	945	33.7	2,946,470	16,652,161	6,112,842	4,351,476	656,726	178	1,139
D Transmission/build constraints - time delayed (option 2)	$15.54	$5.04	719,068	7.1	376	23.5	2,819,871	21,031,995	6,099,281	355,423	656,726	180	739
F 6-Yr DSR Ramp	$15.54	$5.09	773,251	7.5	519	25.5	2,571,955	21,697,533	5,460,256	355,423	656,726	175	714
G NEI DSR	$15.24	$5.12	784,118	7.8	406	26.1	2,542,855	21,703,446	5,455,750	355,423	656,726	188	539
H Social Discount DSR	$15.77	$5.16	729,330	7.2	375	23.8	2,716,481	21,983,087	5,082,505	355,423	656,726	195	764
I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.03	701,528	6.7	759	23.6	2,691,320	21,067,257	5,987,446	355,423	656,726	188	964
K AR5 Upstream Emissions	$15.56	$5.07	790,955	7.6	383	25.4	2,449,467	21,147,646	5,985,551	355,423	656,726	140	714
M Alternative Fuel for Peakers - Biodiesel	$15.44	$4.90	618,707	5.5	244	18.2	2,585,949	20,984,943	6,110,420	355,423	656,726	185	789
N1 100% Renewable by 2030 Batteries	$32.03	$3.71	-	-	-	-	2,825,792	22,610,060	5,046,629	355,423	656,726	59	26,289
N2 100% Renewable by 2030 PSH	$66.64	$2.48	-	-	-	-	1,949,508	25,678,395	4,219,612	355,386	656,726	59	89
O1 100% Renewable by 2045 Batteries	$23.35	$4.81	-	-	-	-	3,023,029	22,350,832	5,046,580	355,413	656,726	128	24,589
O2 100% Renewable by 2045 PSH	$46.95	$3.98	-	-	-	-	2,654,604	21,421,254	6,145,637	355,423	656,726	204	89
P1 No Thermal Before 2030, 2Hr LiIon	$30.84	$6.29	1,279,104	15.0	1,087	50.9	4,411,218	20,568,897	5,427,472	355,423	656,726	178	4,389
P2 No Thermal Before 2030, PHES	$22.85	$4.71	613,093	5.4	393	18.4	2,743,151	22,366,284	5,029,928	355,423	656,726	122	1,114
P3 No Thermal Before 2030, 4Hr LiIon	$39.01	$6.60	1,432,066	16.1	1,150	54.8	5,031,036	20,040,561	5,428,824	355,423	656,726	129	4,514
V1 Balanced portfolio	$16.06	$5.00	759,074	7.4	502	25.1	2,536,212	19,117,749	5,971,509	1,552,256	1,493,182	217	539
V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.06	833,441	8.2	427	27.3	2,516,854	18,879,956	5,969,903	1,550,653	1,493,182	217	464
V3 Balanced portfolio + 6 Year DSR	$16.26	$4.99	797,220	7.7	761	26.8	2,566,699	19,606,509	5,462,125	1,552,389	1,493,182	217	764
W Preferred Portfolio (BP with Biodiesel)	$16.11	$4.90	608,762	5.4	363	18.3	2,589,643	19,960,322	5,971,509	1,552,256	656,726	217	539
AA MT Wind + PHSE	$15.84	$5.09	733,210	7.2	379	23.9	2,657,404	20,940,400	5,969,607	355,423	656,726	182	389

Figures 8-152 and 8-153 rank each of the selected portfolios on each of the CBIs for the 10-year and 24-year timeframes, respectively.

Figure 8-152: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	6	11	16	17	13	16	6	7	6	6	5	19	12
A Renewable Overgeneration	14	4	3	3	19	3	20	17	5	20	19	6	7
C Distributed Transmission	5	17	17	14	21	20	19	10	1	5	15	11	18
D Transmission/build constraints - time delayed (option 2)	8	14	15	16	12	15	14	9	1	6	14	9	14
F 6-Yr DSR Ramp	3	15	13	13	10	13	12	8	13	6	12	14	11
G NEI DSR	1	19	18	19	16	18	11	11	15	6	7	7	18
H Social Discount DSR	2	20	19	20	15	19	10	6	21	6	6	15	17
I SCGHG Dispatch Cost - LTCE Model	4	12	14	15	11	14	18	15	6	6	13	10	18
K AR5 Upstream Emissions	9	18	20	18	14	17	9	12	6	6	9	16	14
M Alternative Fuel for Peakers - Biodiesel	7	8	7	7	6	7	15	13	1	6	10	11	13
N1 100% Renewable by 2030 Batteries	18	3	1	1	1	1	4	2	20	17	18	21	1
N2 100% Renewable by 2030 PSH	22	1	1	1	1	1	1	1	22	22	22	21	18
O1 100% Renewable by 2045 Batteries	16	16	6	6	5	6	16	5	18	6	11	18	2
O2 100% Renewable by 2045 PSH	19	2	4	4	3	4	2	3	4	17	17	5	18
P1 No Thermal Before 2030, 2Hr LiIon	20	21	21	21	20	21	21	18	16	19	20	13	4
P2 No Thermal Before 2030, PHES	17	5	5	5	4	5	3	4	19	6	16	20	5
P3 No Thermal Before 2030, 4Hr LiIon	21	22	22	22	22	22	22	20	17	20	21	17	3
V1 Balanced portfolio	12	9	11	10	18	11	5	19	6	1	2	1	8
V2 Balanced portfolio + MT Wind and PSH	15	10	9	9	7	9	17	22	6	1	1	1	6
V3 Balanced portfolio + 6 Year DSR	11	6	12	12	9	12	8	21	13	1	3	1	10
W Preferred Portfolio (BP with Biodiesel)	13	7	8	8	17	8	7	14	6	1	8	1	8
AA MT Wind + PHSE	10	13	10	11	8	10	13	16	6	6	4	8	14

Figure 8-153: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	**Portfolio Cost ($ Billions, NPV)**	**SCGHG ($ Billions, NPV)**	**CO2 Emissions from Generation includes upstream emissions (Short tons)**	**SO2**	**NOx**	**PM**	**Market Purchases (MWh)**	**Utility Scale Renewable Generation (MWh)**	**Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)**	**Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)**	**Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)**	**Demand Response (Nameplate MW)**	**Distributed energy storage includes DSP NWA (Nameplate MW)**
1 Mid	4	11	15	15	12	14	4	9	9	13	4	19	15
A Renewable Overgeneration	15	4	5	5	22	7	20	20	12	20	4	7	5
C Distributed Transmission	13	19	20	20	19	20	18	22	2	1	4	13	6
D Transmission/build constraints - time delayed (option 2)	6	13	10	10	8	9	16	12	4	9	4	12	12
F 6-Yr DSR Ramp	5	16	14	14	16	16	8	7	14	13	4	15	13
G NEI DSR	1	18	16	18	13	17	6	6	15	13	4	8	16
H Social Discount DSR	8	20	11	11	7	11	14	5	18	9	4	6	10
I SCGHG Dispatch Cost - LTCE Model	2	12	9	9	17	10	13	11	5	9	4	9	8
K AR5 Upstream Emissions	7	15	17	16	10	15	2	10	6	13	4	16	13
M Alternative Fuel for Peakers - Biodiesel	3	8	8	8	5	5	9	13	3	9	4	10	9
N1 100% Renewable by 2030 Batteries	19	2	1	1	1	1	17	2	19	7	4	21	1
N2 100% Renewable by 2030 PSH	22	1	1	1	1	1	1	1	22	22	4	21	21
O1 100% Renewable by 2045 Batteries	17	6	1	1	1	1	19	4	20	21	4	18	2
O2 100% Renewable by 2045 PSH	21	3	1	1	1	1	11	8	1	7	4	5	21
P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	20	21	21	15	17	18	4	14	4
P2 No Thermal Before 2030, PHES	16	5	7	7	11	8	15	3	21	6	4	20	7
P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	21	22	22	16	16	18	4	17	3
V1 Balanced portfolio	10	10	13	13	15	13	5	19	8	3	1	1	16
V2 Balanced portfolio + MT Wind and PSH	14	14	19	19	14	19	3	21	10	5	1	1	19
V3 Balanced portfolio + 6 Year DSR	12	9	18	17	18	18	7	18	13	2	1	1	10
W Preferred Portfolio (BP with Biodiesel)	11	7	6	6	6	6	10	17	7	3	4	1	16
AA MT Wind + PHSE	9	17	12	12	9	12	12	14	11	13	4	11	20

Figures 8-154 and 8-155 aggregate CBIs into customer benefit indicator areas and determine an overall portfolio rank from the seven CBI areas for the 10-year and 24-year timeframes, respectively.

Figure 8-154: 10-year Customer Benefit Analysis –
Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
12	1 Mid	6	14	15	6	6	19	12	11.1
9	A Renewable Overgeneration	14	4	8	20	15	6	7	10.6
20	C Distributed Transmission	5	17	18	19	8	11	18	13.7
15	D Transmission/build constraints - time delayed (option 2)	8	15	14	14	8	9	14	11.6
11	F 6-Yr DSR Ramp	3	14	12	12	10	14	11	10.8
16	G NEI DSR	1	19	18	11	10	7	18	11.8
18	H Social Discount DSR	2	20	18	10	10	15	17	13.0
17	I SCGHG Dispatch Cost - LTCE Model	4	13	13	18	10	10	18	12.3
19	K AR5 Upstream Emissions	9	19	16	9	8	16	14	13.1
8	M Alternative Fuel for Peakers - Biodiesel	7	8	7	15	8	11	13	9.7
5	N1 100% Renewable by 2030 Batteries	18	2	1	4	14	21	1	8.8
14	N2 100% Renewable by 2030 PSH	22	1	1	1	17	21	18	11.5
13	O1 100% Renewable by 2045 Batteries	16	11	6	16	10	18	2	11.2
4	O2 100% Renewable by 2045 PSH	19	3	4	2	10	5	18	8.7
21	P1 No Thermal Before 2030, 2Hr LiIon	20	21	21	21	18	13	4	16.8
7	P2 No Thermal Before 2030, PHES	17	5	5	3	11	20	5	9.4
22	P3 No Thermal Before 2030, 4Hr LiIon	21	22	22	22	20	17	3	18.1
2	V1 Balanced portfolio	12	10	13	5	7	1	8	8.0
6	V2 Balanced portfolio + MT Wind and PSH	15	10	8	17	8	1	6	9.2
3	V3 Balanced portfolio + 6 Year DSR	11	9	11	8	10	1	10	8.5
1	W Preferred Portfolio (BP with Biodiesel)	13	8	11	7	7	1	8	7.8
10	AA MT Wind + PHSE	10	12	10	13	8	8	14	10.6

Figure 8-155: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
14	1 Mid	4	13	14	4	9	19	15	11.1
13	A Renewable Overgeneration	15	5	11	20	14	7	5	11.0
20	C Distributed Transmission	13	20	20	18	7	13	6	13.8
11	D Transmission/build constraints - time delayed (option 2)	6	12	9	16	7	12	12	10.5
17	F 6-Yr DSR Ramp	5	15	15	8	10	15	13	11.5
10	G NEI DSR	1	17	16	6	10	8	16	10.5
8	H Social Discount DSR	8	16	10	14	9	6	10	10.3
3	I SCGHG Dispatch Cost - LTCE Model	2	11	12	13	7	9	8	8.8
12	K AR5 Upstream Emissions	7	16	14	2	8	16	13	10.8
1	M Alternative Fuel for Peakers - Biodiesel	3	8	6	9	7	10	9	7.5
6	N1 100% Renewable by 2030 Batteries	19	2	1	17	8	21	1	9.8
15	N2 100% Renewable by 2030 PSH	22	1	1	1	12	21	21	11.3
9	O1 100% Renewable by 2045 Batteries	17	4	1	19	12	18	2	10.4
5	O2 100% Renewable by 2045 PSH	21	2	1	11	5	5	21	9.4
21	P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	14	14	4	16.0
18	P2 No Thermal Before 2030, PHES	16	6	9	15	9	20	7	11.6
22	P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	14	17	3	17.0
4	V1 Balanced portfolio	10	12	14	5	8	1	16	9.3
16	V2 Balanced portfolio + MT Wind and PSH	14	17	17	3	9	1	19	11.4
7	V3 Balanced portfolio + 6 Year DSR	12	14	18	7	9	1	10	10.0
2	W Preferred Portfolio (BP with Biodiesel)	11	7	6	10	8	1	16	8.3
19	AA MT Wind + PHSE	9	15	11	12	11	11	20	12.6

Figure 8-156 summarizes the overall portfolio rank for both the 10-year and 24-year timeframes. Generally, portfolios that ranked well in the 10-year timeframe also ranked well in the 24-year timeframe. However, there are notable exceptions, including Sensitivities I and P2.

Sensitivity I modeled the SCGHG as a dispatch cost in the LTCE model. Sensitivity I has a poorer overall rank in the 10-year timeframe but improves to be among the top-ranked portfolios in the 24-year timeframe. This suggests that Environmental and Resiliency benefits, which this portfolio ultimately scores well in, do not provide meaningful benefits until the end of the modeling horizon, and that other portfolios should be considered to deliver benefits as early as possible.

Sensitivity P2 forced the selection of pumped hydro storage resources before any flexible capacity could be added to the portfolio. Sensitivity P2 is a well-ranked portfolio in the 10-year timeframe but drops to near the bottom of the rankings in the 24-year time horizon. This suggests that too much focus on early adoption of storage resources is a costly endeavor that sets up the portfolio to be reliant on large quantities of market purchases to charge the storage resources.

Figure 8-156: Overall Portfolio Rank by 10-year and 24-year Timeframe

	10-year	24-year
1 Mid	12	14
A Renewable Overgeneration	9	13
C Distributed Transmission	20	20
D Transmission/build constraints - time delayed (option 2)	15	11
F 6-Yr DSR Ramp	11	17
G NEI DSR	16	10
H Social Discount DSR	18	8
I SCGHG Dispatch Cost - LTCE Model	17	3
K AR5 Upstream Emissions	19	12
M Alternative Fuel for Peakers - Biodiesel	8	1
N1 100% Renewable by 2030 Batteries	5	6
N2 100% Renewable by 2030 PSH	14	15
O1 100% Renewable by 2045 Batteries	13	9
O2 100% Renewable by 2045 PSH	4	5
P1 No Thermal Before 2030, 2Hr LiIon	21	21
P2 No Thermal Before 2030, PHES	7	18
P3 No Thermal Before 2030, 4Hr LiIon	22	22
V1 Balanced portfolio	2	4
V2 Balanced portfolio + MT Wind and PSH	6	16
V3 Balanced portfolio + 6 Year DSR	3	7
W Preferred Portfolio (BP with Biodiesel)	1	2
AA MT Wind + PHSE	10	19

As shown in Figure 8-156, the Customer Benefit Analysis suggests Sensitivity M as the portfolio that provides the greatest benefit to PSE customers in the 24-year IRP timeframe. PSE recognizes that this portfolio has many desirable attributes including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits. Therefore, PSE has selected Sensitivity W Balanced Portfolio with Biodiesel as the preferred portfolio. Sensitivity W provides many of the same benefits as Sensitivity M, but also includes greater investment in distributed energy resources. Furthermore, Sensitivity W is shown to provide the greatest benefit in the 10-year CEAP timeframe. This shows that early investment in these distributed resources provides benefits over the entire span of the modeling horizon, whereas Sensitivity M benefits are realized most strongly in the later years.

9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. To achieve this purpose, PSE runs select portfolios through 310 simulations, or draws,[7] that vary power prices, gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can quantify the risk of each portfolio. Four different portfolios were tested in the stochastic portfolio analysis. Figure 8-xx describes the four different portfolios.

Figure 8-157: Portfolios Tested for Stochastic Analysis

Portfolios Tested for Stochastic Analysis		
1	Mid Scenario	This is the optimal portfolio for the Base Scenario. It includes frame peakers for capacity and solar for the RPS.
W	Balanced Portfolio with Alternative Fuel for Peakers	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel, along with a reduced access to the Mid-C market for both sales and purchases.
Z	No DSR	This portfolio is from the no DSR sensitivity.

7 / Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power and Conservation Council (NPCC) in its power plans.

PSE also looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed-cost recovery for existing assets. The annual volatility data can be found in Appendix H, Electric Analysis Inputs and Results.

Stochastic Results

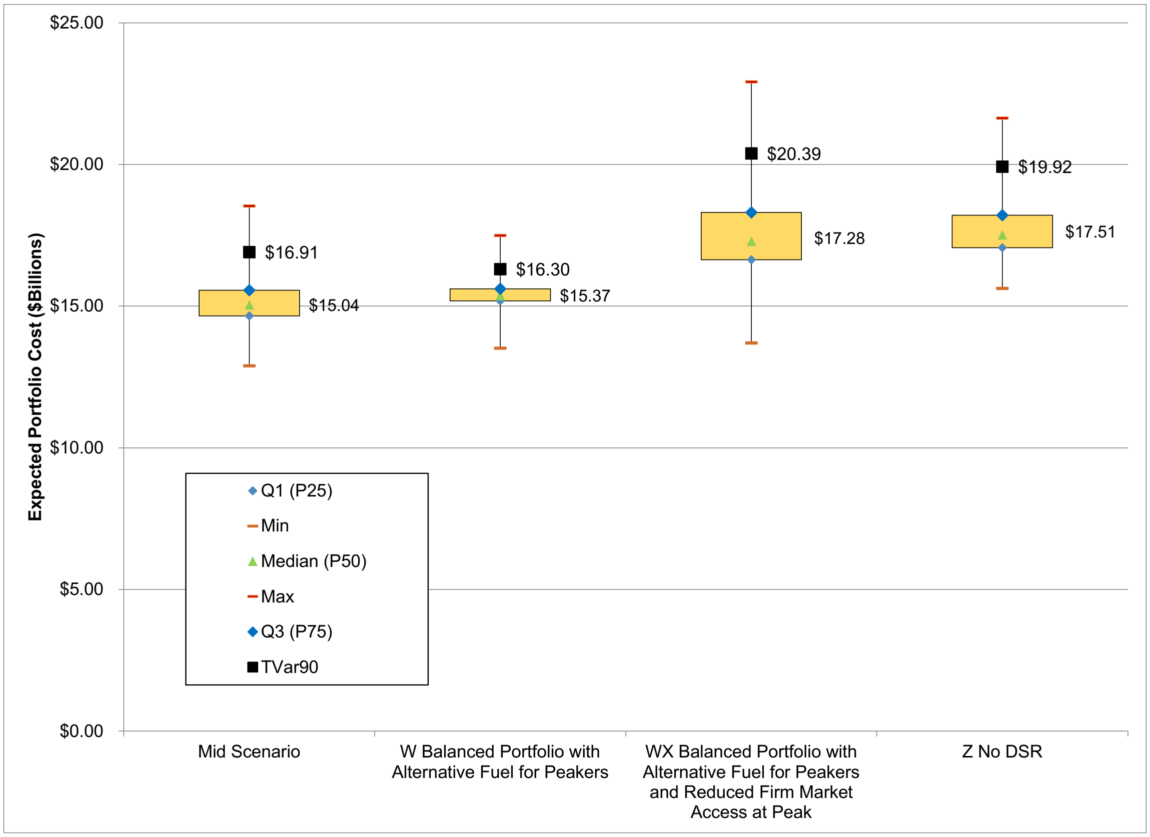
PSE's approach to the electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information available through the Request for Proposal and other acquisition processes. Nevertheless, the result of the risk simulation provides an indication of portfolio costs risk range under varying input assumptions. Figure 8-158 shows a comparison of the 24-year levelized costs for the deterministic run, the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for all 4 portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model run for 3 of the portfolios except for the No DSR portfolio.

Figure 8-158: Portfolio Costs across 310 Simulations

		24-year Levelized Costs (Billion $)					
Revenue Requirement	**Portfolio**	**Deterministic**	**Difference from Mid**	**Mean**	**Difference from Mid**	**TVar90**	**Difference from Mid**
1	**Mid Scenario**	$15.53	--	$15.18	--	$16.91	--
W	**Balanced Portfolio with Alternative Fuel for Peakers**	$16.10	$0.57	$15.42	$0.24	$16.30	($0.60)
WX	**Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak**	$18.78	$3.25	$17.53	$2.34	$20.39	$3.49
Z	**No DSR**	$17.54	$2.01	$17.74	$2.56	$19.92	$3.01

Figure 8-159 compares the expected portfolio costs for each portfolio. The vertical axis represents the costs and the horizontal axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

Figure 8-159: Range of Portfolio Costs across 310 Simulations



Key results of the analysis include:

- The interquartile range for Sensitivity W is comparatively narrow and has the lowest TailVar90 at $16.3 billion, suggesting that the overall expected portfolio costs are the least variable compared to the other portfolios.
- Sensitivity WX has the widest interquartile range and the highest TailVar90 at $20.4 billion, suggesting the highest risk in portfolio costs variability. With the reduction of market access, the risk shifts from Mid-C market price volatility to natural gas price volatility. Thermal resources replace the energy that is no longer available from the market. Portfolio fuel costs may increase or decrease depending on the simulation.
- In Sensitivity Z, the mean of the 310 simulations is $17.7 billion, which is $0.2 billion higher than the deterministic portfolio costs. In comparison to the Mid Scenario, the mean and the deterministic portfolio costs are higher for Sensitivity Z. This suggests that demand-side resources reduce both cost and market risk in portfolios.

Figures 8-160 to 8-161 below show the frequency distribution of portfolio cost for selected portfolios. Portfolio cost results for each simulation are sorted into “bins,” with each bin containing a narrow range of expected portfolio costs.

Figure 8-160 compares the Mid Scenario to Sensitivity W. The shorter right-hand tail and lower TailVar90 value of Sensitivity W indicate there is less risk associated with Sensitivity W than the Mid Scenario, despite the higher average portfolio cost.

Figure 8-160: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity W

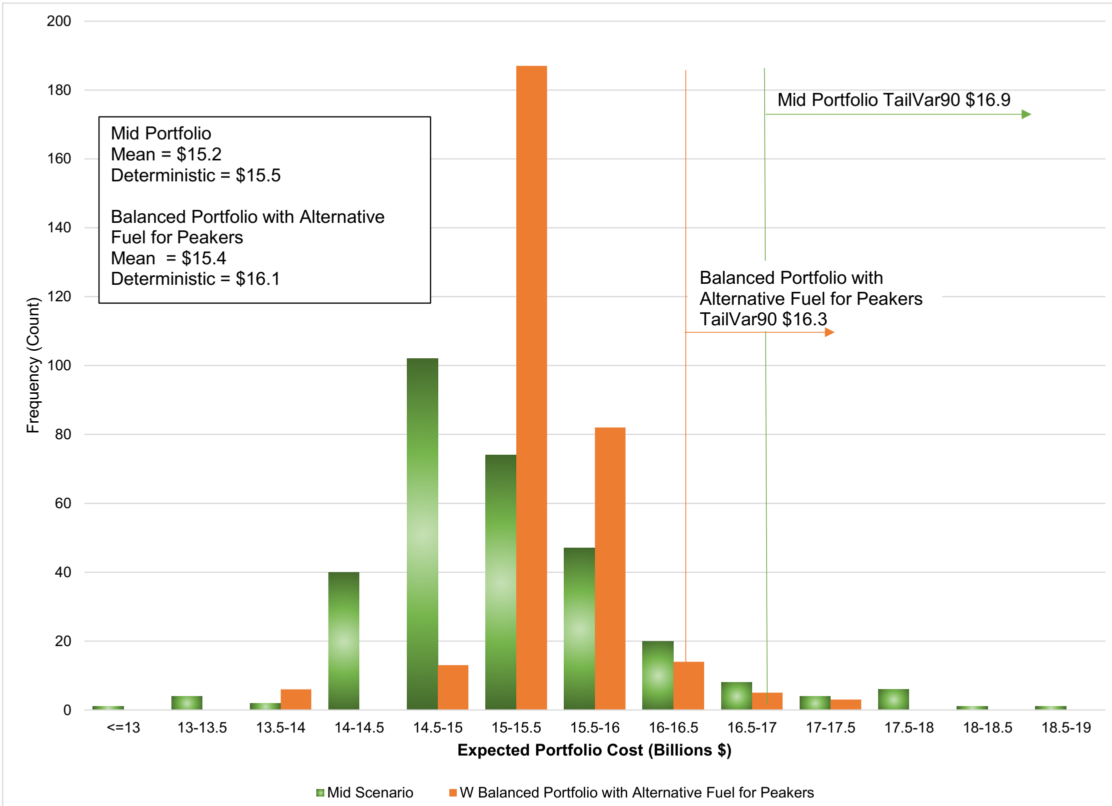


Figure 8-161 compares the Mid Scenario with Sensitivity Z. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity Z indicate the demand-side resources are an effective way to reduce both portfolio cost and risk.

Figure 8-161: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity Z

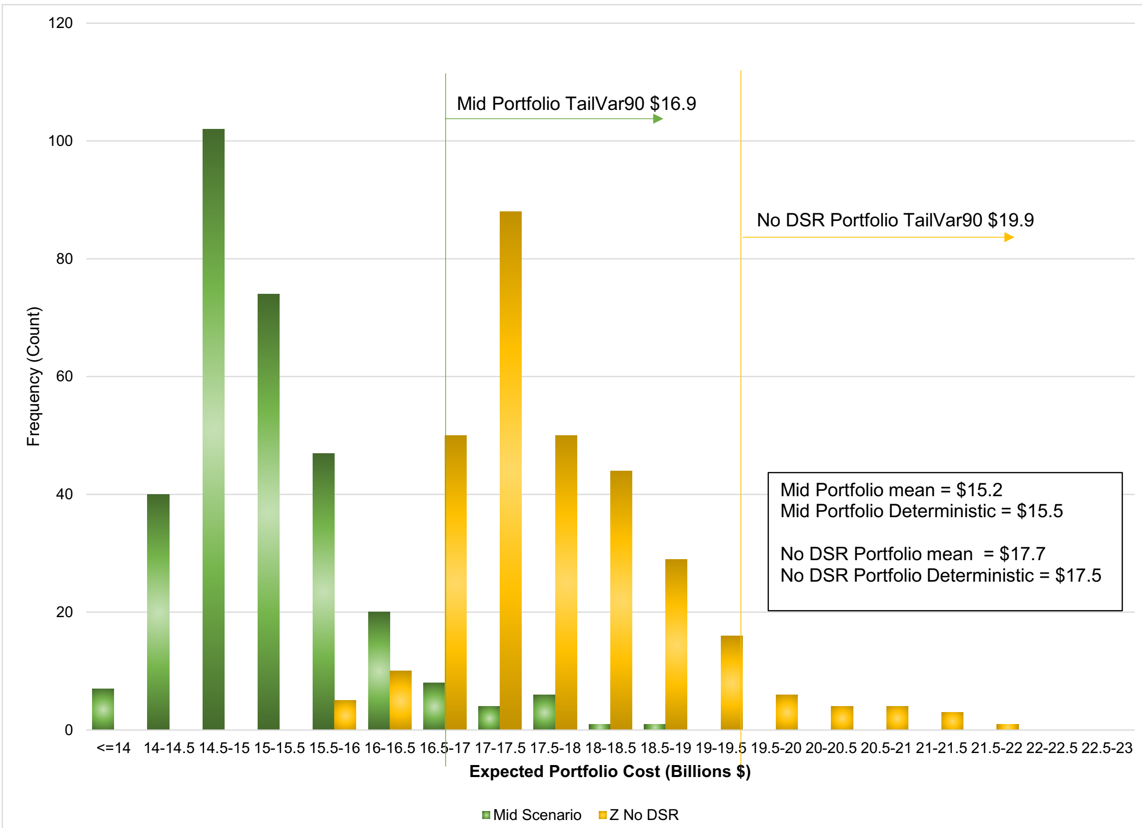
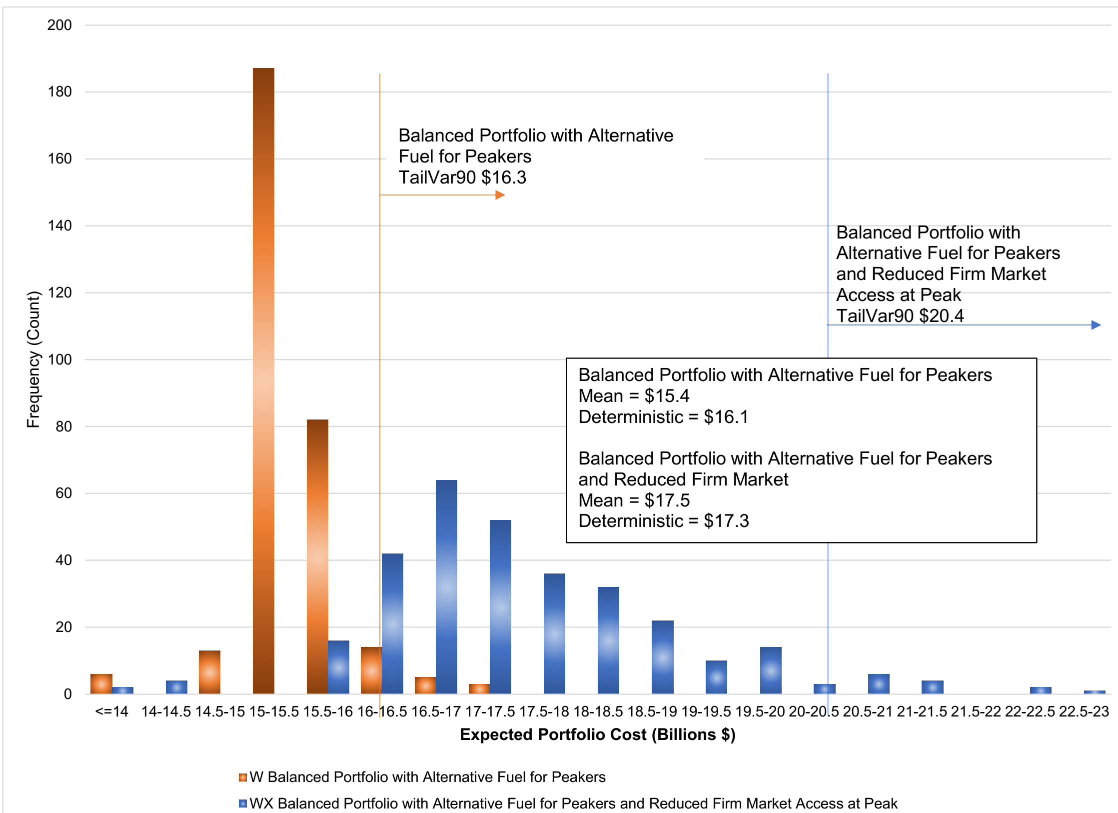


Figure 8-162 compares Sensitivity W with Sensitivity WX. The only difference between Sensitivity W and Sensitivity WX is the reduced access to market purchases during peak demand in Sensitivity WX. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity WX show that it is both more costly and riskier than the Sensitivity W. As stated above, this added risk is associated with volatility of natural gas prices to fuel thermal resources used to replace market purchases during peak demand. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

Figure 8-162: Frequency Histogram of Expected Portfolio Cost (Billions $) – Preferred Portfolio vs. Preferred Portfolio with Market Reduction



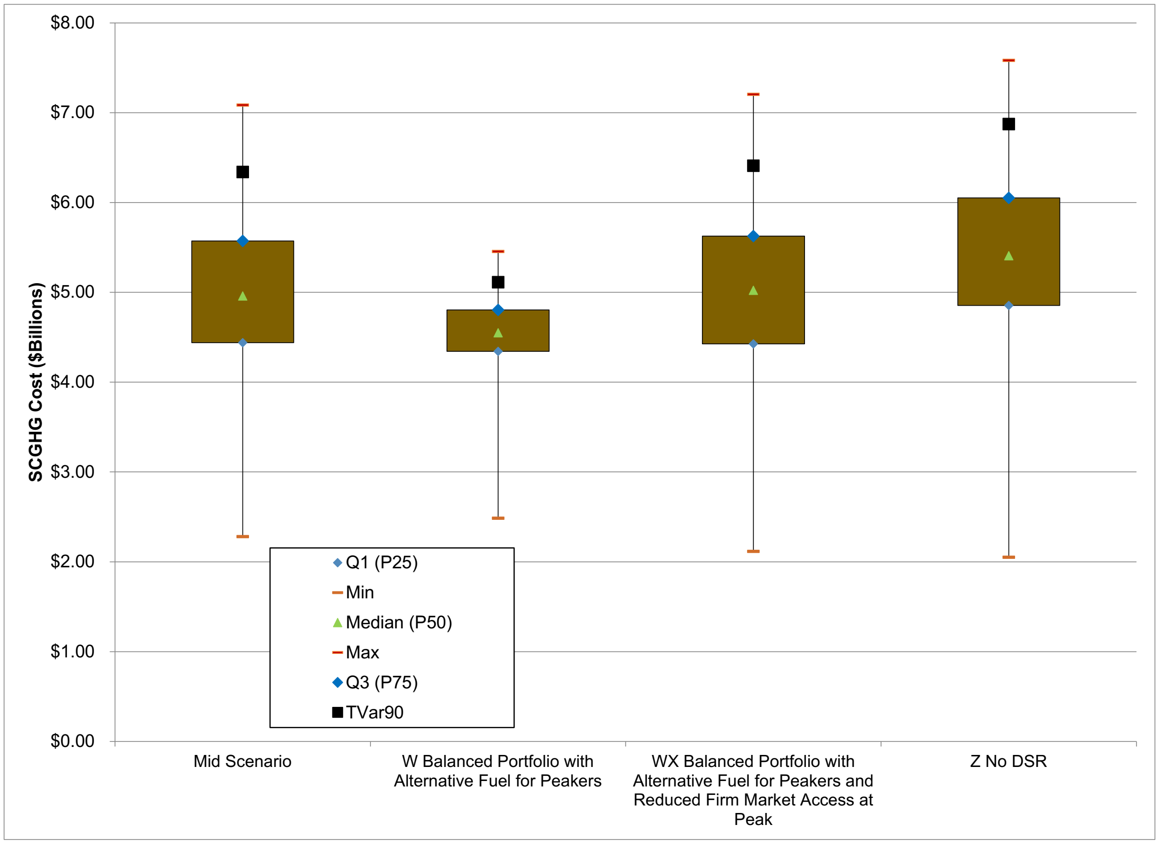
In addition to the expected portfolio costs, PSE also evaluated the expected SCGHG. Figure 8-163 and 8-164 below show a comparison of the 24-year levelized emissions costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of all 4 portfolios.

Results are similar to the portfolio cost results discussed above. Sensitivity W shows the narrowest, and therefore least-risk, range of SCGHG.

Figure 8-163: SCGHG across 310 Simulations

		24-year Levelized Costs (Billion $)					
SCGHG	**Portfolio**	**Emissions**	**Difference from Mid**	**Mean**	**Difference from Mid**	**TVar90**	**Difference from Mid**
1	Mid Scenario	$5.09	--	$4.98	--	$4.98	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$4.96	($0.13)	$4.54	($0.44)	$4.54	($0.44)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$4.74	($0.35)	$5.02	$0.47	$6.41	$1.43
Z	No DSR	$5.56	$0.47	$5.42	$0.41	$6.87	$1.90

Figure 8-164: Range of SCGHG across 310 Simulations



10. ELECTRIC DELIVERY SYSTEM ANALYSIS

Overview

PSE's electric delivery system is responsible for delivering electricity safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, we must do the following.[8]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at a local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Meet the interconnection needs of independent power generators and customers that choose to connect and provide energy to our system.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so 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.

8 / These obligations are defined by various codes and best practices such as Washington Administrative Code (WAC) 296 - 45 Electric Power Generation, Transmission, and Distribution; 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.

Ever more important today is to ensure that the system is flexible enough to adapt to coming changes. Smart and flexible equipment, customer distributed resources and demand response programs are some of the effective solutions the industry is moving toward, and PSE's electric delivery system needs to be prepared to integrate them for the benefit of our customers. Figure 8-XX depicts PSE's grid modernization framework for electric system improvements.

Figure 8-165: Grid Modernization Framework

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.

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as reliability indices, company goals and commitments, and the root causes of historic outages. External inputs include service quality indices, regulations, municipalities' infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. 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.

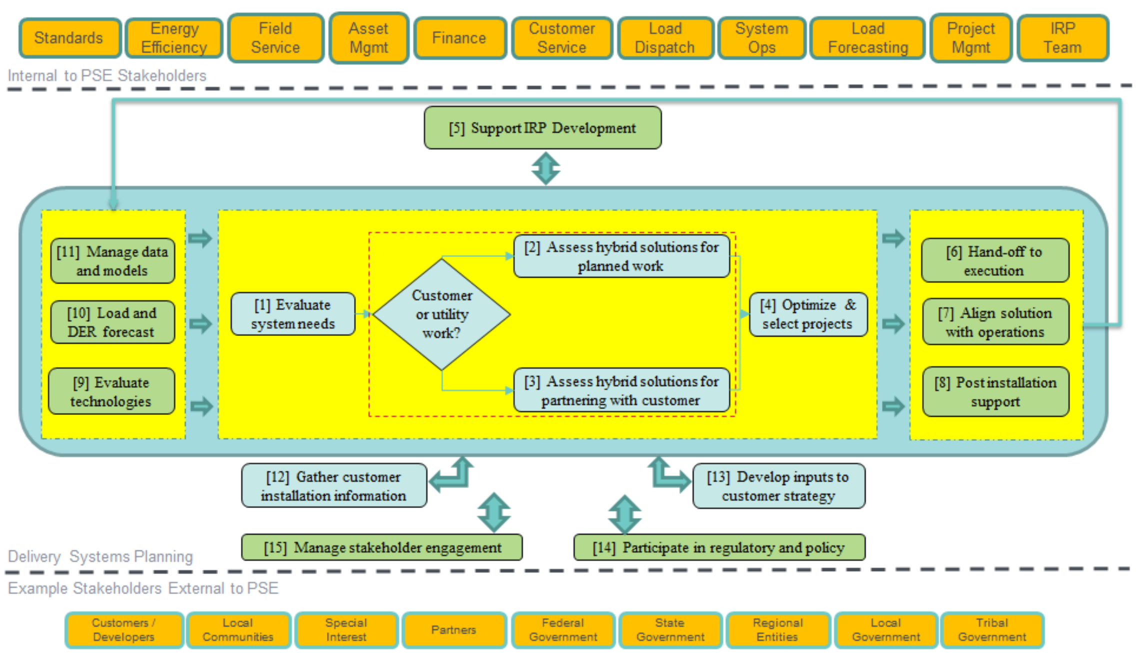
Key Findings

PSE's 10-year plan is included as Appendix M of this IRP.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 8-166 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 8-166: PSE Delivery System Planning Operating Model



Electric delivery system needs are driven by a number of different key factors as described below. All of these factors to be considered to identify the right needs across the system.

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area. For example, PSE has requests from several data centers, industrial facilities, etc., that plan to connect in the next few years with projected loads between 5 and 15 MW.

Energy efficiency consists of measures and programs that replace existing building energy using components and systems such as lighting, heating, water heating, insulation, appliances, etc., with more energy efficient ones. These replacements can reduce both peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress, system imbalance or in response to market prices are participating in demand response (DR). Interruptible rates are a subset of demand response. When used to relieve loading at critical times, demand response can offset anticipated loads and reduce the need for traditional delivery infrastructure. Interruptible rates are used in PSE's service area, and there is a high dependence on curtailment of these customers in order to meet demand.

RESOURCE INTEGRATION. 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 facility, 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. Also, if natural gas is the generation feedstock, large plants will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life and is incapable of supporting the digitization of the grid includes substation assets, circuit breakers and remote terminal units. Assets whose age and condition create reliability and resilience issues include direct buried high molecular weight underground distribution cable, poles and cross arms, and substation transformers.

RELIABILITY. Improving areas across the delivery system to minimize both the total number and duration of outages is important to customers today. This will become increasingly important in a modern grid as we anticipate customers will be even more reliant on electrical power as transformation such as transportation conversions continue to occur.

OPERATIONAL FLEXIBILITY. The ability to switch circuits to transfer load is important in responding to unplanned and planned outages, and the ability to perform necessary maintenance on equipment.

DISTRIBUTED ENERGY RESOURCES. At sufficient scale, distributed energy resources such as roof-top solar can reduce demand or provide operational flexibility. If uncontrolled, they can increase demand such as charging batteries during peak times or triggering voltage or power quality concerns if there are too many or they don't operate appropriately.

SAFETY AND REGULATORY REQUIREMENTS. These requirements drive action for mitigation in short order and/or are dictated through contractual agreements and as a result are identified and resolved outside of this long term planning process.

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outage experience, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements bring the most customer benefit. PSE collects system performance information from field charts, remote telemetry units, 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. PSE gives additional consideration to system enhancements that will improve resiliency, such as the ability to deliver electricity via a second line, possibly from another substation, to make the grid more self-healing. Programs are also in place to address aging infrastructure by replacing poles and other components that are nearing the end of their useful life.

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 and Grid Modernization strategy, are also included in the system 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. PSE also collects 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. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost.

PSE actively reviews and evaluates new technologies that can support delivery system needs. These technologies are identified, cataloged, and evaluated by an internal, cross-functional group of experts for business alignment, potential value, and feasibility. Cybersecurity continues to be a top consideration when evaluating products that are new in the market. PSE also seeks to leverage existing investments wherever possible when selecting and implementing new technologies. Following a successful evaluation, new technologies can be tested in a lab or piloted *in situ*. Results are documented and reviewed by all impacted teams. As new technologies complete the pilot process, they can be deployed at scale to meet the delivery system needs described above.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 8-167 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,[9] which then creates the full understanding of all the benefits and risks.

[9] / *Investment Decision Optimization Tool which is a software tool called Folio by PwC.*

Figure 8-167: 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; load forecast	Predicted system performance
Electric Predictive Spreadsheet	Electric outage predictive analysis	Electric outage history from SAP	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
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 electric distribution model is a large integrated model of the entire delivery system using a software application (Synergi® Electric) that is updated to reflect new customer loads and system and operational changes. This modeling tool predicts capacity constraints and 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, two 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 that have included ColumbiaGrid, NorthernGrid, 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 J, Regional Transmission Resources, describes regional transmission planning and the role of the Regional Planning Organization (RPO). PSE has been a member of the ColumbiaGrid since 2006, succeeded by NorthernGrid in 2020. The RPO has had substantial responsibilities for transmission planning, reliability and other development services in order to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. PSE is one of eight utilities that coordinate regional planning through the RPO, which has provided 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 electric infrastructure, this includes conductor cross-sectional area, impedance, length, construction type, connecting equipment, transformer equipment, voltage settings, and any DER that is controllable on the system. Next, PSE identifies customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or actual circuit readings. DERs that are not controllable require PSE to consider the load without them operating due to the need for the system to serve as backup. Finally, PSE takes 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. DERs that are on the system that may not be controllable may serve as solutions if and when control and aggregation technologies are added.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 8-168. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission and distribution, as well as for capacity and reliability. A "need" is identified when performance criteria is not met.

Figure 8-168: Performance Criteria for Electric Delivery System

Electric delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (normal winter peak, extreme winter peak) with expected reliability conservation
The nature of service and level of reliability that each type of customer has contracted for (firm or interruptible)
The minimum voltage that must be maintained in the system (no more than 5 percent below standard voltage)
The maximum voltage acceptable in the system (no more than 5 percent above standard voltage)
Thermal limits of equipment used to deliver power to load centers and transmission customers (per PSE Transmission and Distribution Planning Guidelines)
The interconnectivity with other utility systems and resulting requirements, including compliance with NERC planning standards (100 percent compliance) and all required planning scenarios and sensitivities.
The historical or future reliability performance that may be unacceptable or beyond benchmarks which may be caused by aging infrastructure, vegetation, third party damage, equipment condition, or animal interference.
The ability to remove equipment from service for maintenance and provide flexibility for outage restoration.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursing electrification, distributed energy resources dependency at the local circuit level, and deferral of traditional infrastructure network. PSE expects that customers will have higher expectations of reliability and economic impact of outages to be greater, requiring a delivery system with better reliability and resiliency than today. PSE expects delivery system planning margins to increase to account for operating concerns relating to distributed energy resource including behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response have historically incorporated outputs generically, but these assumptions while appropriate for resource planning may not be appropriate for circuit level decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE 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.

Solutions Assessment and Criteria

The alternatives available to address delivery system needs including capacity, reliability, aging infrastructure, and operational flexibility are listed below. Each has its own costs, benefits, challenges and risks.

Figure 8-169: Alternatives for Addressing Electric Delivery System

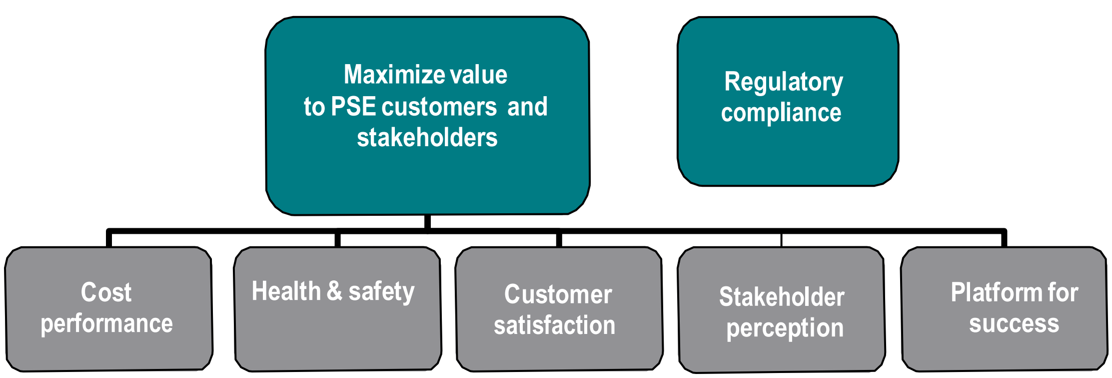
ELECTRIC SYSTEM ALTERNATIVES	
Add energy source	Substation; Distributed energy resource
Strengthen feed to local	New conductor; Replace conductor
Improve existing facility	Substation modification; Expanded right-of-way; Uprate system; Modify automatic switching scheme
Load reduction	Rebalance load; Fuel switching; Battery storage; Natural gas conversion; Conservation/Demand response; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Energy storage can be incorporated in both large-scale and small-scale projects (such as paired with rooftop solar DERs). Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases. Additionally, 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. Finally, in sufficient quantities, distributed energy generated close to load (such as rooftop solar) can also defer investments in traditional delivery system infrastructure and potentially defer the need for additional generation.

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 8-169 as well as consideration of the substation utilization, avoidance of adverse impacts to reliability or operating characteristics, and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the iDOT Tool. iDOT is a project portfolio optimization based on PriceWaterhouseCooper's Folio software that allows us to capture project and program criteria and benefits and score them across thirteen factors associated with 6 categories. These include meeting required compliance with codes and regulations; net present value of the project; improvement to reliability and safety; future possible customer/load additions; deferral or elimination of future costs; customer satisfaction; improved external stakeholder perception; and opportunities for future success gained by increasing system flexibility or 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 8-170: 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 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.

iDOT builds a hierarchy of the value these benefits bring to customers and 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 known permitting or environmental process concerns. Periodically, PSE has reviewed this process and the optimization tool along with the resulting portfolio with WUTC staff.

The iDOT tool also helps PSE examine projects in greater detail than a simple benefit/cost measure. iDOT includes factors such as brand value, health and safety improvements, environmental impact, sustainability, customer value and stakeholder perception. As a result, projects that contribute intangible value receive due consideration in iDOT.

PSE recently expanded the capabilities of iDOT to help us evaluate and compare the relative costs and benefits of wire, non-traditional and hybrid alternatives for the Bainbridge, Seabeck, Lynden and Kitsap pilot projects. New non-traditional benefits mapped to existing iDOT categories include generation capacity deferral entered as a cost reduction. Future iDOT enhancements could incorporate benefits such as battery-produced generation capacity deferral and extended asset life, etc., more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100% clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. As non-wire analysis is pursued, it essentially helps to find the most ideal location for distributed energy resources that are identified through the IRP recommended portfolio, adding value to what has already been captured in that process. Finally, PSE's delivery system planning process will also mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-Wire Alternative Analysis

PSE's planning process has incorporated non-wire alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-wire alternative analysis is a screening process that breaks down of the problem to understand what different pieces may be provided by a distributed energy resource, evaluates the technical distributed energy resource potential, performs an economic analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional wired solution, a full non-wire solution, and potential hybrids across the problem components.

All types of distributed energy resources are considered. With the problem deconstructed to better understand the timing and costs specific portions of the need, a basis analysis tool helps to identify typical distributed energy resources that could solve the problem and whether more detailed analysis is warranted. Leveraging the structure and conservation potential process and tools of the IRP, the analysis may then map distributed energy resource potential to zip codes and estimate hourly load shapes based on specific customer loads to understand the potential further. The analysis may result in a heuristic-based DER potential and cost analysis graphic to help understand what is possible. Understanding the length of investment benefit or lifecycle is important as well such as lifespan of a battery or even demand response programs as home ownership transitions the benefit may change from initial results. The next step of economic analysis determines the costs of alternatives, using traditional cost estimating tools for traditional alternatives, and leveraging IRP cost assumptions and consultant's expertise to understand current and future costs based on developing maturity. This allows for testing optimistic, high benefit value low cost, and pessimistic, low benefit value high cost, considerations through the process. As discussed previously, iDOT can then be used to help evaluate alternatives for benefit to cost and further consider benefits not traditionally quantified. The result of the process is a recommended solution that meets the technical and non-technical solution criteria that then is documented in the solution assessment and the project moves to the project planning phase.

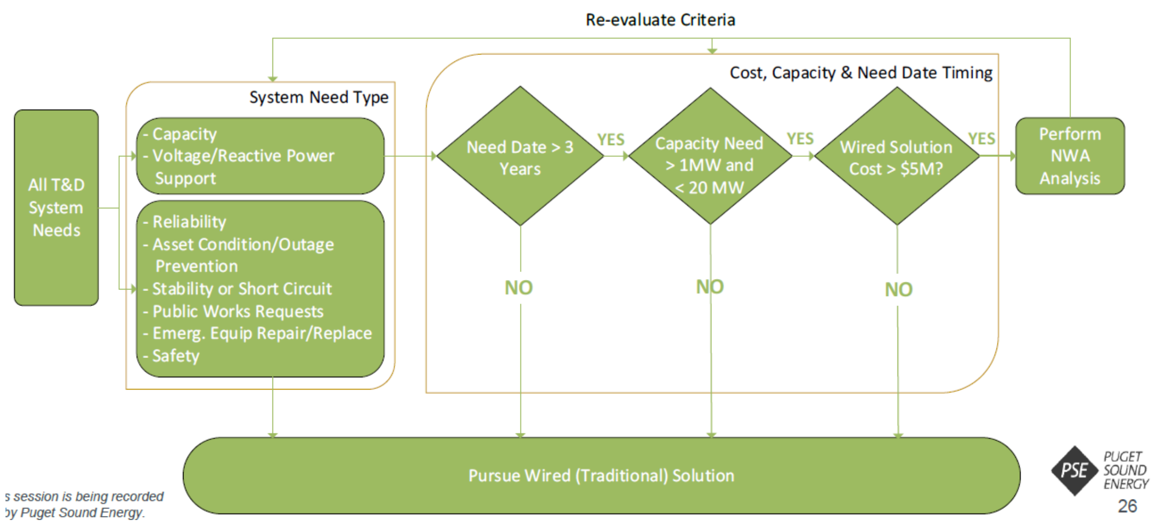
PSE embarked on non-wire analysis in 2018, committing to perform this analysis in four different areas of the system to learn and develop the process. PSE engaged the broad expertise of Navigant and Quanta Technologies to perform and develop its non-wire process and analysis. Non-wire analysis was completed for Bainbridge Island which had a capacity, reliability, aging infrastructure, and operational flexibility need, the entire Kitsap County which had a capacity, aging infrastructure and operational flexibility need, Seabeck which had a smaller circuit capacity and reliability need, and Lynden which had a local capacity, reliability, aging infrastructure, and operational flexibility need. The analysis on these four areas spanned almost 2 years which highlights the complexity of this type of analysis. More detail can be found for each of these area needs in Appendix M.

As a result of this analysis, there are some lessons learned relative to results and where this lengthy complex analysis is most valued. Key findings thus far are that:

- Capacity needs can be effectively met using non-wire alternatives when right sized, maximizing behavior based solutions first. Distributed energy resources that are too large begin to exceed traditional alternatives due to higher cost and long duration of need. Recharging requirements of batteries become as great of a challenge as discharging in some cases.
- Reliability needs are more challenged using non-wire alternatives depending on the length of reliability concern and location of need. Resilience needs, while not discussed much, may be ideal for future distributed energy resource supporting microgrids and locations where critical facilities exist for resilience such as train stations, refueling locations, life support facilities, and commerce.
- Aging infrastructure needs are challenged using non-wire alternatives as they are generally specific locational needs and equipment that if removed cause a wide duration and impact as a result of the connectivity of the grid.
- Non-wires analysis is a time intensive process requiring skilled resources and as a result costs more. Deploying this analysis where the project initiation cost brings value is important to consider in the scheme of the total project costs.
- Non-wire solutions may take time to implement depending on the type of distributed energy resource, PSE's experience, and grid readiness. Solutions such as demand response or behavior based solutions will take time to implement and build reliable confidence to defer traditional solutions. As PSE completes AMI and ADMS implementation and additional grid modernization investments, cost effectiveness of non-wire solutions will increase.

PSE has drafted an initial non-wires screening as a result, Figure 8-171, and through the 2021 IRP began seeking feedback from IRP stakeholders. PSE has performed additional analysis since the initial four areas were identified and these continued studies along with operational experience from previous installations such as PSE's battery in Glacier, Washington as well as on-going pilots will be used to inform this study screening process. This process will be adjusted as technology mature and cost decrease as well.

Figure 8-171: Non-wire Alternative Screening Criteria



Project Planning and Implementation Phase

nce the above process for a particular project and portfolio is completed, reviewed by senior management and approved for funding, the Delivery System Planning initiation phase is complete and the project planning phase begins. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects this may be captured in PSE's SAP system through a notification process or supported from a business case that addresses needs programmatically. The project planning phase involves detailing engineering and technical specifications, pursuing real estate right-of-way needs, planning stakeholder communications and considering potential coordination with other projects in the area. Implementation risks are assessed and mitigation plans are developed as needed. PSE's 10 year plan included in Appendix M reflects projects that are largely in project initiation. Once a project moves to the project planning phase, the need has been established and IRP stakeholder engagement ends while community engagement begins.

Once project need and initiation recommendations are reviewed, annual and two-year work plans are developed for project planning and implementation feasibility. Work plans are coordinated with other internal and external work and resource plans are developed. 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 the total portfolio financial forecast remains within established 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 project lifecycle phase gates and through detailed routing and siting discussions.

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 project planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.

9 Natural 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

1. RESOURCE NEED AND DISCUSSION TOPICS

Resource Need

More than 840,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's natural 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 biggest factor in determining load growth at this time is the increase in customer count.[2]

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2021 IRP Mid (Base) Demand Forecast, the 2021 IRP High Demand Forecast and the 2021 IRP Low Demand Forecast.[3]

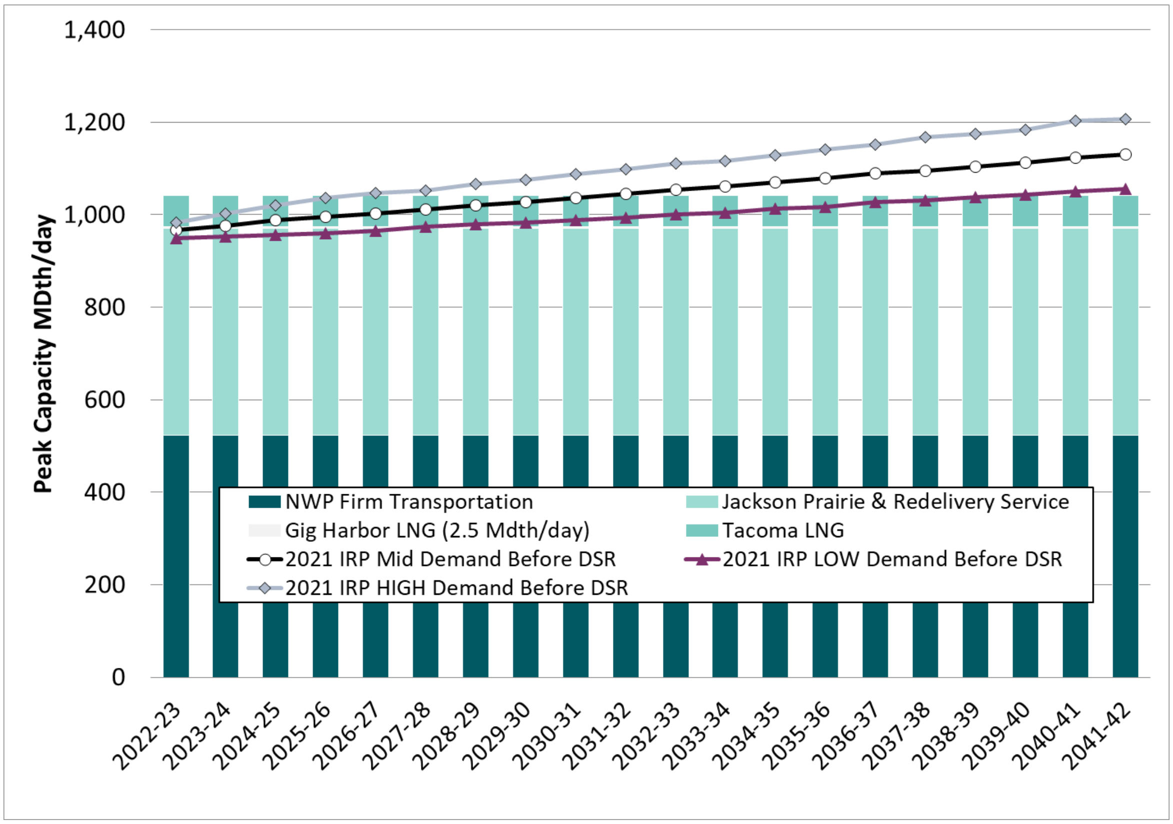
- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need throughout the study period.
- In the Mid Demand Forecast, the first resource need occurs in the winter of 2031-32.
- In the High Demand Forecast, the first resource need occurs immediately.

Figure 9-1 illustrates natural gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 9-2 shows the resource need surplus/deficit for the Mid Demand Forecast.

1 / Heating Degree Days (HDDs) are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD is calculated as 65° less the 13° temperature for the day.
2 / The 2021 IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.
3 / The 2021 IRP demand forecasts are discussed in detail in Chapter 6, Demand Forecasts.

In Figure 9-1, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[4] and the bars represent existing resources for delivering natural gas supply to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[5] The gap between demand and existing resources represents the resource need.

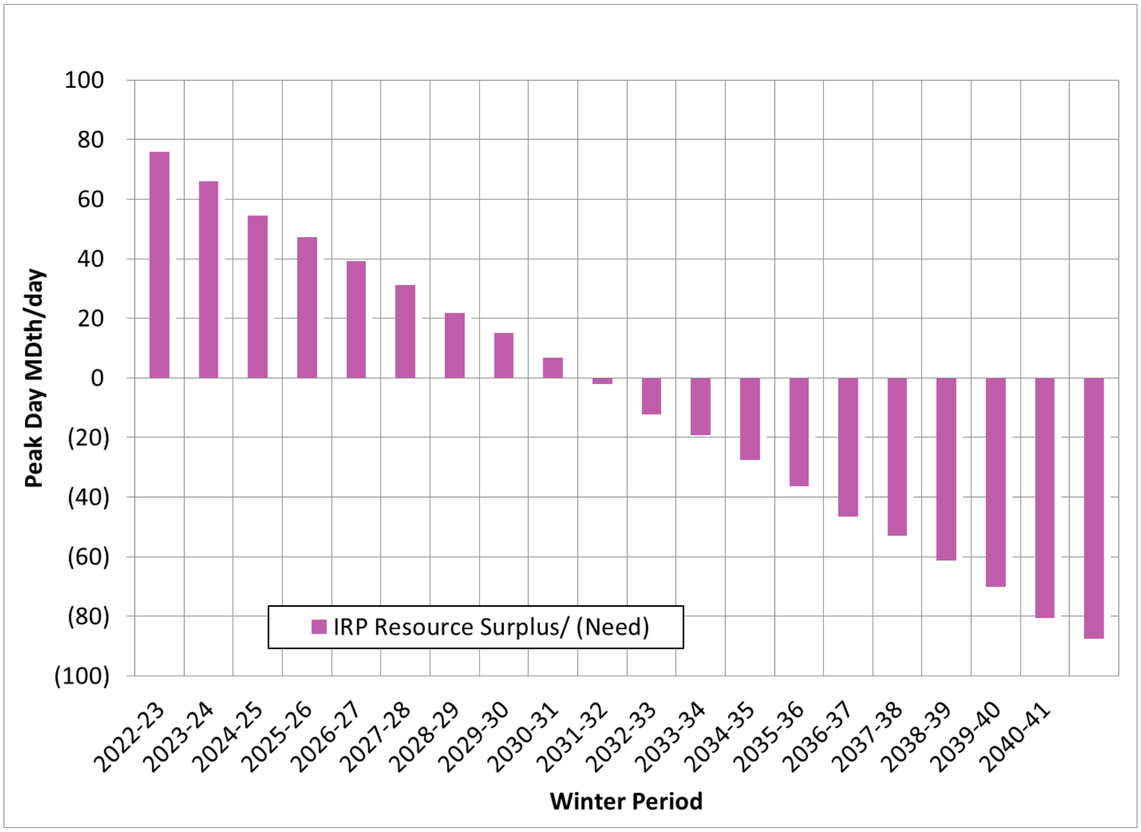
Figure 9-1: Natural Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (meeting need on the coldest day of the year)



4 / 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 additional conservation savings. Therefore the IRP Natural Gas Demand Forecasts include only DSR measures implemented ***before*** *the study period begins in 2022. These charts and tables are labeled "before DSR."*

5 / Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available late in the winter of 2021-22.

Figure 9-2: Natural Gas Sales Peak Resource Need Surplus/Deficit in Mid Demand Forecast before DSR



Discussion Topics

Infrastructure Reliability

Natural gas transportation and distribution systems are not designed to include the type of redundant capacity that electric distribution systems have because the majority of gas infrastructure is located underground where it is largely insulated from the effects of wind and storm damage. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, PSE builds flexibility and resiliency into the system in four ways.

- **A conservative planning standard:** Since PSE's peak day design standard is based on the coldest temperature on record for our service territory, and since this extreme temperature is not often reached and even more rarely sustained, there is some excess capacity in the system on most days.
- **Diverse transport resources:** PSE has built a transport portfolio that intentionally sources natural gas equally from north and south of our service territory to preserve flexibility in the event of supply disruptions. (Approximately 50 percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south.)
- **Natural gas storage:** Including natural gas storage in the portfolio (via Jackson Prairie, Clay Basin, Gig Harbor LNG, and the soon-to-be-completed Tacoma LNG Project) contributes to flexibility and resiliency in several ways. Storage minimizes the need and costs associated with relying on long haul pipelines to deliver gas on cold days; it allows more natural gas to be purchased in the typically less expensive summer season; and it can furnish natural gas supply in the event of a pipeline disruption.
- **Cooperation with regional entities:** Lessons learned from the October 2018 event discussed on the next page were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). Members of the agreement utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest, and they pledge to work together to provide and maintain firm service during emergency conditions and to restore normal service to their customers as quickly as possible after such events occur.

Two incidents illustrate how these strategies work in practice.

A 36-inch pipe on the Westcoast pipeline[6] (Westcoast) between Station 2 and Sumas in central British Columbia (B.C.) ruptured in the early evening of October 9, 2018, shutting off the flow of natural gas from production points in northeast B.C to Sumas for over 30 hours. This resulted in the loss of over 800,000 Dth per day of Sumas supply. Coincidentally, the Jackson Prairie Storage Project was shut down for scheduled maintenance at the time. Coordinating efforts through the Northwest Mutual Assistance Agreement, all the of the natural gas pipelines, utilities, power plant operators and major industrial customers affected worked together to add supply or shed load. Fortis BC, a large downstream utility in southern British Columbia, was able to use some natural gas flowing on its pipeline from Alberta (Southern Crossing), and PSE and other utilities and end-users took steps to reduce natural gas consumption or increase supply from their own on-system storage. These combined efforts prevented a significant loss of pressure in the system, and by 2 p.m. on October 11, 2018 portions of the Westcoast pipeline system were back in service and 38 percent of the normal gas volume from B.C. was flowing. Jackson Prairie personnel worked around the clock to complete the storage facility's planned maintenance ahead of schedule, providing important additional supply to ease the regional situation. Thanks to the combined efforts of Northwest Mutual Assistance participants, the incident lasted less than 48 hours, however, the extensive testing and recertifying required to restore the natural gas flow from B.C. to 100 percent of capacity took over a year. Westcoast was allowed to begin operating its system at 100 percent by mid-November 2019.

In February, 2019, while Westcoast pipeline was still operating significantly below normal levels, the Jackson Prairie Gas Storage Project suffered a major compressor failure that reduced natural gas deliverability by approximately 250,000 Dth per day. The compressor was repaired and back online in less than 30 days, and the net effect of the outage was a reduction in total available storage withdrawals of only 750,000 Dth. Customers experienced no service interruption, but to compensate for the unavailable storage supplies, PSE and other entities that draw natural gas from the storage facility had to purchase additional flowing supply from the market at a time when supply was low and demand, and therefore prices, were high.

These incidents, while quite rare, demonstrate the resilience of the natural gas transportation and storage system in the region. Despite two major failures, no firm residential or commercial customer was without natural gas, nor was there a loss of electrical service, which is increasingly dependent on the natural gas infrastructure. With PSE's current modeling capabilities, it is not possible to model random outages; however, these recent "real-world" experiences demonstrate that the steps taken by PSE to prepare for occasional infrastructure failure have proven successful.

6 / *Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc*

Supply Adequacy

As noted above, PSE intentionally sources natural gas from both north and south of our service territory to preserve flexibility in the event of supply disruptions. Fifty percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south. At this time, we are monitoring developments on the Westcoast pipeline that serves the Sumas market.

PSE holds firm capacity on Westcoast's system for approximately 50 percent of its needs from British Columbia in order to access natural gas supplies in the production basin in northern British Columbia rather than only at the Sumas market. This strategy provides a level of reliability (physical access to natural 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.

When natural gas production in NE B.C. increased substantially due to the shale revolution, a shortage of pipeline capacity leaving the basin developed as producers sought market outlets for the increased production. For the past several years, Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions); so far, the result has been an adequate supply at Sumas in winter months (when the pipeline is in normal operations) and an excess in summer months.

A 2017 Westcoast capacity offering was fully subscribed, and this will drive construction of facilities to provide an additional 105,000 Dth per day of firm capacity on Westcoast and also 94,000 Dth per day of capacity that was previously held back for maintenance and reliability reasons. The new contracts, totaling 199,000 Dth per day, will bring more firm natural gas to the Sumas hub beginning in November 2021

However, between 2024 and 2027, two new large-volume firm industrial loads totaling over 400,000 Dth per day are expected to come online. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand (from both existing and expansion capacity), they will control their own supply and destiny. Much of the firm pipeline capacity that they will use to access their natural gas supply is currently used to provide the adequate and occasionally abundant supplies at the Sumas market hub to other customers. Once the new customers start up their facilities, they will effectively and dramatically reduce the supply available for other customers at Sumas on most days.

PSE is confident that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2021, and that PSE will still be able to compete (on price) to obtain sufficient supplies in peak periods to fill its existing Northwest Pipeline (NWP) capacity, even when the new industrial concerns begin operations. However, PSE is concerned because the increased demand of 400,000 Dth per day is supported by only 199,000 Dth per day of increased capacity, thus placing price pressure on the remaining supplies.

Because there is currently an equilibrium of firm supply and firm demand in peak winter periods and a surplus in summer periods, PSE believes it is not necessary to secure additional firm Westcoast capacity at this time. However, in the future there is the potential for inadequate capacity to bring sufficient supply to Sumas in peak periods. For this reason, the IRP analysis continues to assume that any new long-term NWP capacity from Sumas used to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast that begins at the supply source in NE B.C.

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

Analysis of the natural 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 natural gas resources in a variety of scenarios. Renewal or term extension of existing resources are among the alternatives considered.

Analysis Tools

PSE uses a gas portfolio model (GPM) to analyze natural gas resources for long-term planning and long-term natural 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 I, Natural Gas Analysis Results**, for a more complete description of the SENDOUT gas portfolio model.*

Deterministic Optimization Analysis

PSE developed three natural gas scenarios for this IRP analysis, Mid, High and Low, as shown in Figure 9-3.[7] 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.

Figure 9-3: 2021 IRP Natural Gas Analysis Scenarios

2021 IRP NATURAL GAS ANALYSIS SCENARIOS				
	Scenario Name	**Demand**	**Natural Gas Price**	**CO_2 Price/Regulation**
1	**Mid**	**Mid[1]**	**Mid**	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
2	**Low**	**Low**	**Low**	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
3	**High**	**High**	**High**	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions

NOTE 1. Mid demand corresponds to the 2021 IRP Base Demand Forecast

7 / *Chapter 5, Key Assumptions, describes the scenario inputs in detail.*

PSE also tested five sensitivities in the natural gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect of a single resource, regulation or condition on the portfolio.

Figure 9-4 2021 IRP Natural Gas Portfolio Sensitivities

2019 IRP NATURAL GAS ANALYSIS SENSITIVITIES		
A	**AR5 Upstream Emissions**	The AR5 model is used to model upstream emissions instead of AR4.
B	**6-Year Conservation Ramp Rate**	Energy efficiency measures ramp up over 6 years instead of 10.
C	**Social Discount Rate for DSR**	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
D	**Fuel Switching, Gas to Electric**	Gas-to-electric conversion is accelerated in the PSE service territory.
E	**Temperature Sensitivity on Load**	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
F	**No DSR**	This portfolio will not include any new demand-side resources energy efficiency, distribution efficiency and demand response.

> > > See Appendix I, Natural Gas Analysis Results, *for a detailed presentation of scenario and sensitivity analysis results.*

Natural Gas Peak Day Planning Standard

PSE completed a detailed cost-benefit analysis during the 2005 least cost plan (LCP) that is the basis for the current planning standard. That analysis looked at customers' value of reliability of service with the incremental costs of the resources necessary to provide that reliability at various temperatures. Based on the analysis, PSE determined that it would be appropriate to use the 52 HDD (13ºF) as the peak day planning standard.

PSE has used this planning standard since 2005, including in the 2021 IRP. PSE believes that the planning standard is still appropriate in the current environment for the reasons outlined below.

- The standard is based on reliability and safety. In the natural gas sector when there is an outage, it triggers a safety protocol that requires service technicians to physically shut off the gas at the appliance before gas service is restored and make another visit to turn on pilot gas lights. Due to the work hours involved, the outages can take days to weeks to restore during a time when the weather is at its coldest and space heating is an essential service. The existing standard has prevented outages over the last 15 years, and while during this time we have not seen temperatures that approach the design peak day temperature, there is no certainty that we will not see this temperature in the near future.
- When seen in the context of other regional gas utility planning standards, the PSE natural gas planning standard is in line with industry best practices. PSE's implied temperature criteria derived from its planning standard places it in the 98th percentile for annual peaks from 1950 to 2019 (see Figure 9-5), similar to other PNW utilities (see Figure 9-6).

Figure 9-5: PSE Planning Standard Implied Temperature Criteria

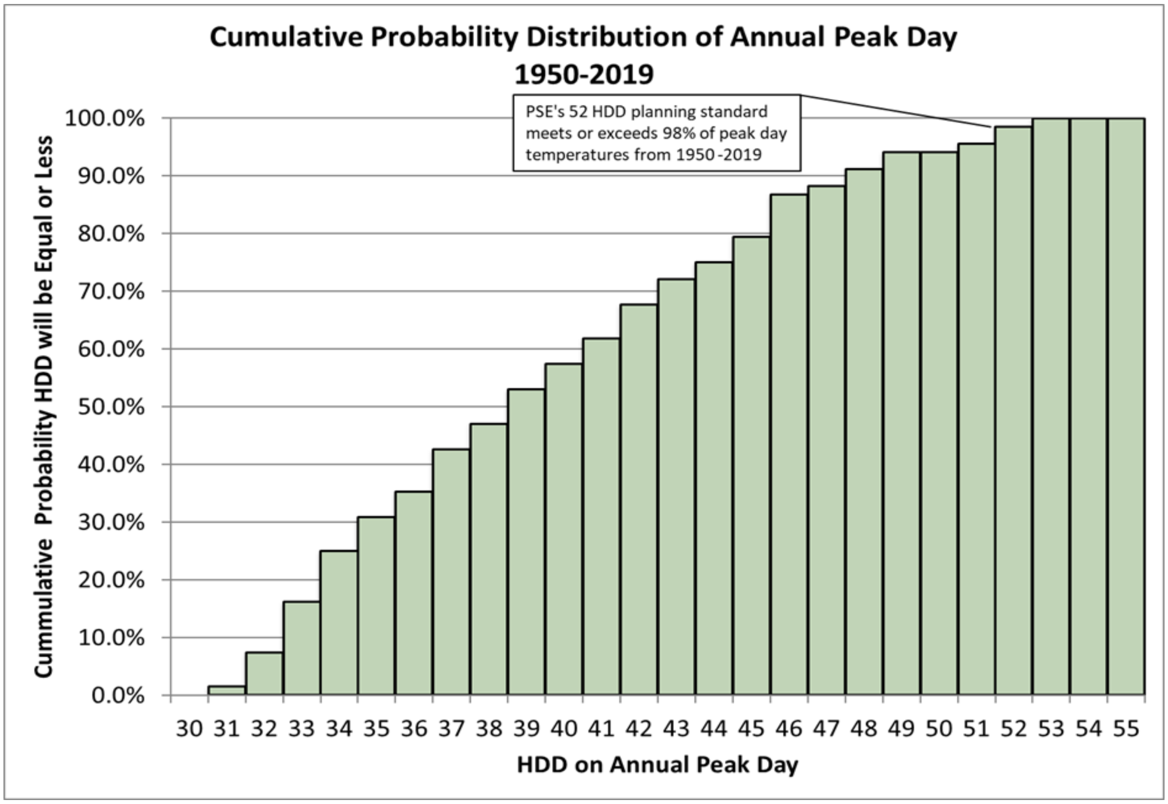


Figure 9-6: Pacific Northwest Natural Gas Utility Planning Standards

PNW Gas Utility	Peak Capacity Design Standard
NW Natural	NW Natural will plan to serve the highest firm sales demand day in any year with 99% certainty: 99th percentile of annual peak days over last 100 years.
Cascade Natural	Coldest day during the past 30 years.
Avista Corp	Adjust the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day.
Fortis NG	1 in 20 years temperature based on annual peak days over last 60 years.
PSE	98th percentile of annual peak days from 1950-2019

Natural gas ignition technology has not changed much in the last 15 years. Penetration of electronic ignition is still very small, so service personnel are still required to relight homes in the event of an outage. The cost of relighting has also increased since the 2005 study due to increased population density and travel times in the region.

The results of the 2021 IRP analysis show that lower demand, which may result from a revised peak day planning standard, will likely not change the resource alternatives needed to serve future loads. Even in the Low Scenario, the natural gas portfolio model selected the same level of cost-effective conservation as the High Scenario. Thus, revising the planning standard would not change the results of the analysis in the 2021 IRP.

Given that the PSE planning standard is in line with peer natural gas utilities, has provided a reliable natural gas system, and will not result in any material change to the resource alternatives chosen in the analysis, PSE believes it is appropriate to use the 52 HDD peak day planning standard in the 2021 IRP. PSE plans to study the impacts of changing the planning standard.

3. EXISTING RESOURCES

Existing natural gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, natural 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 natural gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity

All natural gas delivered to our 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.

- 542,872 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 natural gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity

To transport natural 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 natural gas pipelines for the Pacific Northwest region is provided in Figure 9-7. For the details of PSE's natural gas sales pipeline capacity, see Figure 9-8.

Figure 9-7: Pacific Northwest Regional Natural Gas Pipeline Map

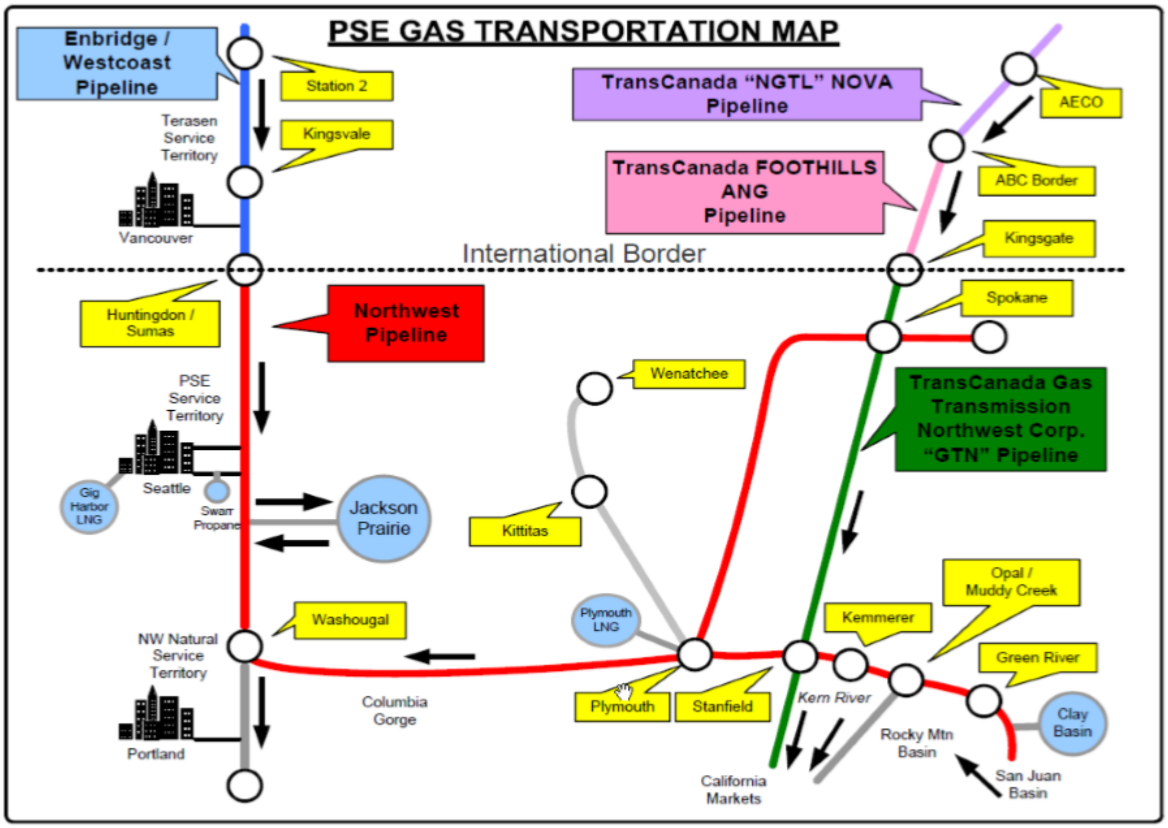


Figure 9-8: Natural Gas Sales - Firm Pipeline Capacity (Dth/day) as of 11/01/2020

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Direct-connect				
NWP/Westcoast Interconnect (Sumas)	1	287,237	135,146	152091
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936
NWP/various in US Rockies & San Juan Basin	1	179,699	52,423	127,276
Total TF-1		**542,872**	**187,569**	**355,303**
NWP/Jackson Prairie Storage Redelivery Service	1,2	447,057	444,184	2,873
Storage Redelivery Service		**447,057**	**444,184**	**2,873**
Total Capacity to City Gate		**989,929**	**631,753**	**358,176**

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Upstream Capacity				
TC-NGTL: from AECO to TC-Foothills Interconnect (A/BC Border)	3	79,744	79,744	-
TC-Foothills: from TC-NGTL to TC-GTN Interconnect (Kingsgate)	3	78,631	78,631	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Spokane)	4	65,392	65,392	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Stanfield)	4,5	11,622	11,622	-
Westcoast: from Station 2 to NWP Interconnect (Sumas)	6,7	135,795	135,795	-
Total Upstream Capacity	**8**	**371,184**	**371,184**	**-**

NOTES
1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
2. 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.
3. Converted to approximate Dth per day from contract stated in gigajoules per day.
4. TC-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.
5. Capacity can alternatively be used to deliver additional volumes to Spokane.
6. Converted to approximate Dth per day from contract stated in cubic meters per day. Westcoast has adjusted the heat content factor upward to reflect the higher Btu gas now normal on its system. The effect is to allow customers to transport more Btu in the same contractual capacity.
7. The Westcoast contracts contain a right of first refusal upon expiration.
8. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

Transportation Types

TF-1

TF-1 transportation contracts are “firm” contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport natural 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.

Primary Firm, Alternate Firm and Interruptible 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 natural 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. Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point.

ALTERNATE FIRM CAPACITY occurs when 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. This “alternate firm capacity” can be very reliable if the contract is used to flow natural gas within the primary path; that is, in the contractual direction to or from the primary delivery or receipt point. Alternate firm is much less reliable or predictable if used to flow natural gas in the opposite direction or “out of path.” While “out of path” alternate firm capacity has higher rights than non-firm, interruptible capacity, it is not considered reliable in most circumstances.

INTERRUPTIBLE CAPACITY on a fully contracted pipeline can become available if a firm shipper does not fully utilize 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 rate for interruptible capacity is negotiable and typically billed as a variable charge. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport natural gas on an alternate basis, outside of their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner “within path” or “out of path,” along with the ability to create “segmented release” capacity, has resulted in very low non-firm, interruptible volumes on the NWP system.

When capacity is not needed to serve natural gas customers on a given day, PSE may use its firm capacity to transport natural gas from a low-priced basin to a higher-priced location and resell the gas to third parties to recoup a portion of demand charges. When PSE has a surplus of firm capacity and market conditions make such transactions favorable for customers, PSE may release capacity into the capacity release market. The company may also access additional firm capacity from the capacity release market on a temporary or permanent basis when it is available and competitive with other alternatives.

Interruptible service plays a limited role in PSE’s resource portfolio because of the flexibility of the company’s firm contracts and because it cannot be relied on to meet peak demand.

Existing Storage Resources

Natural gas storage capacity is a significant component of PSE’s natural 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 natural 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 natural gas during the lower-demand summer season, generally at lower prices, for use during the high-demand winter season.
- Combining storage capacity with firm storage redelivery service transportation allows PSE to contract for less of the more expensive year-round pipeline capacity.
- PSE also uses storage to balance city gate gas receipts from natural gas marketers with the actual loads of our natural 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 that is designed to deliver large quantities of natural gas over a relatively short period of time. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long natural gas supply. Figure 9-9 presents details about storage capacity.

Figure 9-9: Natural Gas Sales Storage Resources[1] as of 11/1/2020

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie – PSE Owned	398,667	147,333	8,528,000	N/A
Jackson Prairie – PSE Owned [2]	(50,000)	(18,500)	(500,000)	2023
Net JP Owned	**348,667**	**128,833**	**8,028,000**	
Jackson Prairie – NWP SGS-2F [3]	48,390	20,404	1,181,021	2023
Net Jackson Prairie	**397,057** [5]	**149,237**	**9,209,021**	
Clay Basin [4]	107,356	53,678	12,882,750	2023
Net Clay Basin	**107,356**	**53,678**	**12,882,750**	
Total	**504,413** [6]	**202,915**	**22,091,771**	

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 to PSE's electric generation portfolio (at market-based price) from PSE natural gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve natural gas sales customers.
3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
4. PSE expects to renew the Clay Basin storage agreements.
5. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio for a total of 447,057 Dth/day.
6. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio.

Jackson Prairie Storage

As shown in Figure 9-9, PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which PSE operates under FERC authorization. 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 natural 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 storage capacity through an SGS-2F storage service contract with NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. 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 natural 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 natural 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.

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. Natural 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 natural 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 natural 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 9-10: Natural 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]	30,000	16,680	128,440	On-system	Nov. 2024+
Tacoma LNG [3]	69,300	2,100	538,000	On-system	Mar. 2021
TOTAL	**101,800**	**21,280**	**676,940**		

NOTES
1. Swarr is currently out of service pending upgrades to reliability, safety and compliance systems. It may be considered in resource acquisition analysis for an in-service date of November 2024 or later.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons per minute, it takes 7.7 days to refill, or 16,680 Dth per day.
3. Planned in-service date is Mar. 1, 2021. Withdrawal (vaporization) capacity will rise in the future when the distribution system is upgraded. Such a distribution system upgrade – allowing an increase of 16,000 Dth per day in LNG vaporization – is considered as a potential new resource in this IRP.

Gig Harbor LNG

Located in the Gig Harbor area of the Kitsap Peninsula, 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 natural 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 natural 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 in Combination #7 – Swarr LP-Air Upgrade, and is assumed to be available on three years' notice as early as the 2023/24 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 natural 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 natural gas customers. This LNG peak-shaving facility is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2021 IRP assumes the project is put into service late in the 2020-21 heating season, providing 69 MDth per day of capacity – 50 MDth per day of vaporization and 19 MDth per day of recalled natural gas supply. The full 85 MDth per day of capacity will become available when additional upgrades to the natural gas distribution system allow vaporization of an additional 16 MDth per day; this additional capacity is assumed to be available as a new resource on three years' notice beginning in the 2024/25 heating season.

Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to natural 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 natural 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. PSE's pipeline capacity on NWP currently provides for 50 percent of our flowing natural gas supplies to be delivered from north of our service territory and the remaining 50 percent from south of our service territory.

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, operational challenges or high local demands. This separation cycle can last several years, but is often 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 transportation costs and forecasted demand increases. The long-term supply pricing scenarios used in this analysis were provided by Wood-Mackenzie, whose North American supply/demand model considers the non-synchronized cyclical nature of growth in production, demand and infrastructure development to forecast monthly pricing in the supply basins accessed by PSE pipeline capacity.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal, Clay Basin and Blanco. 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 (TC-NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (TC-GTN) pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Natural 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) 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. Daily positions are balanced using storage from Jackson Prairie, Clay Basin, day-ahead purchases and off-system sales transactions; intra-day positions are balanced using Jackson Prairie. PSE monitors natural gas markets continuously to identify trends and opportunities to fine-tune our contracting, purchasing and storage strategies.

Existing Demand-side Resources

PSE has provided demand-side resources to our customers since 1993.[8] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[9] Through 1998, the programs primarily served residential and low-income customers; in 1999, they were expanded to include commercial and industrial customer facilities. The majority of natural gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

Figure 9-11 shows that energy efficiency measures installed through 2019 have saved a cumulative total of over 5.4 million Dth, which represents a reduction in CO_2 emissions of approximately 324,000 metric tons – more than half of this amount has been achieved since 2010. Savings per year have mostly ranged from 3 to 5 million therms, peaking at just over 6.3 million therms in 2013.

Energy savings targets and the programs to achieve those targets are established every two years. The 2018-2019 biennial program period concluded at the end of 2019. The current program cycle runs from January 1, 2020 through December 31, 2021 and has a two-year energy savings target of approximately 8 million therms. 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.

PSE spent over $17.5 million for natural gas conservation programs in 2019 (the most recent complete program year) compared to $3.2 million in 2005. Spending over that period increased more than 35 percent annually. The low cost of natural gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. PSE is collaborating with regional efforts to find creative ways to make delivery and marketing of natural gas efficiency programs more cost-effective, and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

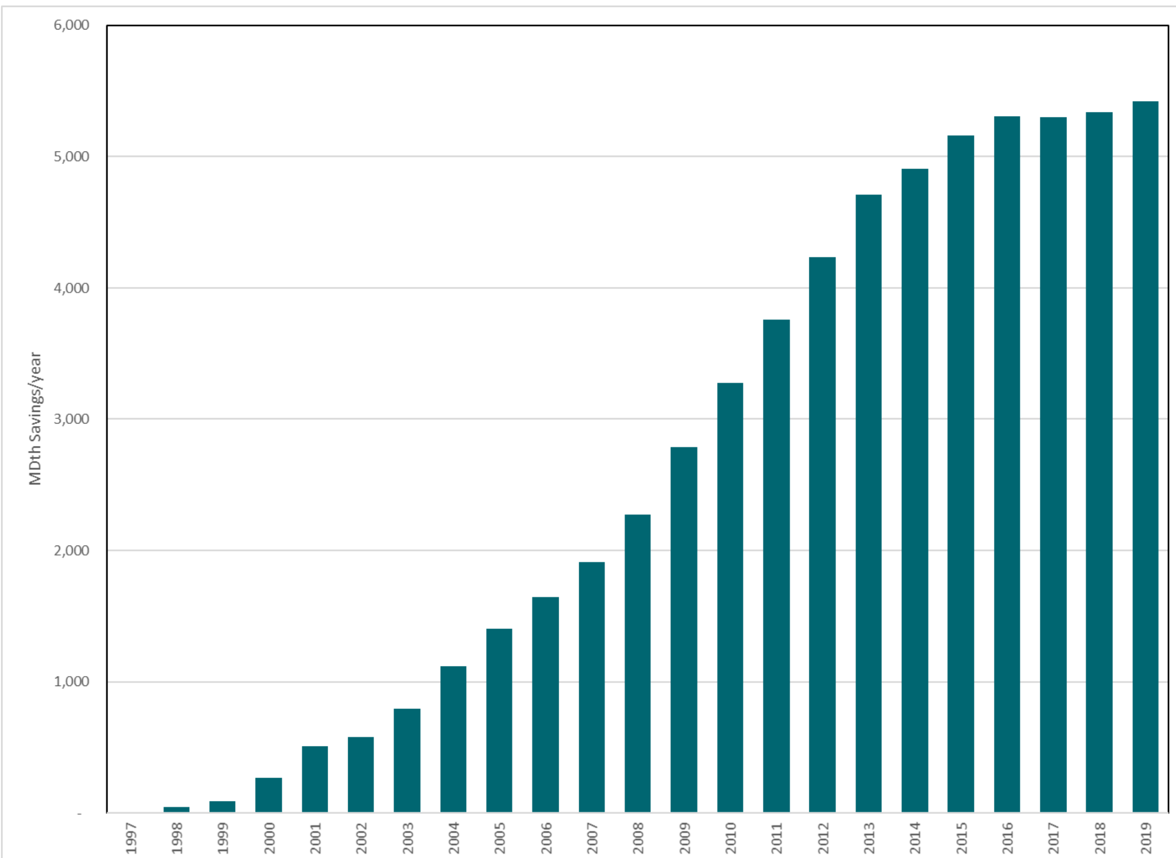
Figure 9-11 summarizes energy savings and costs for 2018 through 2021.

8 / Demand-side resources, also called conservation, contribute to meeting resource need by reducing demand.
9 / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 9-11: Natural Gas Sales Energy Efficiency Program Summary, 2018 – 2021
Total Savings and Costs

Program Year	Actual Savings (MDth)	Actual Cost ($ millions)	Target Savings (MDth)	Budget ($ millions)
2018	377.1	15.8	327	15.3
2019	322.8	17.7	314.7	15.9
2020-21			795.3	34.5

Figure 9-12: Cumulative Natural Gas Sales Energy Savings from DSR, 1997 – 2019



4. RESOURCE ALTERNATIVES

The natural 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 natural gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and natural 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 analysis purposes. These combinations are discussed below and illustrated in Figure 9-13. Note that demand-side resources 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, also known as Nova Inventory Transfer (NIT)
- LP-Air: liquid propane-air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP: Williams Northwest Pipeline, LLC pipeline
- TC-Foothills: TransCanada-Foothills BC (Zone 8) pipeline
- TC-GTN: TransCanada-Gas Transmission-Northwest pipeline
- TC-NGTL: TransCanada-NOVA Gas Transmission Ltd. pipeline
- Westcoast pipeline: Westcoast Energy Inc. pipeline

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2023, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Natural 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 prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that might be available to be contracted to meet PSE needs from November 2022 to October 2025 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to 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 to begin no earlier than November 2025. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) natural 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. As a major greenfield project, this resource option is dependent on significant additional volume being contracted by other parties.

Combination # 3 – Cross Cascades – NWP from AECO

This option provides for deliveries to PSE via a prospective upgrade of NWP's system from Stanfield, Ore. to contracted points on NWP in the I-5 corridor. Availability is estimated no earlier than November 2025. The increased natural gas supply would come from Alberta (AECO hub) via new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield, Ore. Final delivery from Stanfield to PSE would be via the upgraded NWP facilities across the Columbia gorge and then northbound to PSE gate stations. Since the majority of this expansion route uses existing pipeline right-of-way, permitting this project would likely be less complicated. Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

This option involves PSE leasing storage capacity from NW Natural Gas after an expansion of the Mist storage facility. Pipeline capacity from Mist, located in the Portland area, would be required for delivery of natural gas to PSE's service territory, and the expansion of NWP pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracted by other parties. Mist expansion and a NWP southbound expansion – which would facilitate a lower-cost northbound storage redelivery contract – are not expected to be available until at least November 2025.

Combination # 5 – Plymouth LNG with Firm Delivery

This option includes 70.5 MDth per day firm Plymouth LNG service and 15 MDth per day firm NWP pipeline capacity from the Plymouth LNG plant to PSE. Currently, PSE's electric power generation portfolio holds this resource, which may be available for renewal for periods beyond April 2023. While this is a valuable resource for the power generation portfolio, it may be a better fit in the natural gas sales portfolio.

Combination # 6 – LNG-related Distribution Upgrade

This combination assumes completion of the LNG peak-shaving facility, providing 69 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, which would allow an additional 16 MDth per day of vaporized LNG to reach more customers. In effect, this would increase overall delivered supply to PSE customers, since natural gas otherwise destined for the Tacoma system would be displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

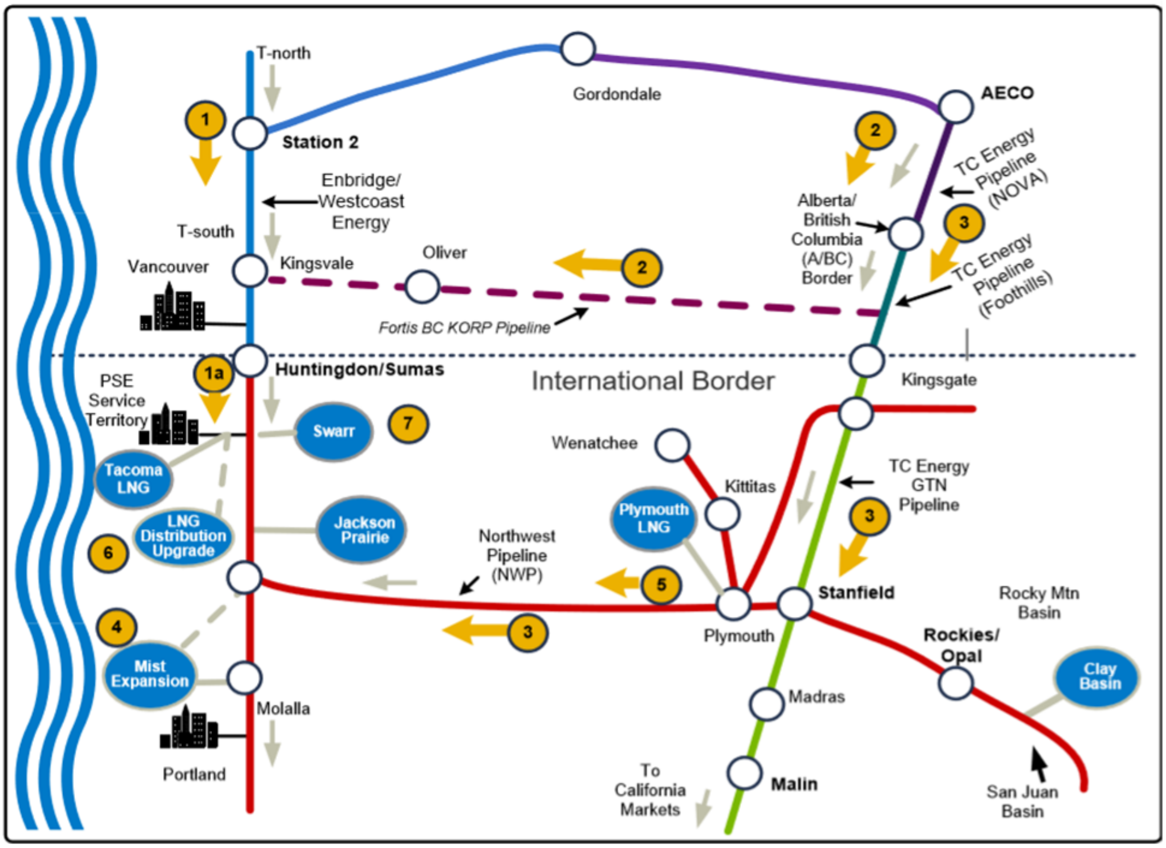
Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility discussed above. The 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, and could be available on three years' notice as early as winter 2024-25.

NOTE: Combinations 2, and 4 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the natural gas sales resource alternatives is depicted in Figure 9-13 below.

Figure 9-13: PSE Natural 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 9-14 below.

Figure 9-14: Direct-connect Pipeline Alternatives Analyzed

Direct-connect Pipeline Alternatives	Description
NWP - Sumas to PSE city gate *(from Combinations 1 & 2)*	Expansions considered in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2025.
NWP – Portland area to PSE city gate *(from Combination 4)*	Expansion considered in conjunction with storage expansion alternatives (Mist storage capacity) assumed available after November 2025.

Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying natural 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 (Westcoast Energy's B.C. pipeline), which allows PSE to purchase natural gas at Station 2 rather than Sumas and take advantage of greater supply diversity availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase natural gas directly from suppliers at the very liquid AECO/NIT trading hub and transport it to the existing interconnect with NWP and its proposed Cross-Cascades upgrade 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.

Figure 9-15: 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 natural gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Madras or Stanfield) *(from Combination 3)*	Acquisition of new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT natural gas to Madras for connection to the TC Cross-Cascades project and a separate northbound upgrade of NWP or to Stanfield for delivery to PSE city gate via the proposed NWP Cross Cascades upgrade. Assumed availability no earlier than November 2025.
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. Available no earlier than November 2025.

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.

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 2025. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2025, 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.

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 natural gas otherwise destined for the Tacoma system is displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

Swarr

The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated while PSE is in the preliminary stages of designing the upgrade to 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 three years' notice for the 2024-25 heating season or beyond.

Figure 9-16: Natural Gas Storage Alternatives Analyzed

Storage Alternatives	Description
Expansion of Mist Storage Facility *(Combination 5)*	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 2025-26 heating season. (Requires incremental pipeline capacity.)
Distribution upgrade allowing greater utilization of Tacoma LNG *(Combination 7)*	Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG peak-shaving beginning the 2024-25 heating season.
Swarr LP-Air Facility Upgrade *(Combination 8)*	Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2024-25 heating season.
Plymouth LNG contract with NWP firm transportation *(Combination 6)*	Considers acquisition of an existing Plymouth LNG contract and associated firm transportation for 15 MDth/day, beginning April 2023.

Natural Gas Supply Alternatives

Conventional Natural Gas

As described earlier, natural 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 natural gas supplies will be available to support pipeline expansion from northern British Columbia via Westcoast or TC-NGTL,TC-Foothills and TC-GTN or from the Rockies basin via NWP.

Renewable Natural Gas (RNG)

Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

HB 1257 passed the Washington State legislature and became effective in July, 2019; it was also incorporated in the WUTC RNG Policy Statement issued in December 2020. PSE is working with the WUTC and other stakeholders to develop guidelines for implementation, PSE conducted a RFI (Request for Information) to determine the availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in 2021. RNG supply not utilized in PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. However, because of RNG's significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for generic analysis. The benefits of RNG are measured in terms of CO_2e reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Avoided pipeline charges realized by connecting acquired RNG directly to the PSE system will be considered, but are not significant relative to the cost of the RNG commodity. Contract RNG purchases present known costs, however, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, PSE is not prepared to discuss specific potential RNG projects in a public environment. Individual projects will be analyzed and documented as PSE pursues additional supplies.

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's natural gas system, annually. PSE is planning significant further investments in cost-effective RNG, and PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future voluntary RNG program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. In order to meet the expectations in the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

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. To be consistent with electric measures, the achievability factors for all natural gas retrofit measures was assumed to be 85 percent. Similar to electric measures, all natural gas measures receive a 10 percent conservation credit 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 lower cost bundles were further divided into smaller segments to ensure that some measures included in a larger, marginal bundle don’t get missed.[10] 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 9-17 shows the price bundles and corresponding savings volumes in achievable technical potential that were developed for this IRP. The bundles are shown in dollars per therm and the savings for each bundles shown in 2031 and 2041 are in thousand dekatherms per year

10 / The $4.5 to $5.5 per Dth and the $5.5 to $7.0 per Dth bundles were divided into four bundles: $4.5 to $5.0, $5.0 to $5.5, $5.5 to $6.2 and $6.2 to $7.0. The narrower ranges allow for a more refined selection of conservation on the supply curve.

(MDth/year). These savings were developed using PSE's weighted average cost of capital (WACC) as the discount rate.

PSE currently seeks to acquire as much cost-effective natural gas demand-side resources as quickly as possible. The acquisition rate or "ramp rate" of natural gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures assume a 10-year ramp rate; in other words, they are acquired during the first 10 years of the study period.

Figure 9-17: Natural Gas DSR Cost Bundles and Savings Volumes (MDth/year)

	DSR Savings Volume (MDth/year)	
	2031	2041
Codes & Standards	725	1,446
Bundle 1: <$0.22	2,393	4,356
Bundle 2: $0.22 to$0.30	2,673	4,672
Bundle 3: $0.30 to $0.45	3,902	7,764
Bundle 4: $0.45 to $0.50	3,932	7,802
Bundle 5: $0.50 to $0.55	3,988	7,898
Bundle 6: $0.55 to $0.62	4,008	7,936
Bundle 7: $0.62 to $0.70	5,112	9,105
Bundle 8: $0.70 to $0.85	5,419	10,093
Bundle 9: $0.85 to $0.95	5,586	10,286
Bundle 10: $0.95 to $1.20	5,812	11,373
Bundle 11: $1.20 to $1.50	7,621	13,341
Bundle 12: >$1.50	10,421	17,051

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment*, for more detail on the measures, assumptions and methodology used to develop DSR potentials.*

In the final step, the natural 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 9-18 illustrates the methodology described above.

Figure 9-18: General Methodology for Assessing Demand-side Resource Potential

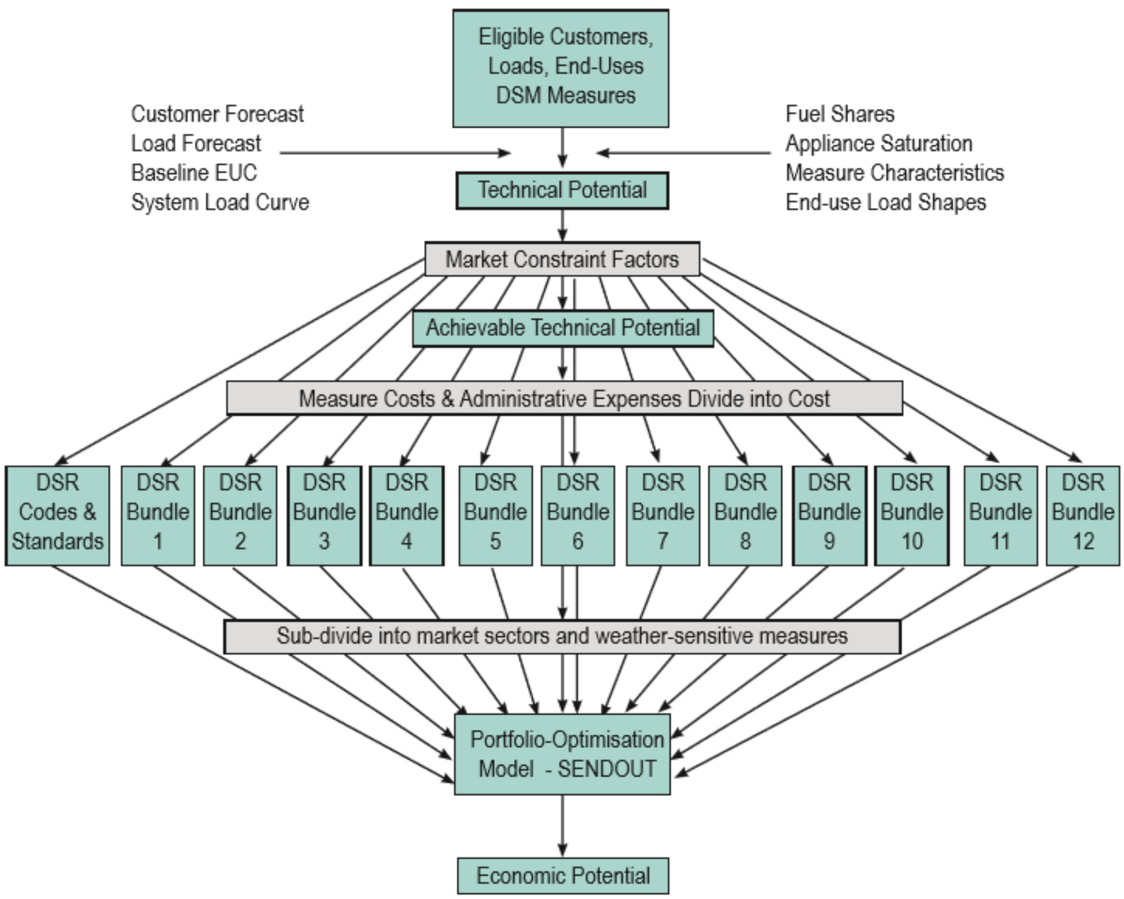


Figure 9-19 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side natural gas resource for a particular scenario.

Figure 9-19: Demand-side Resources – Achievable Technical Potential Bundles

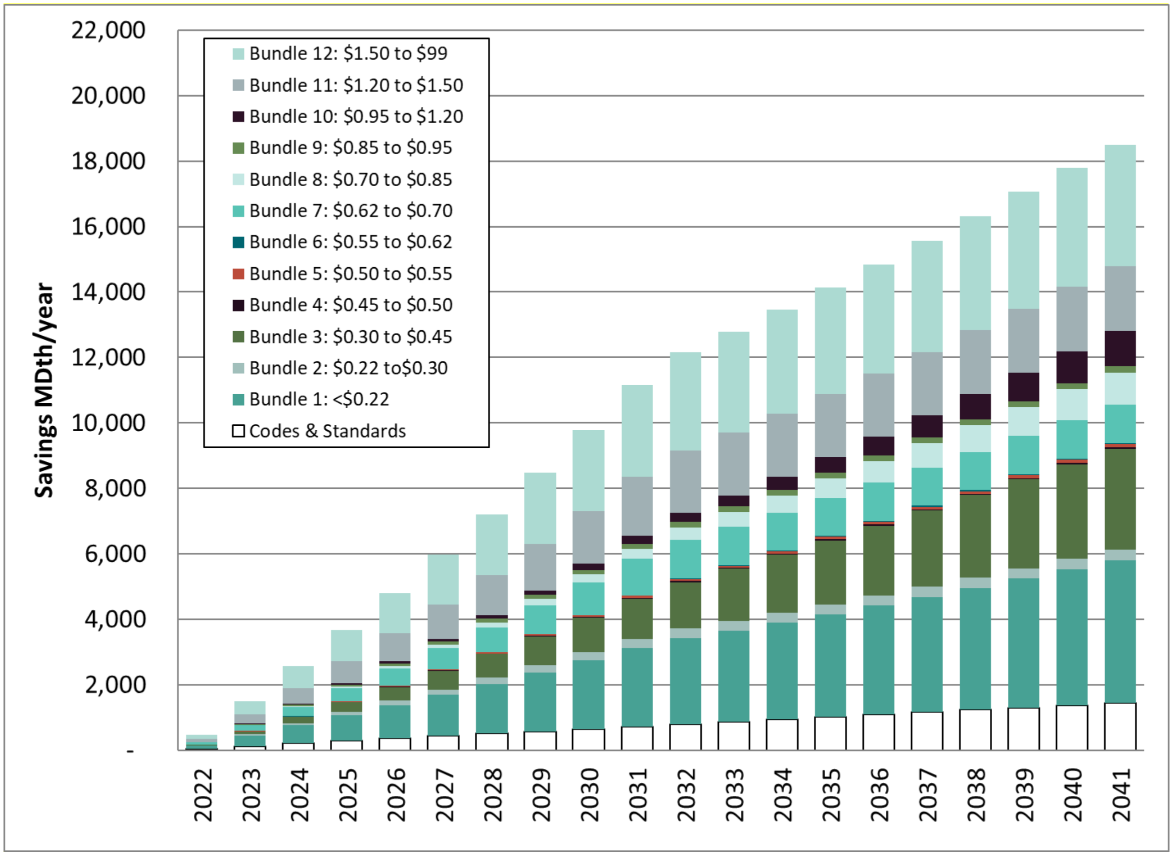
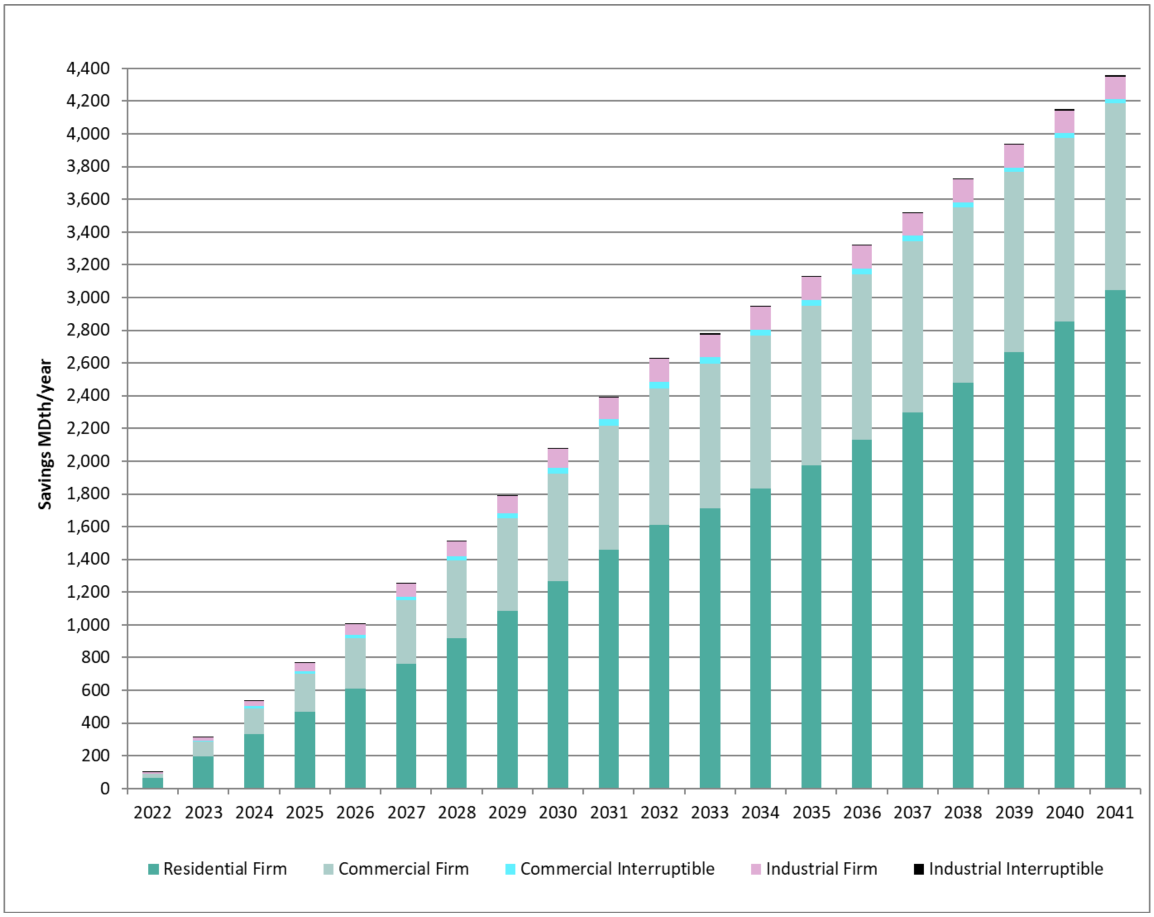


Figure 9-20 shows DSR savings subdivided by customer class. This input format is used in the GPM for all bundles in all the IRP scenarios.

Figure 9-20: Savings Formatted for Portfolio Model Input by Customer Class



5. NATURAL GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical 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 Mid Scenario, the natural gas sales portfolio is short resources beginning in the winter of 2031/32 and each year after that.** The High Scenario also has a deficit starting in 2026/27 and a growing resource shortfall throughout the study, while in the Low Scenario the portfolio is short beginning 2040/41.
2. **Resource needs are primarily met with demand-side resources in the Mid and Low Scenarios.** The gas portfolio model adds the same amount of demand-side resources in both scenarios. In both cases, it added slightly more DSR than is needed to meet the resource need due to the high total natural gas costs resulting from the SCGHG and upstream emissions adders.
3. **The High Scenario has a higher need and is short 165 MDth/day on the peak day in 2041.** The natural gas portfolio model adds the same amount of DSR as in the Mid and Low Scenarios and chooses Plymouth LNG, Swarr and pipeline capacity expansion on Northwest and Westcoast pipelines sourcing natural gas from Station 2 to meet resource need.
4. **Cost-effective DSR is higher in the 2021 IRP.** The cost-effective bundles in all sectors are higher on the supply curve compared to the 2017 IRP. The increase is due to a significant increase in the quantity of new DSR savings in the supply curve and substantially higher natural gas costs. The result is an overall increase in the cost-effective DSR
5. **Cost-effective DSR is the same in all three scenarios.** The total amount of cost-effective DSR chosen in the Mid, Low and High Scenarios did not change. The primary driving factor appears to be the high total natural gas cost, which the DSR helps to offset, thereby reducing portfolio cost.
6. **The Swarr LP-Air upgrade project is cost effective in the High Scenario** and is expected to provide 30 MDth per day of peaking capacity effective November 2037.
7. **The Tacoma area distribution system upgrade project was not needed.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.

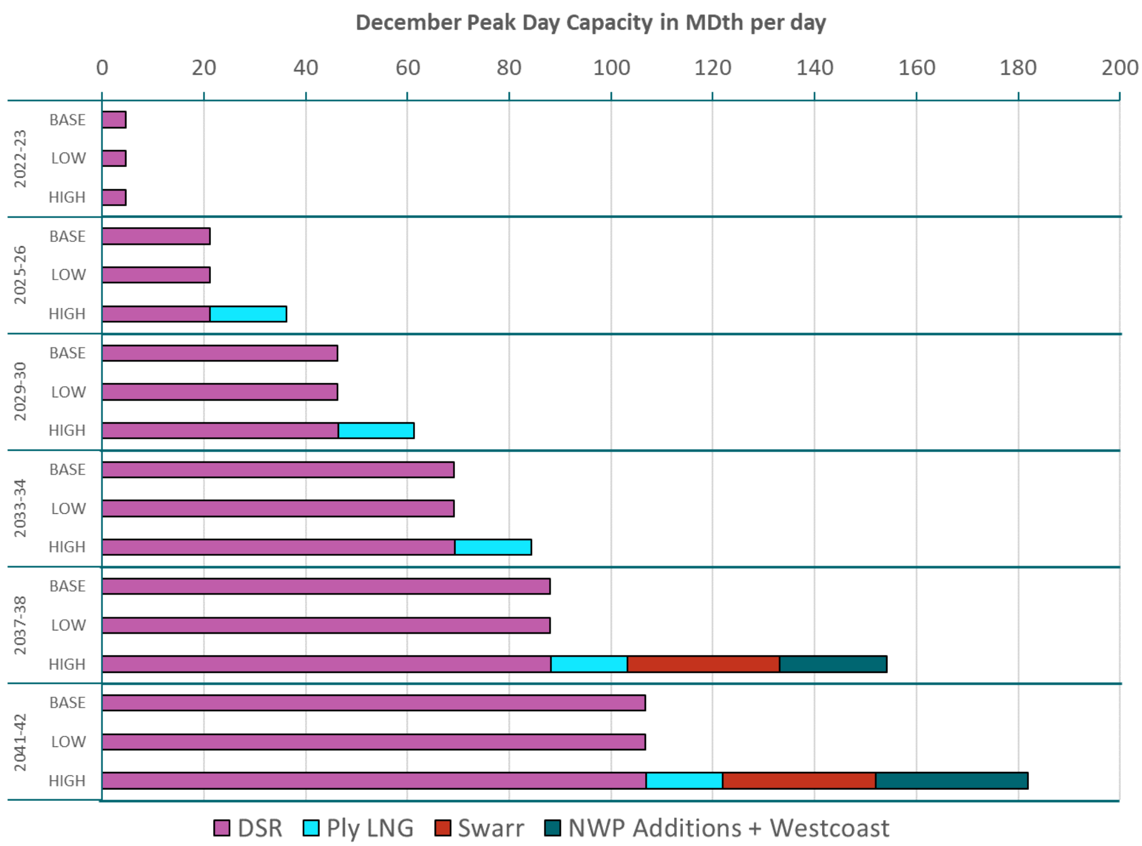
8. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in only the High scenario.** The GPM indicates this pipeline capacity is cost effective starting in 2034/35.
9. **Neither the Cross Cascades TC new pipeline or the Fortis BC KORP project are selected in any scenario.** The resource need is low enough to be satisfied by DSR and thus did not warrant a need for these resources. Additionally, these options present other constraints, such as requiring significant demand by third parties or reliance on other projects and timing outside the control of PSE to become viable.
10. **The Mist Storage project was not selected in any of the Scenarios.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.
11. **The carbon cost assumption was significantly higher in the 2021 IRP compared to the 2017 IRP, and this impacted resource choices.** The levelized cost of carbon adders, which included social cost of greenhouse gases (SCGHG) and upstream emissions, was more than double the levelized natural gas commodity price in all three scenarios. This high cost resulted in greater volumes of demand-side resources being selected in all three scenarios. The high total natural gas cost drove the selection of cost-effective DSR in all three scenarios.
12. **The level of cost-effective DSR found in the deterministic Mid-Low-High Scenarios is a robust result**. In the stochastic analysis, this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly.
13. **Cost-effective DSR reduced both cost and risk in the natural gas portfolio** according to the stochastic analysis.

Natural Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, natural gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by natural 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 the new supply curve and load growth assumptions. Also, the timing of pipeline additions was limited to five-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the three scenarios are illustrated in Figure 9-21 for several winter periods. Combination #1 (NWP plus Westcoast), Combination #5 (Plymouth LNG peaker) and Combination #7 (Swarr LP Plant) are chosen only in High Scenario. The Low and Mid Scenarios both chose only DSR.

Figure 9-21: Natural Gas Resource Additions in 2022/23, 2025/26, 2029/30, 2033/34 and 2041/42 (Peak Capacity – MDth/day)



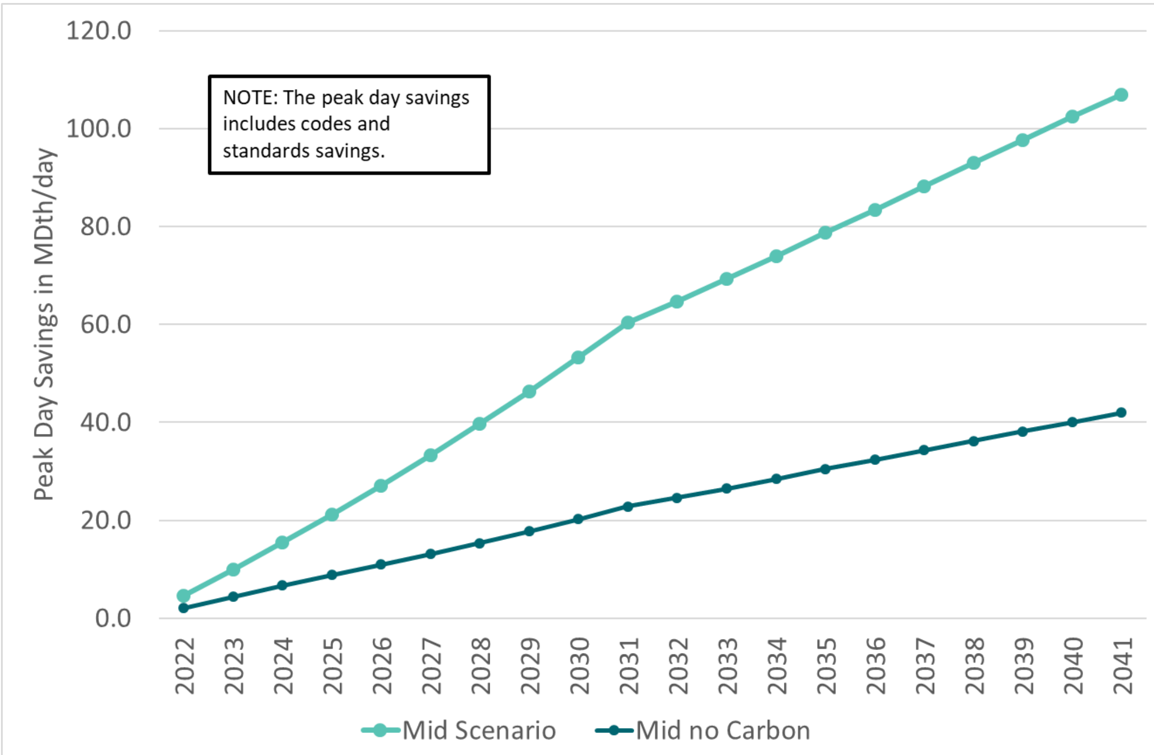
Demand-side Resource Additions

Two categories of demand-side resources are input into 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 natural 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 2017 IRP, the 2021 IRP carbon costs in the Mid Scenario are significantly higher relative to natural gas prices, which is a function of both declining natural gas prices and higher carbon cost assumptions resulting from carbon legislation passed in the state of Washington in 2019. The carbon legislation requires the inclusion of SCGHG and upstream related carbon emissions. Including these two adders in the price of natural gas results in a total natural gas cost that is over three times the cost of the natural gas itself. This total natural gas cost is what is used to make capacity expansion decisions in the GPM, and in these conditions, DSR is preferred in all scenarios since it is a resource that directly offsets the high total natural gas cost and helps to minimize the portfolio cost.

The sensitivity of DSR to carbon prices is illustrated in Figure 9-22. In the Mid Scenario, when including the carbon adders, cost-effective DSR is 107 MDth per day by 2041/42. This amount is actually more than the resource need in 2041/42 of 88 MDth per day, meaning DSR is being over built by about 19 MDth per day. When the Mid Scenario is run with no carbon adders, using only the natural gas cost, the cost-effective DSR drops to 42 MDth per day. In terms of natural gas supply planning, 42 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the IRP Mid Scenario increases conservation. The carbon adders more than double the cost-effective DSR over the 20-year period.

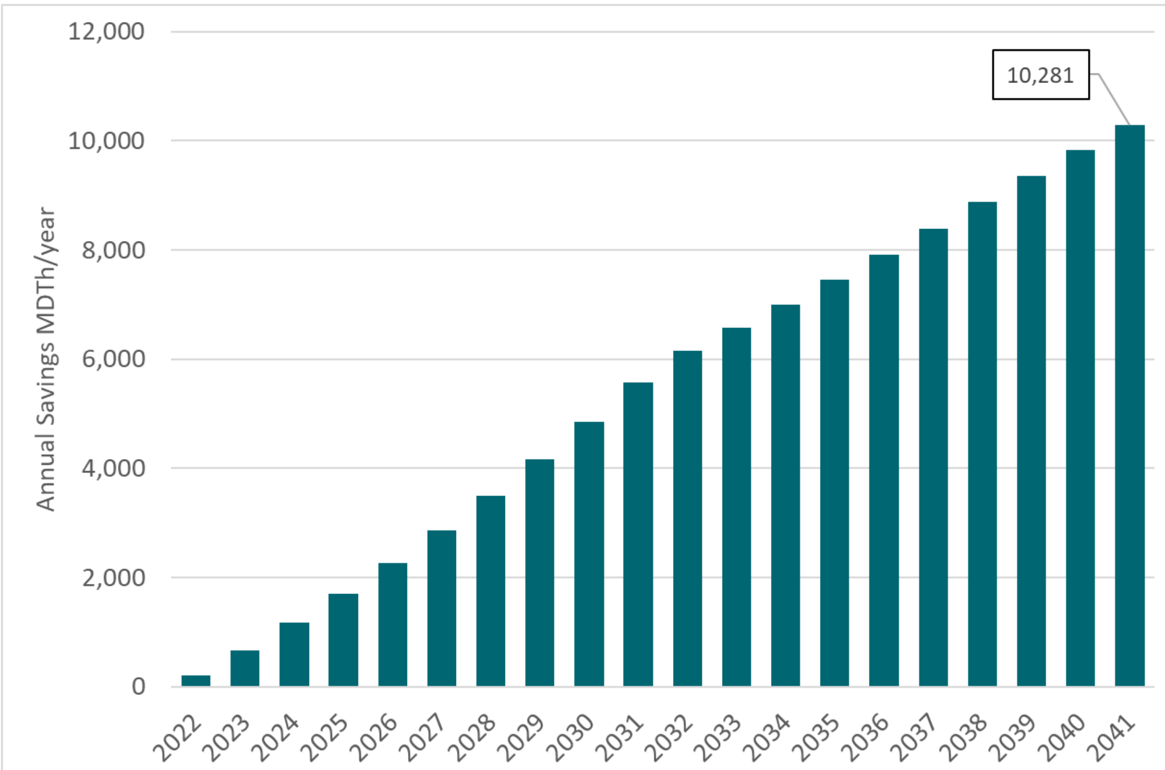
Figure 9-22: Sensitivity of Carbon to Cost-effective Natural Gas Energy Efficiency Savings in the Mid Scenario



DSR is not very sensitive to high avoided costs in the natural gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this resource plan did not vary by scenario.

Energy savings for all three scenarios are shown in Figure 9-23.

Figure 9-23: Cost-Effective Natural Gas Efficiency, Annual Energy Savings for Mid/Low/High Scenario



The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 9-24 and 9-25, below.

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more detail on this analysis.*

Figure 9-24: Natural Gas Sales Cost-effective DSR Bundles by Class and Scenario

Cost-effective Bundles	Mid	Low	High
Residential Firm	9	9	9
Commercial Firm	9	9	9
Commercial Interruptible	6	6	6
Industrial Firm	9	9	9
Industrial Interruptible	9	9	9

Figure 9-25: Natural Gas Sales Cost-effective Annual Savings by Class and Scenario (MDth/year)

Savings (MDth/year)	Mid	Low	High
Residential Firm	7,984	7,984	7,984
Commercial Firm	2,093	2,093	2,093
Commercial Interruptible	39	39	39
Industrial Firm	156	156	156
Industrial Interruptible	8	8	8
Total (MDth per year)	**10,281**	**10,281**	**10,281**

Overall, the economic potential of DSR in the 2021 IRP is higher than in the 2017 natural gas sales Mid Scenario, and higher-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 9-26).

The upward shift in overall savings is due to two factors:

- Higher total natural gas costs that include carbon adders for both end-use and upstream emissions.
- Updates to the measure costs and savings assumptions such that the achievable technical potential was higher and some measures shifted to lower cost effective bundles in the 2021 IRP.

It is notable that the two factors above were a much stronger influence than the following factors, which would have reduced the available DSR under normal circumstances:

- A lower demand forecast in the 2021 IRP than the 2017 IRP
- Four additional years of program implementation will elapse between the 2017 IRP and 2022 when the 2021 IRP study starts, which means that four years of conservation implementation will have reduced the available DSR from the supply curve

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more information on the development of DSR bundles.*

Figure 9-26: Cost-effective Natural Gas Energy Efficiency Savings, 2017 IRP vs 2021 IRP

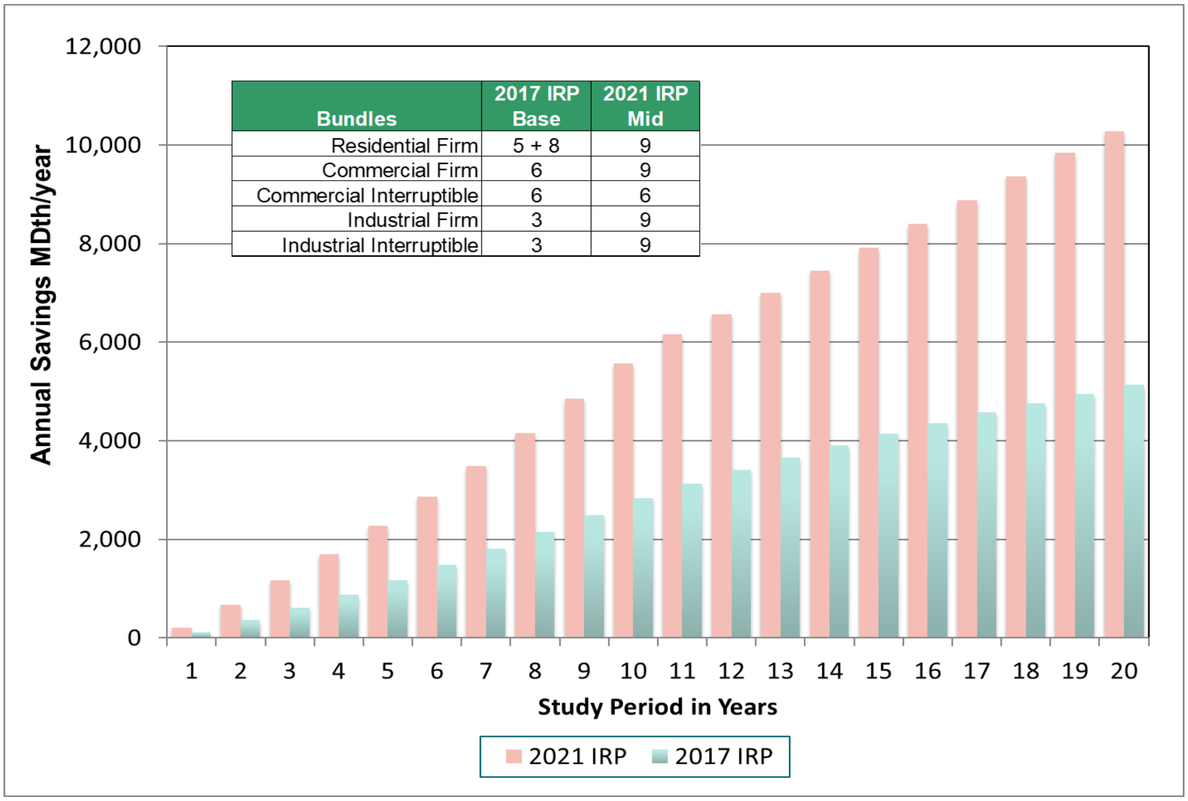


Figure 9-27 compares PSE's energy efficiency accomplishments, current targets and the new range of natural gas efficiency potentials determined by the 2021 IRP. In the short term, the 2021 IRP indicates an economic potential savings of 1,192 MDth for the 2022-2023 period for all three scenarios.[11] These two-year program accomplishments and projections show an upward trend, with the 2021 IRP results indicating that the trend is accelerating due to higher avoided costs and more cost-effective saving measures in the supply curve.

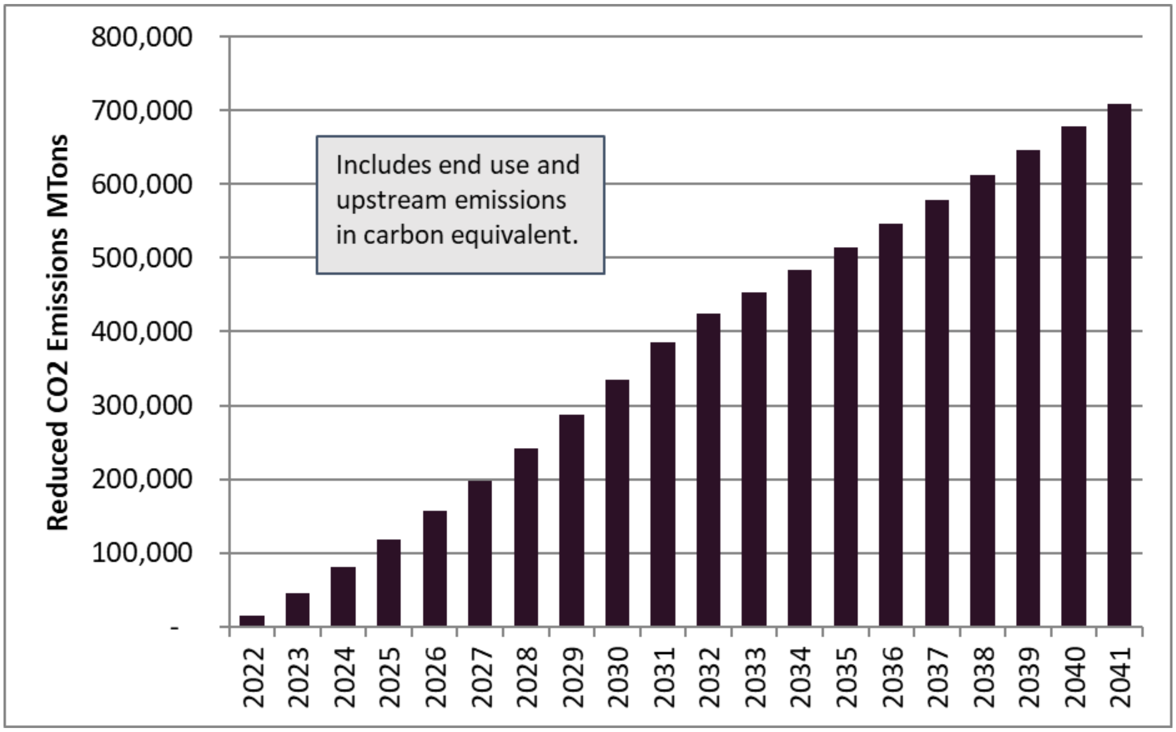
Figure 9-27: Short-term Comparison of Natural Gas Energy Efficiency in MDth

Short-term Comparison of Natural Gas Energy Efficiency	2-year Program Savings (Mdth)
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP Scenarios	1,192

11 / These savings are based on a no-intra year ramping, which is used to set conservation program targets.

Figure 9-28 shows the impact on CO_2 emissions from energy efficiency measures selected in the Mid, Low and High Scenarios.

Figure 9-28: CO_2 Emissions Reduction from Energy Efficiency in Mid, Low and High Scenarios



Peaking Resource Additions

The Swarr LP-Air upgrade project and the Plymouth LNG peaker contract were selected as least cost in only the High Scenario due to the higher resource need created by the higher demand forecast in this scenario.

Pipeline Additions

Pipeline expansion alternatives were made available as early as the 2025/26 winter season, a bit later than the other non-pipeline alternatives were made available. The pipelines were not available earlier due to the lead time needed to develop these resources, but this was not a constraint to the portfolio model. The pipelines were chosen only in the High Scenario, which had a higher resource need due to higher demand. In the High Scenario, the GPM selected 30MDth a day of NWP with Westcoast from Station 2 in the out year.

The other pipeline additions offered in Combinations #2 (KORP) and #3 (Cross Cascades) were not economical in any of the scenarios.

Observation

All of the selected resources (listed here in general order of least cost) – DSR, Plymouth LNG Peaker, Swarr LP-Air, and Northwest + Westcoast pipeline expansion – are within PSE's control (with the exception of the pipeline expansion). The timing of individual projects can be fine-tuned by PSE in response to load growth changes, and none of these projects rely on participation by another contracting party in order to be feasibly implemented.

Complete Picture: Natural Gas Sales Mid Scenario

A complete picture of the Mid Scenario optimal resource portfolio for natural gas sales is presented in graphical and table format in Figures 9-29 and 9-30, respectively.

> > > See Appendix I, Natural Gas Analysis Results, *for additional scenario results.*

Figure 9-29: Natural Gas Sales Mid Scenario Resource Portfolio

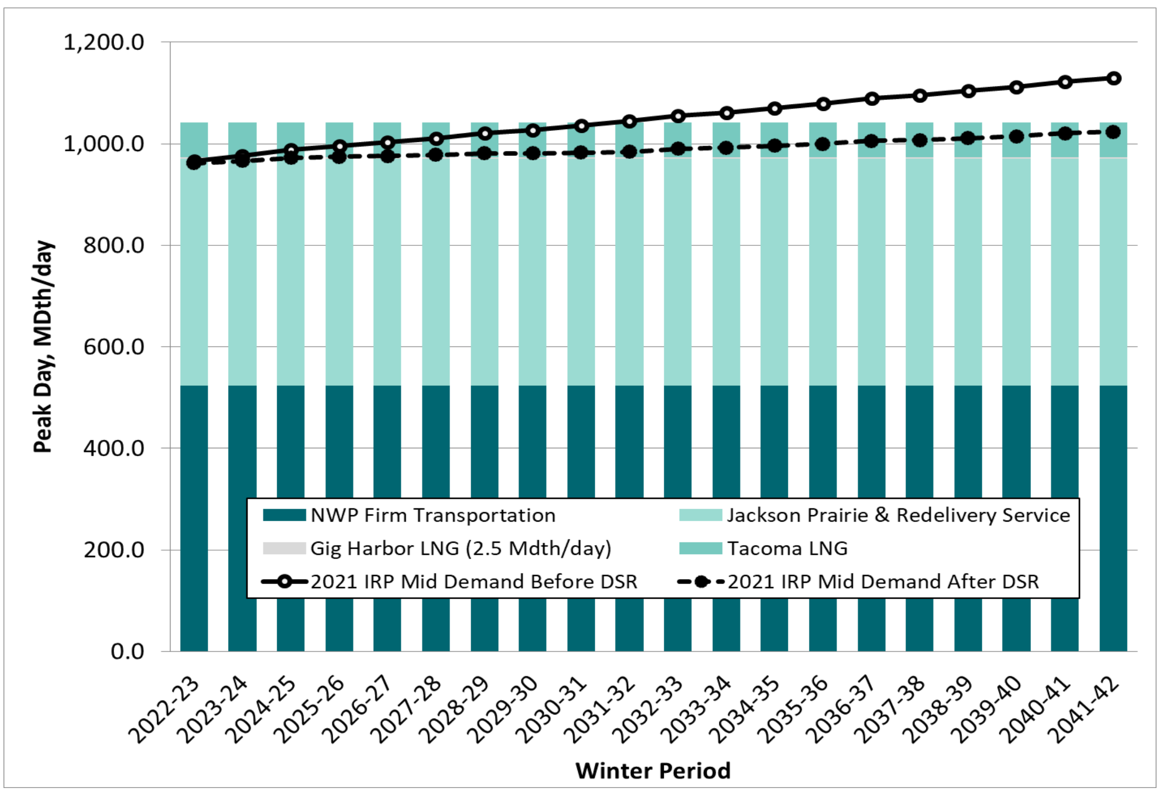


Figure 9-30: Natural Gas Sales Mid Scenario Resource Portfolio (Table)

		Winter Period		
Resource Alternative	Option	2025/26	2030/31	2041/42
NWP Additions + Westcoast	#1	-	-	-
KORP	#2	-	-	-
NWP from AECO	#3	-	-	-
Mist Storage	#4	-	-	-
Ply LNG	#5	-	-	-
LNG Tacoma Distr	#6	-	-	-
Swarr	#7	-	-	-
DSR	DSR	21	53	107
Total in MDth/day		**21**	**53**	**107**

Average Annual Portfolio Cost Comparisons

Figure 9-31 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 Tacoma 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 9-31: Average Portfolio Cost of Natural Gas for Gas Sales Scenarios

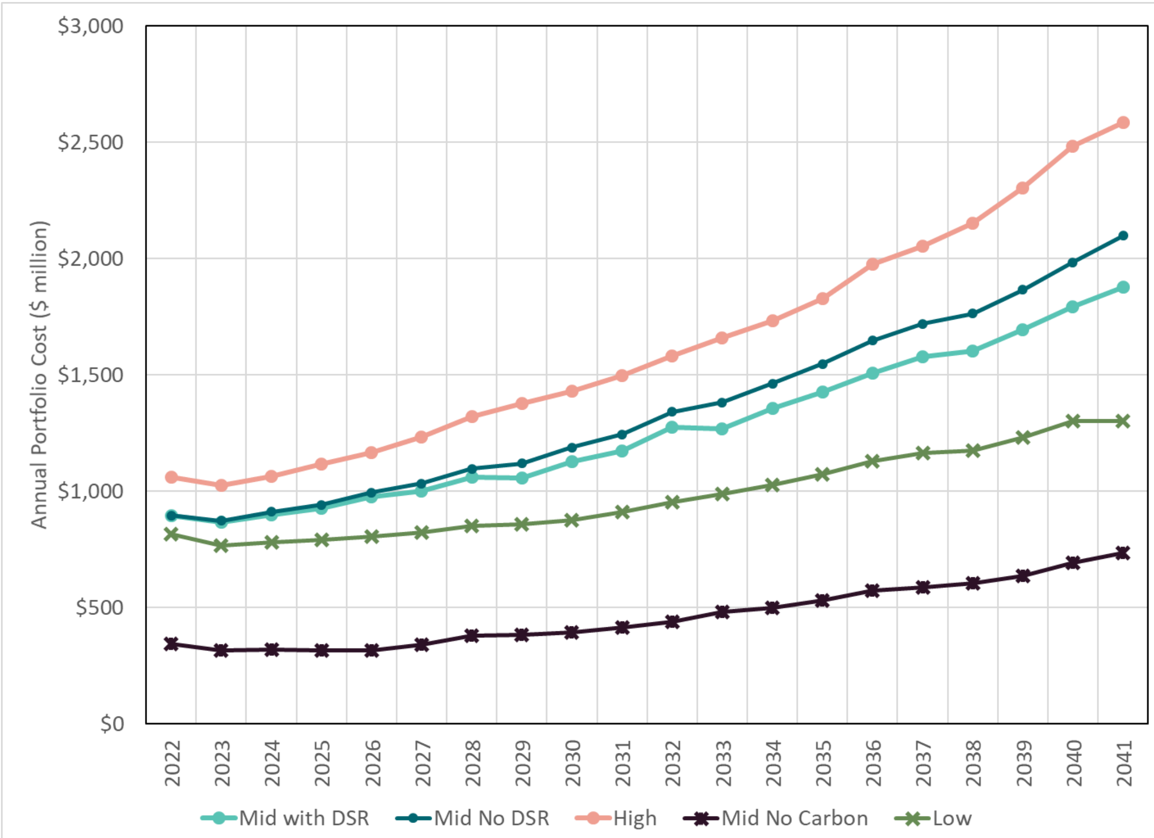


Figure 9-31 shows that average optimized portfolio costs are heavily impacted by natural gas prices and CO_2 cost assumptions included in each scenario.

- The assumed total cost of natural gas supply has the greatest influence on portfolio costs. Natural gas costs were high and relatively close in all three scenarios, and the resulting average portfolio costs were also high and fairly close to each other in comparison to the Mid No Carbon case shown above.
- DSR produces significant savings, as shown by the Mid Scenario with DSR versus the Mid No DSR lines. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Sensitivity Analyses

Five sensitivities were modeled in the natural gas sales analysis for this IRP. Sensitivities start with the Mid Scenario portfolio and change one resource, regulation or condition. This allows PSE to evaluate the impact of a single change on the portfolio.

A. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology.

This sensitivity results in higher emission rates for both the Canadian and U.S. sourced natural gas. Figure 9-32 shows the emission rates for AR4 and AR5.

Figure 9-32: Upstream Emissions for AR4 and AR5

Sensitivity A	(Canadian Supply) gCO2e/MMBtu	(Domestic Supply) gCO2e/MMBtu
AR4	10,803	12,121
AR5	11,564	13,180

AR5 slightly increased total natural gas costs (see Figure 9-33), but made no change to the resource mix in the Mid Scenario. The GPM selected the same level of DSR as in the Mid Scenario, but portfolio costs were higher due to the increased upstream emissions adder (see Figure 9-34).

Figure 9-33: Upstream Emission Costs in $/MMBtu AR4 vs. AR5

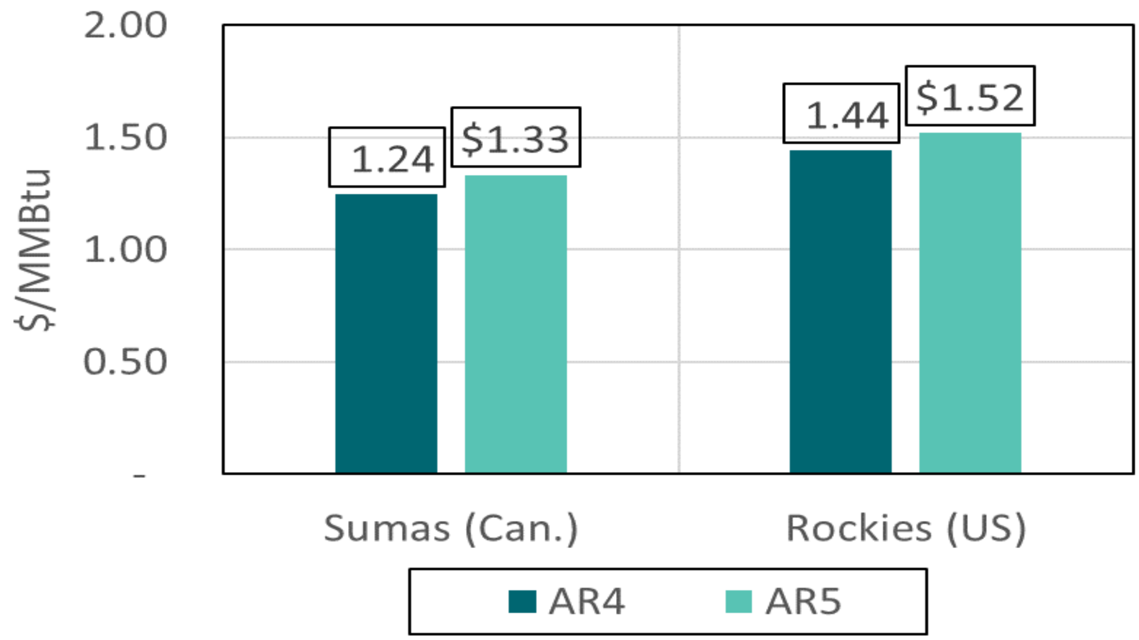


Figure 9-34: 20-year NPV for AR5 Portfolio vs. AR4 Portfolio

Sensitivity A	Portfolio NPV, $ billion
Mid Scenario with AR4	$12.660
Mid Scenario with AR5	$12.758

B. 6-year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effect of faster adoption rates.

BASELINE ASSUMPTION: Conservation measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

The GPM selected the same bundles as in the Mid Scenario, however, the DSR was front-loaded due to the faster ramp rate on the discretionary DSR measures. The overall savings in the 20-year study period did not change (see Figure 9-35), but since the DSR was captured earlier, the NPV of the portfolio was lower (see Figure 9-36)

Figure 9-35: Savings from 6-year Ramp Rate vs. 10-year Ramp Rate

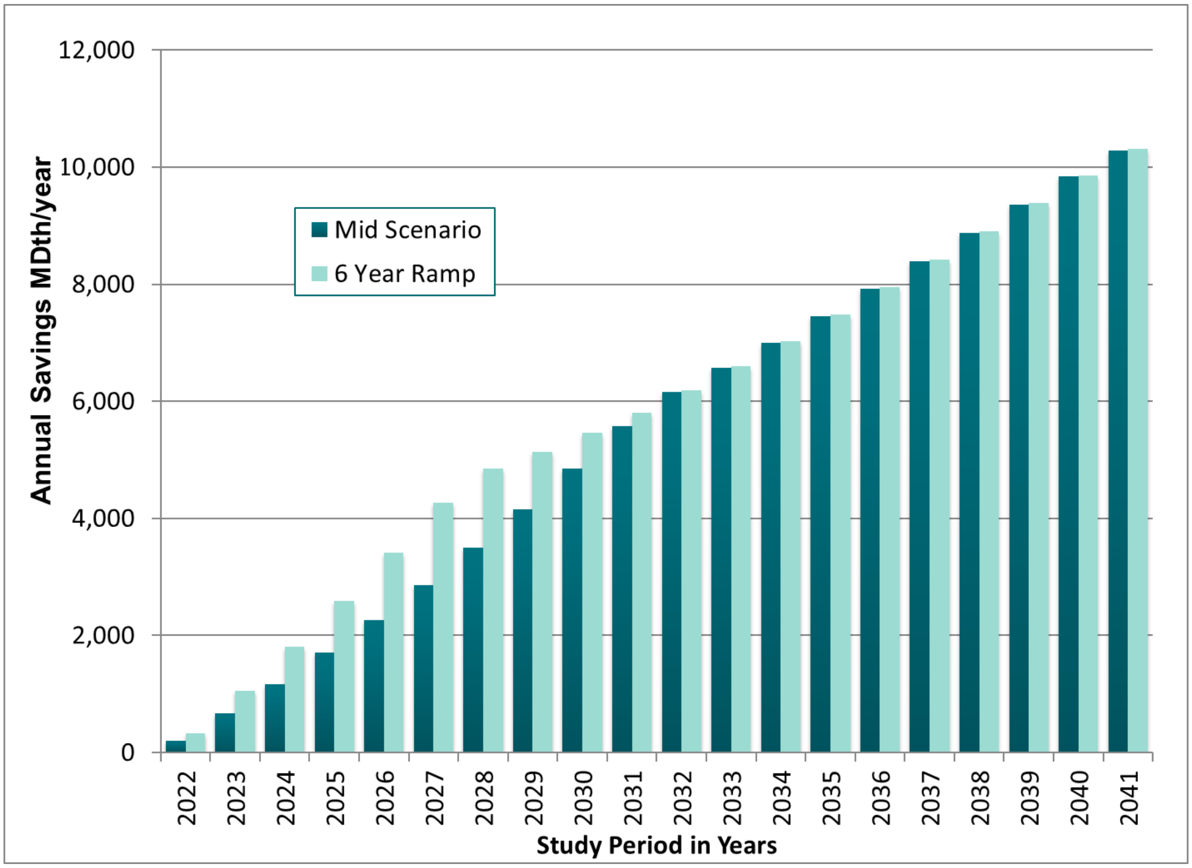


Figure 9-36: NPV for 6-year Ramp Rate vs. 10-year Ramp Rate

Sensitivity B	Portfolio NPV, $ billion
Mid Scenario with 10-year Ramp Rate	$12.660
Mid Scenario with 6-year Ramp Rate	$12.623

C. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

A social discount rate that was lower than PSE's assigned WACC was applied to the demand-side resource alternative in this sensitivity analysis to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as the 2.5 percent nominal discount rate referenced in CETA SCGHG legislation. The 2.5 percent discount rate shifted measures to lower cost points on the conservation supply curve. Since the social discount rate caused the measures to shift to lower cost bundles, the net effect was that cost-effective savings were slightly higher using the social discount rate.

See Figures 9-37 and 9-38 for the DSR savings comparison.

Figure 9-37: Savings by Bundle, 6.8% Discount Rate in IRP Mid Scenario vs. 2.5% Social Discount Rate in Sensitivity C

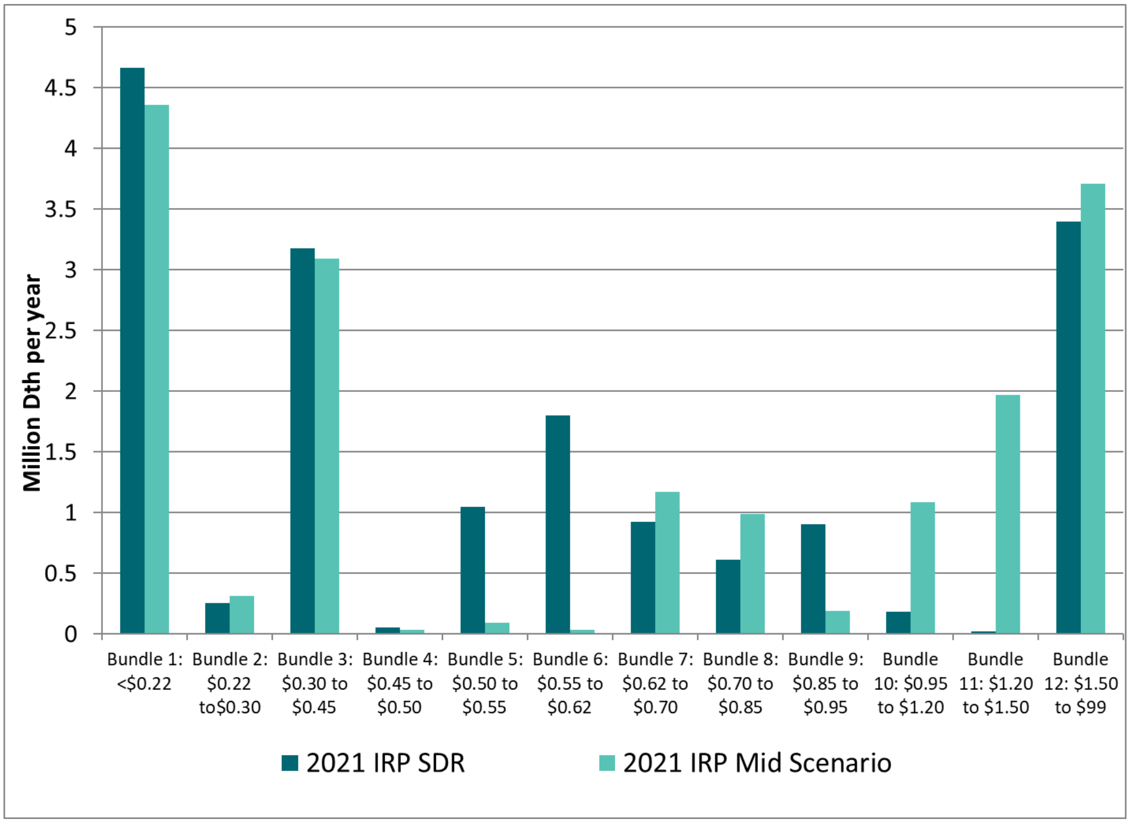


Figure 9-38 Cost-effective Level of Natural Gas DSR, 6.8% Mid Scenario Discount Rate vs. 2.5% Social Discount Rate

Sensitivity C Savings	6.8% Mid Scenario (Mdth/year)	2.5% Social Discount Rate (Mdth/year)
Residential Firm	7,984	9,613
Commercial Firm	2,093	2,107
Commercial Interruptible	39	39
Industrial Firm	156	156
Industrial Interruptible	8	8
Total (MDth per year)	**10,281**	**11,923**

D. Fuel Switching, Gas to Electric

This sensitivity models accelerated adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity illustrate the effects of a rapid replacement of gas end uses with electricity as their fuel on the portfolio and the demand profile of the PSE service territory. For the purpose of this IRP and this gas to electric scenario, electric energy and peak demand potential estimates apply only to PSE's electric service territory and exclude the impacts on other electric utilities. There are many possible fuel switching pathways, and PSE presents this sensitivity as one possible view. Further analysis is required to understand all of the impacts and costs associated with fuel switching.

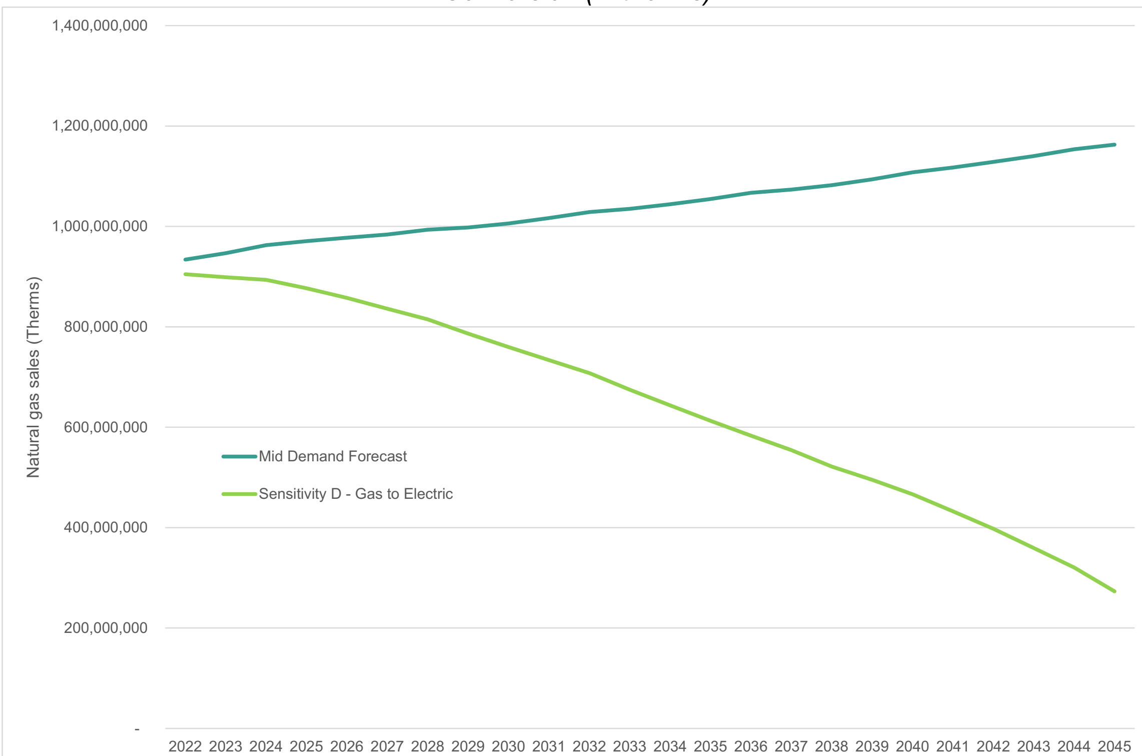
Figure 9-39: Gas to Electric Fuel Switching Assumptions

	Assumption
PSE Customer Base	Energy demand is reduced based on the hybrid heat pumps included in the mid demand forecast for the natural gas portfolio.
Hybrid Heat Pumps	Hybrid heat pumps rolled out for existing and new construction. By 2030, 50% of the total addressable achievable potential will be attained, and by 2050, 100% of the achievable technical potential will be completed. The end uses will include space heating loads with a natural gas backup heat pump.
Other End Uses (water heating, cooking, etc)	Converted to electric uses
Industry Electrification	30% of all the electric loads in the industrial sector are converted from natural gas to electric by 2050

BASELINE ASSUMPTION: The portfolio uses the demand forecast for the Mid Scenario. **SENSITIVITY >** The demand forecast is adjusted to include an accelerated replacement of natural gas end uses with electricity in the PSE service territory resulting in a lower natural gas demand forecast.

This sensitivity looks not only at the impacts to the natural gas portfolio, but it also accounts for the cumulative annual electric energy impacts to PSE's system of converting natural gas equipment for each customer sector. The residential sector shows the biggest impact, accounting for 53 percent and 60 percent of the total cumulative energy impacts in 2030 and 2045, respectively. Compared to the total PSE electric load forecast in the Mid Scenario, these impacts represent additional electric energy loads of 7.9 percent in 2030 and 35.5 percent in 2045, and additional electric peak demands of 6 percent and 17 percent in 2030 and 2045, respectively. For the natural gas sales system, the residential sector accounts for 68 percent of the total natural gas reductions in 2030 and 73 percent of total natural gas reductions 2045. Compared to PSE's total 2019 natural gas sales, natural gas sales decrease by 21 percent by 2030 and 74 percent by 2045.

Figure 9-40: Annual Natural Gas Sales – Mid Demand Compared to Sensitivity D, Electric to Gas Conversion (in therms)

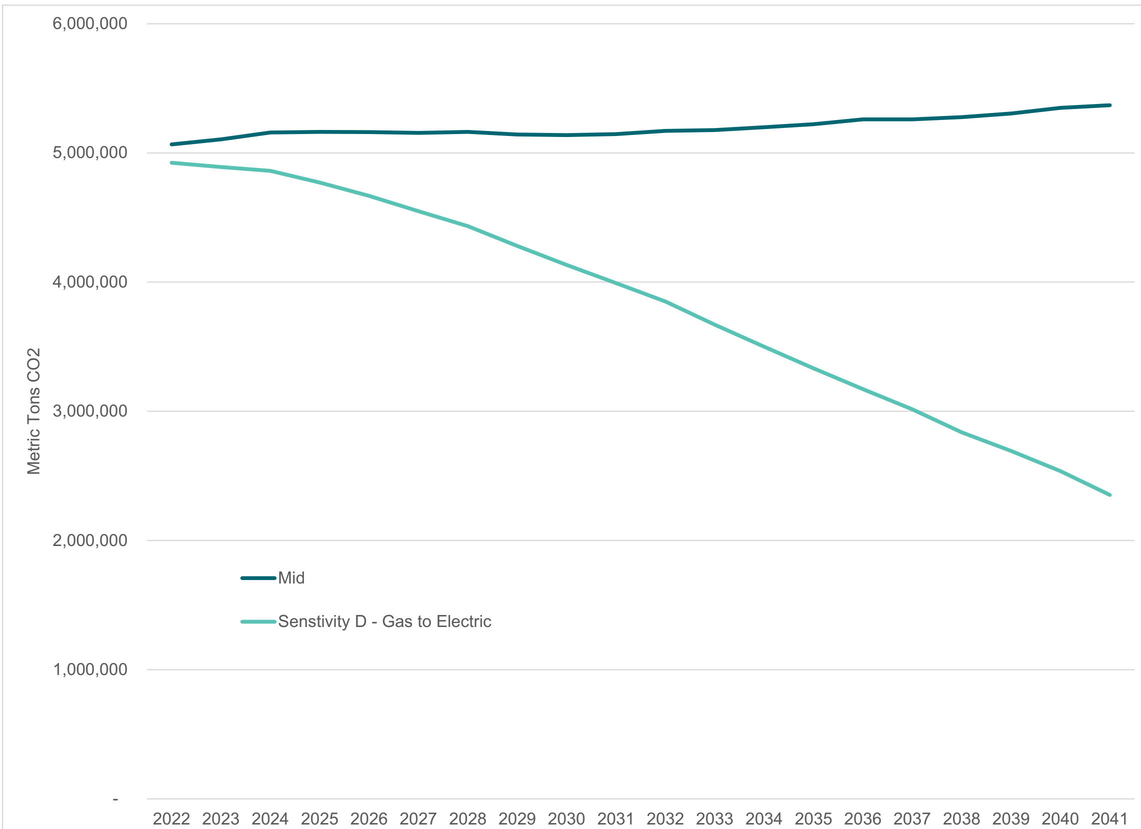


For the residential and commercial sectors, PSE calculated the number of natural gas equipment units that could be converted to electric equipment in PSE's service area for both existing equipment and new construction. Then each natural gas unit was matched to an equivalent electric equipment; annual energy consumption, peak demand and cost assumptions were then applied to the electric equipment to calculate the total impact of conversion.

To mitigate the peak demand impacts of additional winter space heating loads to the electric system, this sensitivity modeled replacing existing residential construction natural gas furnaces with a hybrid air-source heat pump with natural gas backup that switches from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. A full discussion of equipment and impacts by sector is located in Appendix E.

The cost of the conversion was added to the natural gas portfolio. Because of this, portfolio costs increased from $12.66 billion in the Mid Scenario to $14.95 billion in Sensitivity D. The conversion also decreased loads and emissions in the natural gas portfolio. Emissions decreased by 20 percent in 2030 and 47 percent by 2040

Figure 9-41: Natural Gas Emissions – Mid Scenario and Sensitivity D (metric tons CO_2)



Since this sensitivity affects both the natural gas and electric portfolios, combined portfolio costs are also provided. Figures 9-42 and 9-43 compare the combined electric and natural gas portfolio costs for the Mid Scenario and Sensitivity D, and Figure 9-44 compares the direct (generation) and indirect (market) emissions of the combined portfolios. For this analysis, the electric portfolio did not include alternative compliance to achieve carbon neutrality by 2030. Also not included were additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs.

Figure 9-42: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billions $)			
	Portfolio	Electric	Natural Gas	Total	Change from Mid
1	**Mid Scenario**	$15.53	$12.66	$28.19	--
D	**Fuel Switching, Gas to Electric**	$19.56	$14.95	$34.51	$6.32

Figure 9-43: Natural Gas and Electric Annual Portfolio Costs

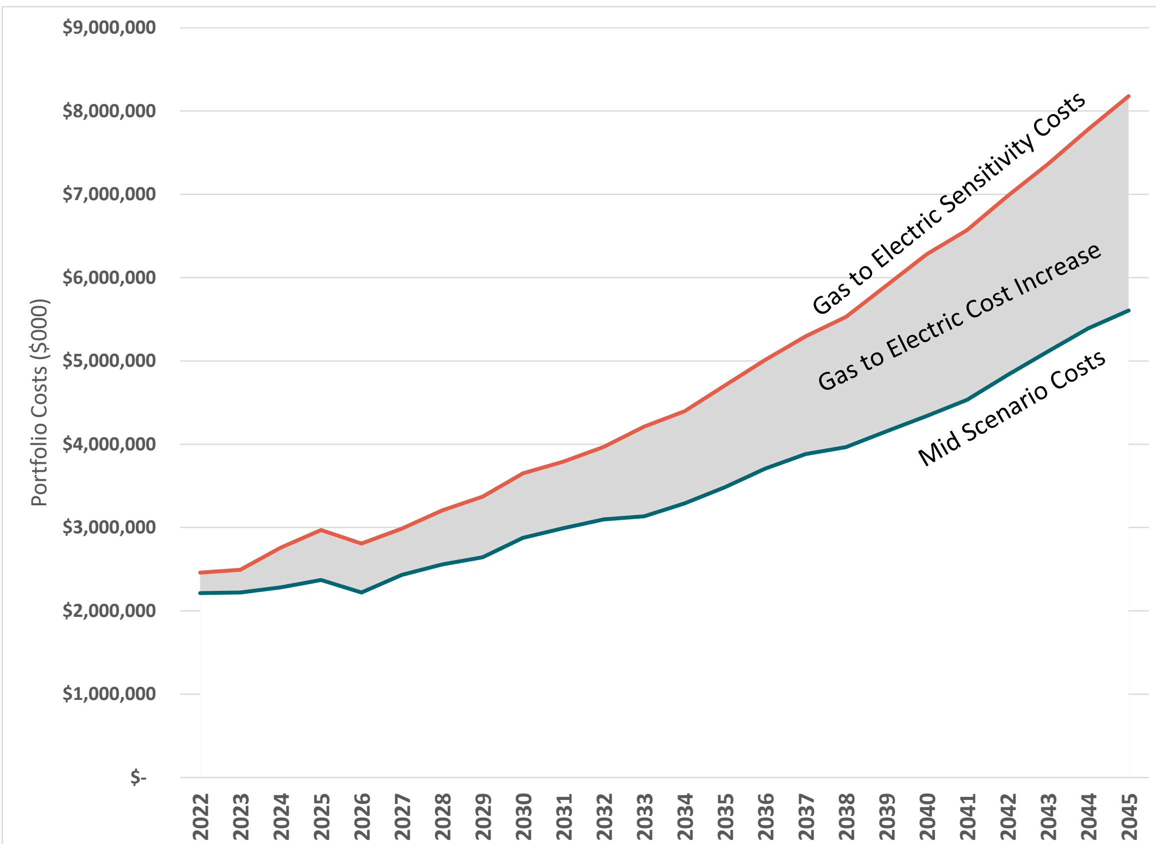
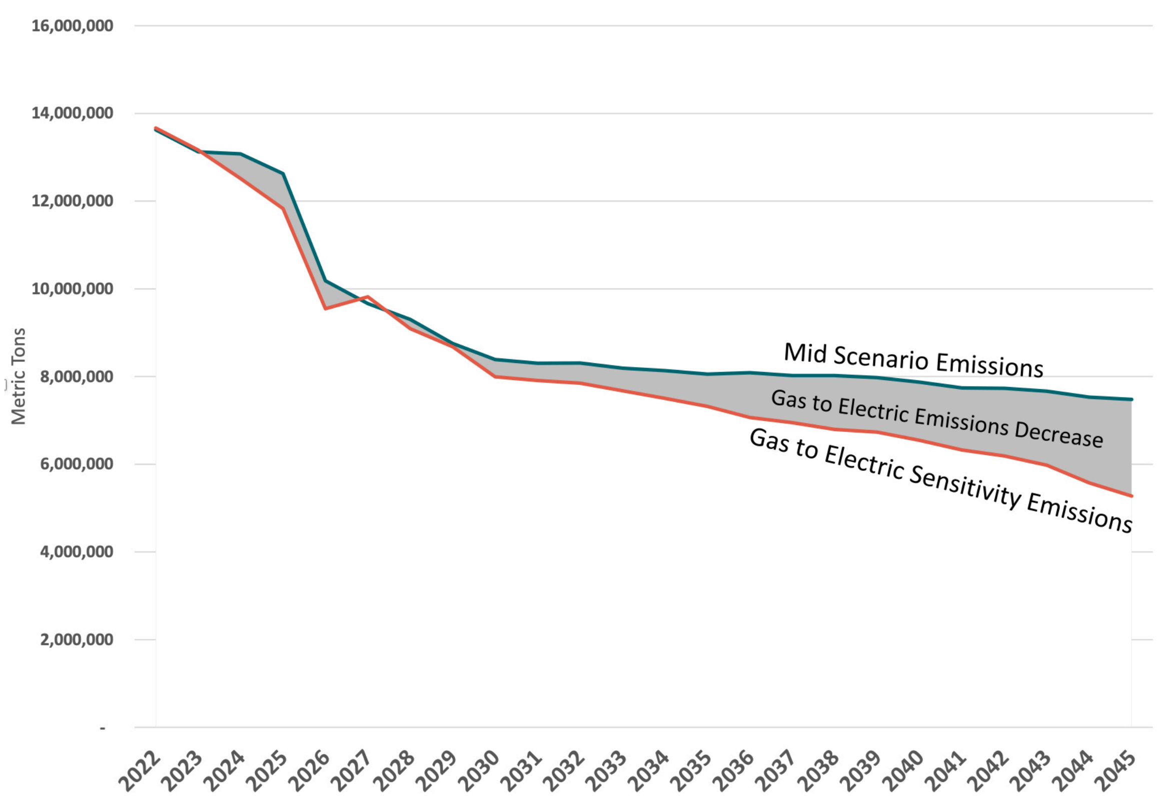


Figure 9-44: Direct and Indirect Portfolio Emissions – Mid Scenario and Sensitivity D, (not including alternative compliance for the electric portfolio)



To put emission reductions into perspective, it is useful to look at the reduction in emissions as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, PSE divides the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 9-45 shows the results of this calculation for Sensitivity D. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent.

Figure 9-45: Cost of Emissions Reduction – Mid Scenario and Sensitivity D

Portfolio	Combined GHG Emissions (millions tons CO_2eq, 24-year levelized)	Combined Portfolio Cost ($ billions, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	116	$28.19	-
D Gas to Electric	109	$34.51	1.11

E. Temperature Sensitivity

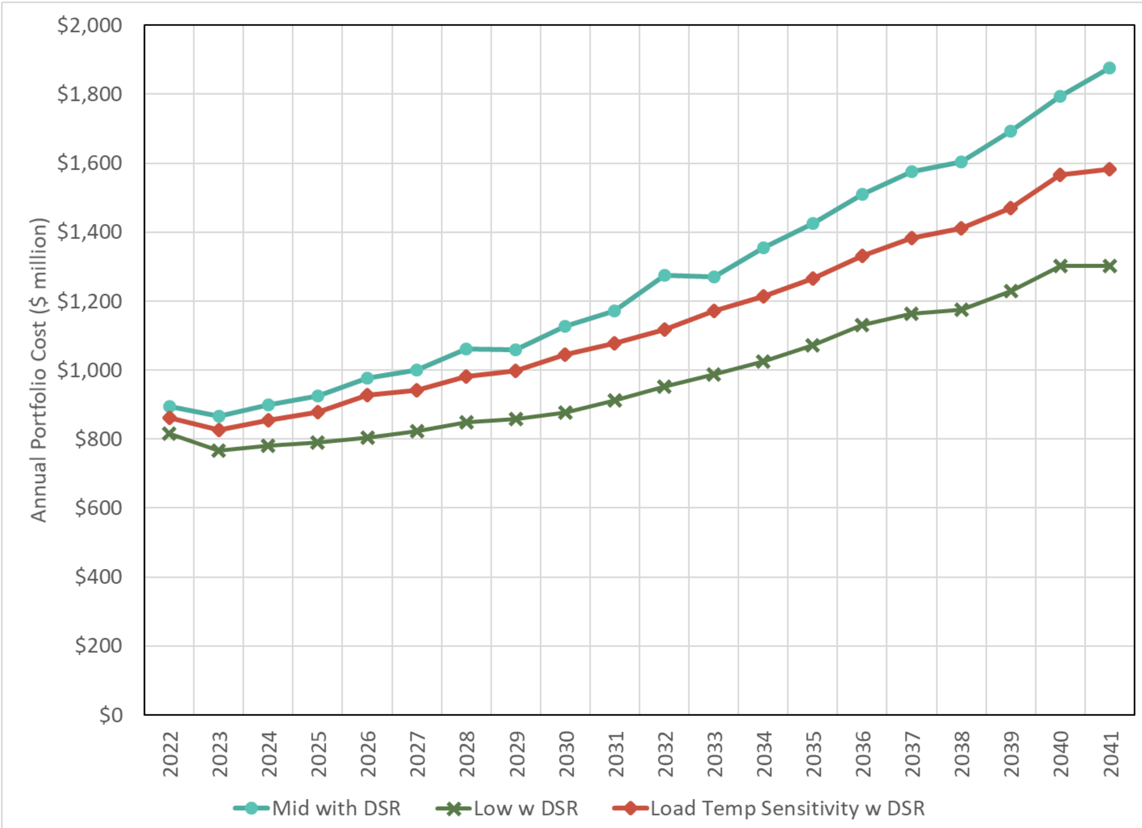
This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: The Base Demand Forecast used in the Mid Scenario is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the past 30 years ending in 2019.

SENSITIVITY > PSE uses temperature data from the Northwest Power and Conservation Council (the “Council”). The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is, therefore, consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council’s climate model.

The temperature sensitivity resulted in higher average temperatures, and a reduction in the load forecast of about 15 percent by 2045. This did not impact the peak design day, so the GPM selected the same resource mix in the capacity expansion; in other words, the same cost-effective DSR was selected as in the Mid Scenario portfolio. Total system costs were slightly lower than the Mid Scenario portfolio, as a lower load led to lower natural gas need, but they were not as low as system costs in the Low Scenario portfolio. This is shown in Figure 9-46 below.

Figure 9-46: Total Portfolio Cost of Natural Gas for Gas Sales Temperature Sensitivity



F. No DSR

This portfolio looks at the benefits associated with demand-side resources.

BASELINE ASSUMPTION: New energy efficiency resources are acquired when cost effective and needed.

SENSITIVITY > No new energy efficiency is allowed in the portfolio and all future needs will be met by supply-side resources.

Because the assumed total cost of natural gas supply has the greatest influence on portfolio costs and natural gas costs were high and relatively close in all scenarios, DSR produces significant savings. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Stochastic Analyses

In order to test the portfolios developed in the deterministic scenario analysis under a wider range of demand and natural gas prices, PSE completed three stochastic runs in the GPM, with each run consisting of 250 draws:

1. **Resource/Cost Optimization**: This analysis tested the Mid Scenario deterministic portfolio against 250 variations (draws) of different demand and natural gas price combinations. The model was allowed to change the resource additions to optimize portfolio cost for the different demand and price conditions.
2. **No DSR Portfolio:** Starting with the Mid Scenario deterministic portfolio and the same 250 variations of demand and natural gas price combinations, this analysis removed DSR as a resource option to learn what other resources would be selected to fill need, and to compare the portfolio costs and risks of the No DSR portfolio with the portfolio optimized with DSR.
3. **Mid Fixed Portfolio:** This analysis tested the robustness of the Mid Scenario deterministic portfolio.The Mid Scenario final resource portfolio was fixed and then run through the 250 demand and natural gas price combinations to evaluate the portfolio's cost and reliability risks.

Development of Input Draws

The development of natural gas price draws and demand draws is the starting point for the stochastic analysis. Eighty natural gas price draws were developed using the risk functionality tool in the electric AURORA model, mirroring the gas price and demand draws used in the electric analysis. For the demand draws, the 250 draws that the load forecasting group used to develop the Low and High Scenarios were used.

NATURAL GAS PRICE DRAWS. For the Sumas, AECO, Rockies and Stanfield natural gas hubs, the natural gas stochastic analysis used the same 80 natural gas price draws developed for the electric stochastic analysis.[12] Natural gas prices for Station 2 and Malin were generated in the GPM using the basis differential pricing off one of the four hubs. The 80 draws were also repeated to create 250 draws. For each hub, a total of 19,200 prices (80 draws x 12 months/year x 20 years), were repeated to obtain 60,000 prices for each hub.

12 / The natural gas price draws were developed from the monthly forecasts that were used in the deterministic models, taking hub and lag correlations into account. See Appendix G, Electric Analysis Models, for a more detailed description of the methodology.

Each natural gas price draw was then adjusted to include the SCGHG and upstream emission adders in the GPM. Figures 9-47 and 9-48 below show the adjustment for Sumas hub for 2022 prices. With the addition of SCGHG and upstream emissions, the expected natural gas price shifted from $2.25/MMBtu to $7.57/MMBtu.

Figure 9-47: Sumas Price Draws for 2022 without SCGHG and Upstream Emission Adders

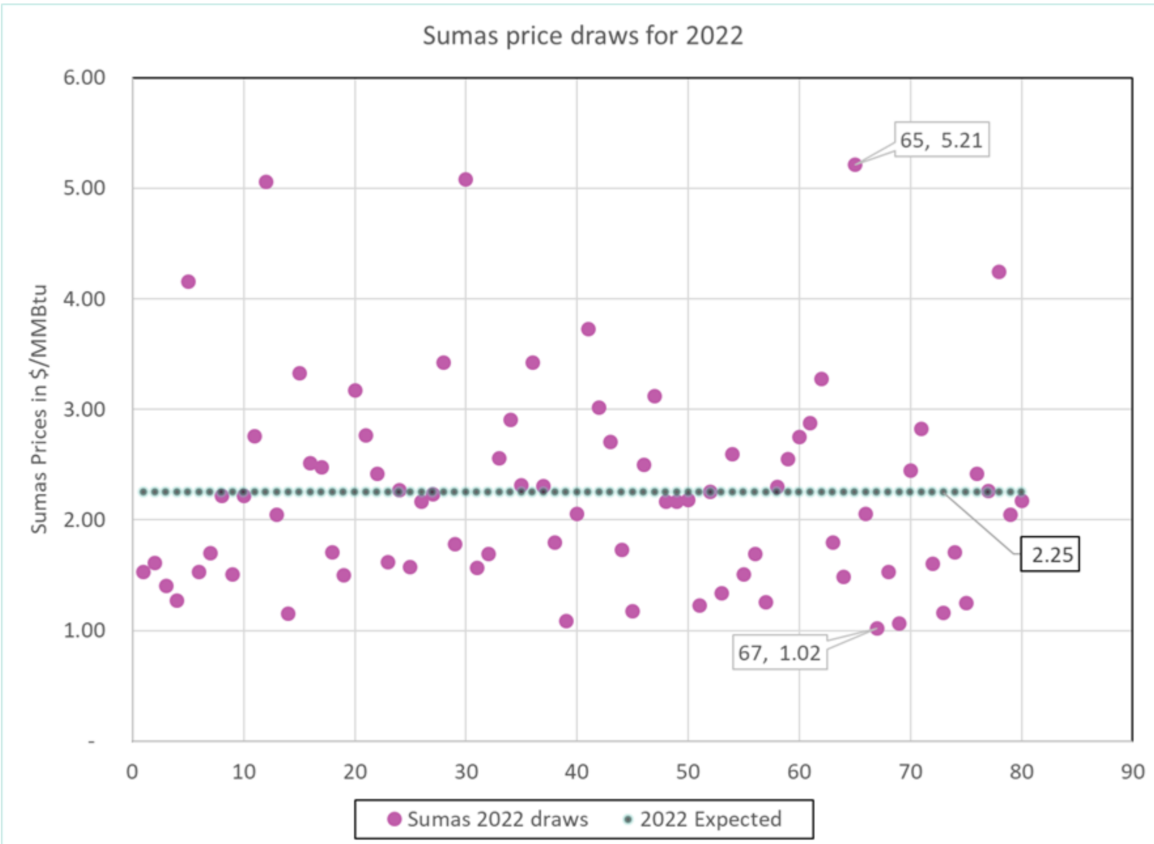
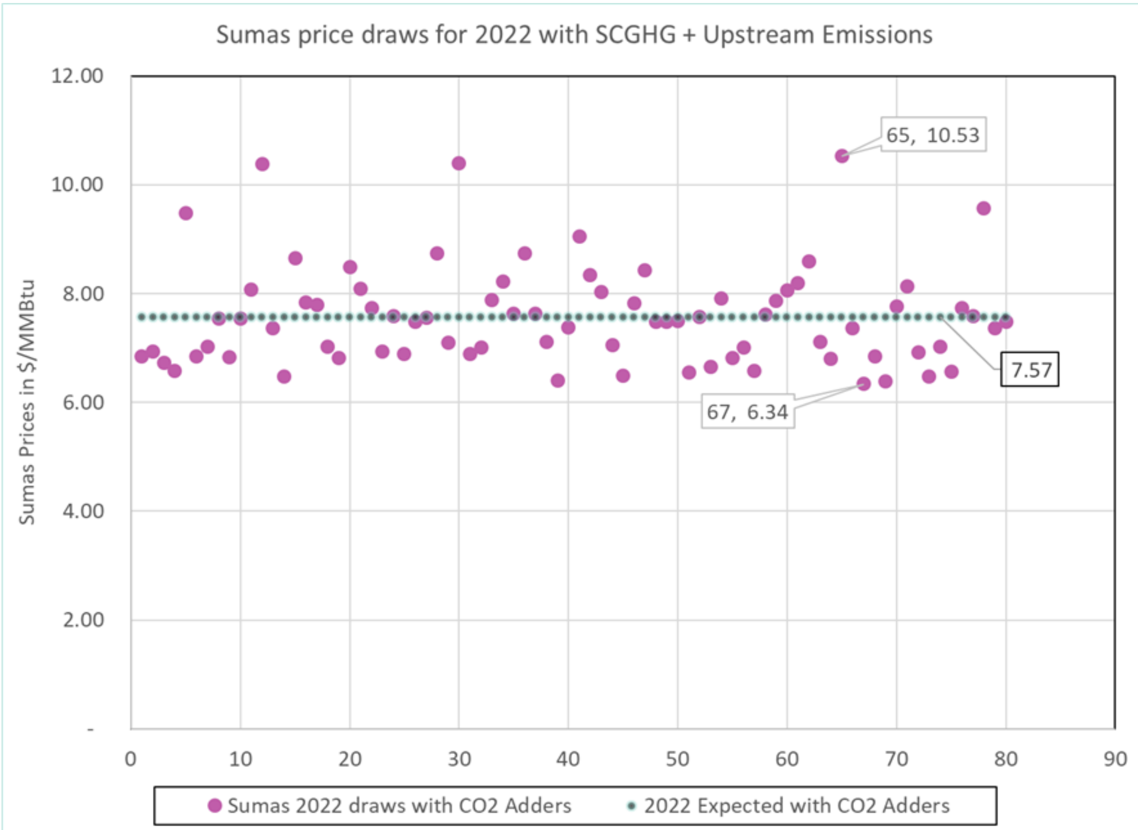
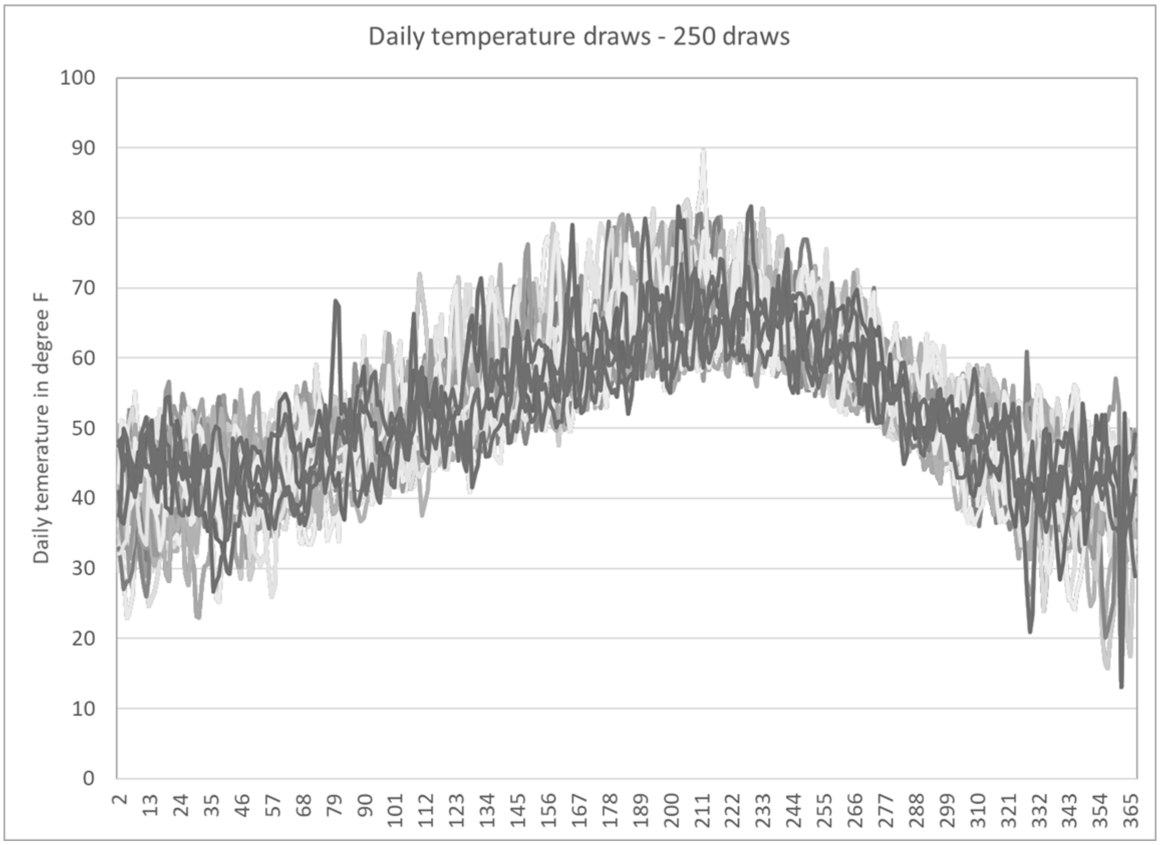


Figure 9-48 – Sumas Price Draws for 2022 after Adjusting for SCGHG and Upstream Emissions Adders



DEMAND DRAWS. The GPM uses temperature draws to calculate demand. The 250 demand draws were developed from the "normal" weather data used in the Base Demand Forecast, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the past 30 years ending in 2019. Before the draws were imported into the GPM, they were adjusted to include the natural gas planning peak day temperature. Figure 9-49 below shows the temperature draws.

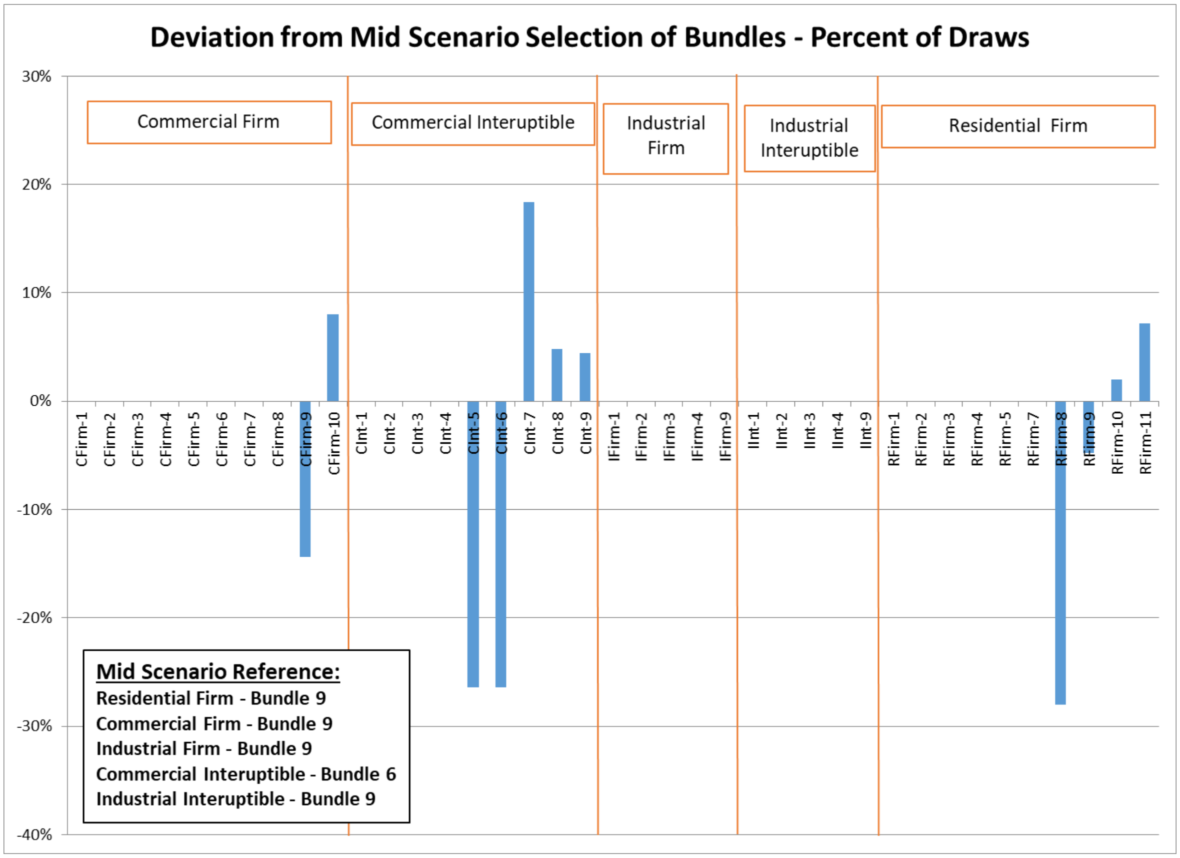
Figure 9-49 – Daily Temperature Draws for Demand



Stochastic Analysis Results

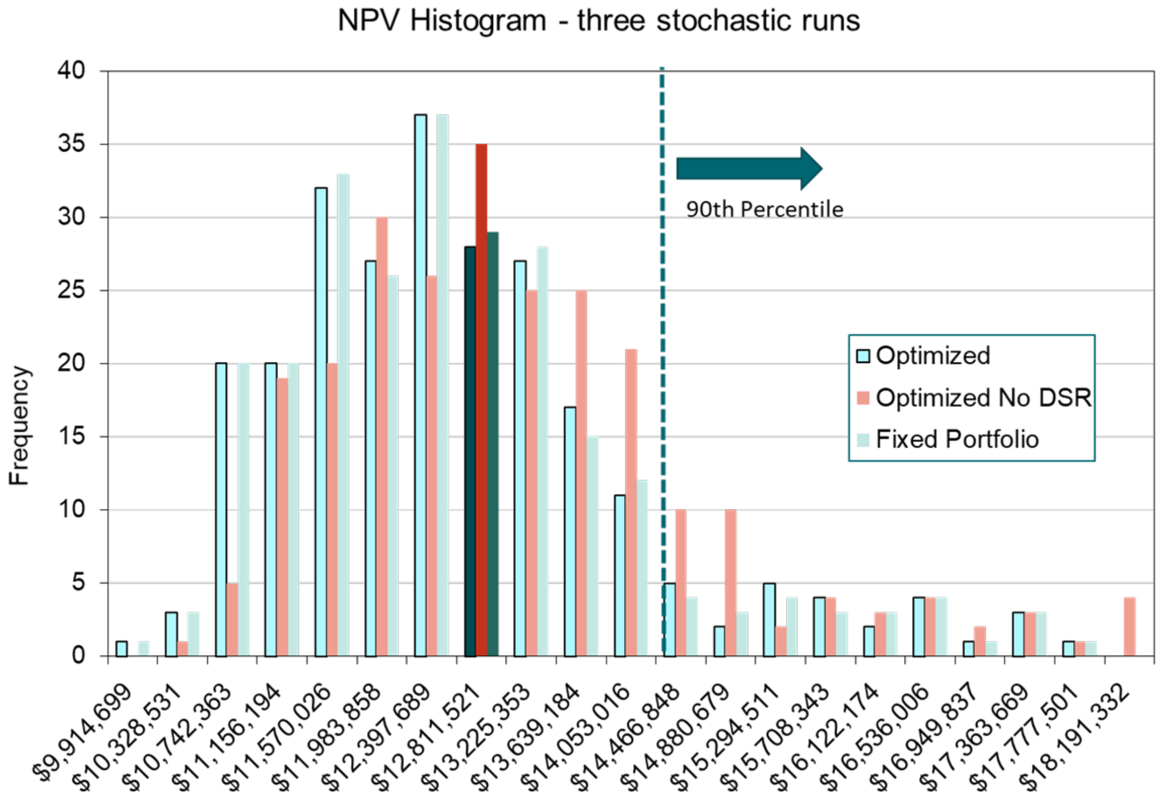
In the 250 optimal portfolios built in the stochastic analysis, the results showed that the DSR quantity chosen in the deterministic scenarios held up in over 80 percent of the draws as shown in Figure 9-50. Therefore, the risk of over-building or under-building DSR appears to be low.

Figure 9-50: Results of DSR Selection in the 250 Fully Optimized Portfolio Runs



The results of all three stochastic analyses are plotted in the histogram shown in Figure 9-51. The portfolio with No DSR has higher costs and more draws in the 90th percentile of total system cost, showing that DSR reduces both cost and risk to the natural gas portfolio.

Figure 9-51: Distribution of Portfolio System Costs



6. NATURAL GAS DELIVERY SYSTEM ANALYSIS

Overview

PSE's natural gas delivery system is responsible for delivering gas safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, PSE must do the following.[13]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at the local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Integrate natural gas supply resources owned by PSE or others.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so infrastructure will be in place when the need arrives.

The goal of PSE's planning process is to fulfill these responsibilities in the most cost-effective manner possible. Through it, PSE evaluates system performance and bring issues to the surface; identify and evaluate possible solutions; and explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as integrity indices, company goals and commitments, and the root causes of historic events. External inputs include service quality indices, regulations, municipality infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended

13 / These obligations are defined by various codes and best practices such as WAC 480-90 Gas Companies - Operations; WAC 480-93 Gas Companies - Safety; WAC 480-100-358:398 Part VI Safety and Standard Rules; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; and Washington Industrial Safety and Health Administration.

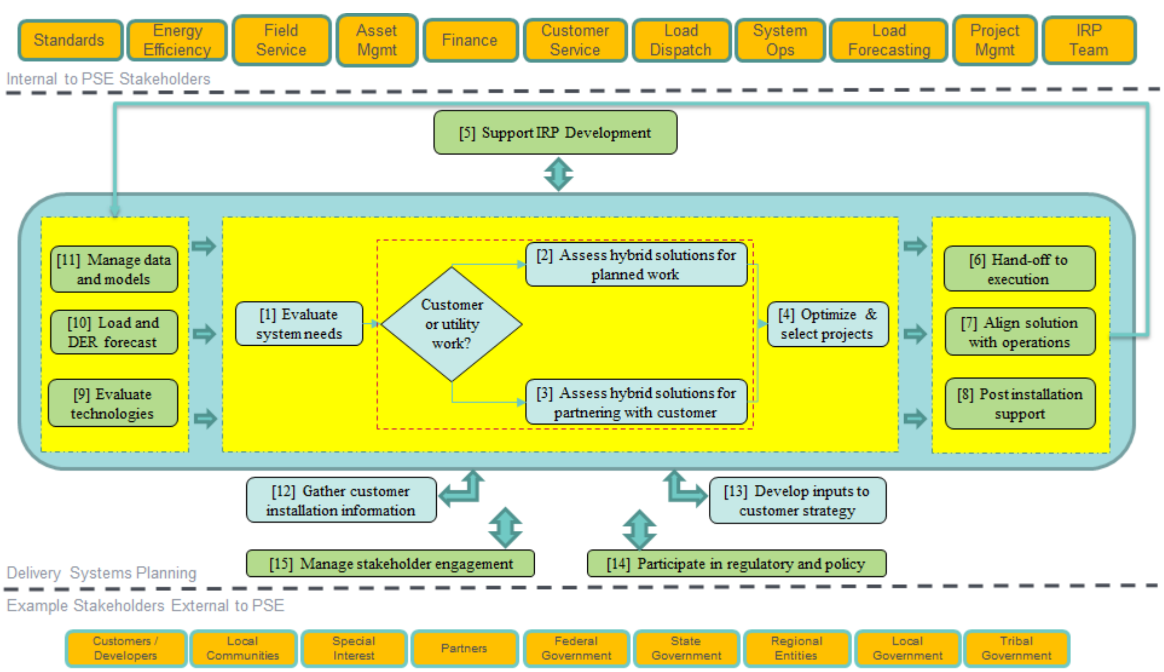
alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term 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.

> > > See Appendix M, 10-Year Delivery System Plan, for the Natural Gas System 10-year plan.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 9-52 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 9-52: PSE Delivery System Planning Operating Model



Natural Gas delivery system needs are driven by a number of different key factors as described below. All of these factors to be considered to identify the right needs across the system.

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. Customer usage patterns determine the peak conditions that the natural gas delivery system must be designed to accommodate. PSE's natural gas load is primarily residential in nature, therefore, peak conditions align with cold-temperature weather events that occur during the winter months (November – March) each year. On a daily basis, the greatest draw on the system occurs between 4 AM and 8 AM, the four-hour period when most households begin their morning routine of waking up to a warm house, taking hot showers and cooking morning meals. It is during these high demand periods that the lowest pressure in the system occurs. Low system pressures that cannot support proper operation of customer equipment affects not only comfort, but safety concerns during a failure event. This requires the operator of the natural gas system to manually close each customer meter until proper pressures are reestablished, perform a safety check and relight each appliance, further inconveniencing the customer. As a result, the natural gas planning criteria is conservative with regard to both the minimum pressures allowed and the anticipated cold weather extremes. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area.

Energy efficiency consists of measures and programs that replace existing building energy using components and systems such as heating, water heating, insulation, appliances, etc., with more energy efficient ones. These replacements can reduce both peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress, system imbalance or in response to market prices are participating in demand response (DR). Interruptible rates are a subset of demand response. When used to relieve loading at critical times, demand response can offset anticipated loads and reduce the need for traditional delivery infrastructure. Interruptible rates are used in PSE's service area, and there is a high dependence on curtailment of these customers in order to meet demand.

RESOURCE INTEGRATION. 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 natural gas generation facility will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life create integrity issues potentially causing leaks or failure to operate when needed.

SYSTEM INTEGRITY. Pipeline and Hazardous Materials Safety Administration (PHMSA) require PSE to monitor and remediate risks to both the natural gas transmission and distribution programs.

OPERATIONAL FLEXIBILITY. The ability to isolate pipelines and transfer load, is important in responding to unplanned and planned outages, and the ability to perform necessary maintenance on equipment.

DISTRIBUTED ENERGY RESOURCES. While more commonly discussed in the context of the electric system, natural gas generators can impact demand as well and must be considered.

SAFETY AND REGULATORY REQUIREMENTS. These requirements drive action for mitigation in short order and/or are dictated through contractual agreements and as a result are identified and resolved outside of this long term planning process.

The energy delivery system is reviewed each year to ensure pipeline integrity and mitigate risk. Past leaks, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements mitigate elevated risks to the public and PSE's customers. PSE collects system performance information from field charts, remote telemetry units, SCADA, employees and customers. Per regulation, PSE has a robust distribution integrity management program and a transmission integrity management program that requires a risk based approach to identify and mitigating integrity concerns. Programs to address these risks are implemented, often resulting in the replacement of assets or increased monitoring. Programs are also in place to address aging infrastructure by replacing pipelines that are nearing the end of their useful life.

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, are also included in the system evaluation. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost. For example, the WUTC issued a policy statement in 2012 allowing 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. In 2016, the NTSB recommended the pipeline industry develop guidance on safe pipeline operations to ensure protection of communities and the environment. The Pipeline Safety Management System (PSMS) helps operators understand, manage and continuously improve safety efforts at any stage of their safety programs through a Plan-Do-Check-Act cycle. The PSMS is intended to provide the tools needed to continuously and comprehensively track and improve safety performance. 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 transportation projects develop through design, engineering and construction, PSE works with local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 9-53 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,[14] which then creates a full understanding of all the benefits and risks.

Figure 9-53: Natural Gas 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
Gas Outage Spreadsheet	Gas outage predictive analysis	Gas Synergi system performance data for future capacity	Predicted outage savings
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
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

14 / Investment Decision Optimization Tool which is a software tool called Folio by PwC.

PSE's natural gas system model is a large integrated model of the entire delivery system using a software application (Synergi® Gas) that is updated to reflect new customer loads and system and operational changes. This modeling tool predicts capacity constraints and 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.

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. For natural gas, this includes the diameter, roughness and length of pipe, connecting equipment, regulating station equipment and operating pressure. 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 (CIS) or actual telemetry 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.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 9-54. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission, bulk distribution (high pressure) and distribution (intermediate pressure), as well as for capacity[15] and reliability. A "need" is identified when performance criteria is not met.

15 / New methods of extracting and producing natural gas have accessed vast reserves of natural gas in the U.S. and North America. This has resulted in U.S. gas prices falling to levels not seen since the 1970s. In response to these depressed market prices, processing facilities no longer find it economic to strip out the heavier hydrocarbons (ethane, propane, butane, etc.) often found in raw natural gas. This has had the unexpected effect of increasing the Btu content[15] of the gas received from historic levels of 1,030 btu per standard cubic foot to more than 1,100 btu per standard cubic foot, essentially increasing system throughput capability by five to 10 percent, avoiding pressure and capacity concerns that need addressing. A change in gas quality (lower btu gas), while still within required tariffs, may result in more system analysis.

Figure 9-54: Performance Criteria for Natural Gas Delivery Systems

Gas delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (52 DD Peak Hour)
The nature of service each type of customer has contracted for (firm or interruptible)
The minimum pressure that must be maintained in the system (level at which appliances fail to operate)
The maximum pressure acceptable in the system (defined by CFR 192.623 and WAC-480-93-020)
The historical or future pipeline integrity performance indicators that elevate risk relative to safety or methane release which may be caused by aging infrastructure, third party damage, or equipment location or condition.
The ability to remove equipment from service for maintenance and provide flexibility for emergency response.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursuing electrification, demand side resources dependency at the local neighborhood level, and deferral of traditional infrastructure. PSE expects delivery system planning margins to increase to account for operating concerns relating to behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response, have historically incorporated outputs generically, but these assumptions, while appropriate for resource planning, may not be appropriate for local neighborhood decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE engages with WUTC pipeline safety staff in various forums such as annual audits and quarterly roundtable discussions that also inform PSE's considerations about concerns and solutions.

Solutions Assessment and Criteria

The alternatives available to address delivery system capacity, integrity, aging infrastructure, and operational flexibility are listed below. Each has its own costs, benefits, challenges and risks.

Figure 9-55: Alternatives for Addressing Delivery System Capacity and Reliability

ALTERNATIVES	NATURAL GAS SYSTEM
Add energy source	City-gate station; District regulator
Strengthen feed to local area	New high pressure main; New intermediate pressure main; Replace main
Improve existing facility	Regulation equipment modification; Uprate system
Load reduction	Conservation; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases.

PSE is monitoring and investigating technologies that will prove to be useful low carbon alternatives in the future including renewable natural gas injection into a needed location, hydrogen blending similar to renewable natural gas, greater use of demand response through smart thermostat technologies, and higher efficiency and hybrid or dual fuel customer equipment.

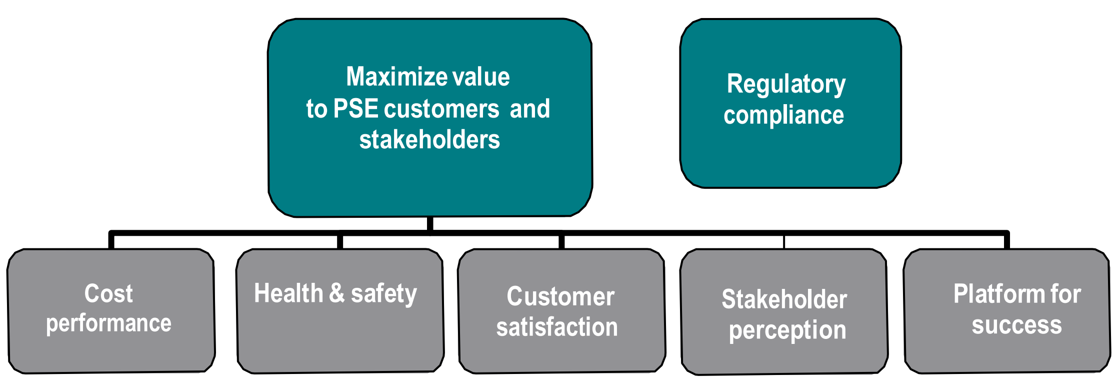
The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

- Temporary adjustment of regulator station operating pressure as executed through PSE's Cold Weather Action Plan
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles and liquid natural gas injection vehicles

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 9-55 as well as consideration of the avoidance of adverse impacts to integrity or operating characteristics and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the iDOT Tool. iDOT is a project portfolio optimization based on PriceWaterhouseCooper's Folio software that allows us to capture project and program criteria and benefits and score them across thirteen factors associated with 6 categories. These include meeting required compliance with codes and regulations; net present value of the project; improvement to integrity, reliability and safety; future possible customer/load additions; deferral or elimination of future costs; customer satisfaction; improved external stakeholder perception; and opportunities for future success gained by increasing system flexibility or 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 9-56: 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 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 for example 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.

iDOT builds a hierarchy of the value these benefits bring to 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 natural gas system infrastructure projects 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 known permitting or environmental process concerns. Periodically, PSE has reviewed this process and the optimization tool along with the resulting portfolio with WUTC staff.

The iDOT tool also helps PSE examine projects in greater detail than a simple benefit/cost measure. iDOT includes factors such as brand value, health and safety improvements, environmental impact, sustainability, customer value and stakeholder perception. As a result, projects that contribute intangible value receive due consideration in iDOT.

Future iDOT enhancements could incorporate benefits such as carbon emissions reduction or methane emissions reduction benefit, more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100 percent clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric and natural gas energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. PSE’s delivery system planning process will mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-pipe Alternative Analysis

PSE's planning process has incorporated non-pipe alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-pipe alternative analysis is a screening process that breaks down of the problem utilizing existing resources, emerging technologies like renewable natural gas injection and hydrogen blending, or reducing customer demand, performs an economic and feasibility analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional pipeline solution, a full non-pipe solution, and any potential hybrid across the problem components.

All types of pipeline alternatives are considered, but some key facts must be considered:

- PSE has an obligation to serve existing natural gas customers within its certificate area approved by the WUTC.[16]
- PSE has an obligation to new natural gas service requests as long as a customer meets the tariff requirements,[17] and PSE is not authorized under Washington State to abandon its natural gas service for all, nor is it authorized to pay to electrify natural gas customers

With these facts as backdrop, PSE is committed to decarbonizing the natural gas system, pursuing greener energy and maximizing natural gas energy efficiency and the IRP highlights that opportunity to meet all future growth with demand side resources. Capacity needs may be able to be met with technologies such as demand response and more energy efficiency and understanding local customer behavior and adoption will be important to see these opportunities realized.

With the learnings of a more mature electric non-wire alternatives analysis, PSE has begun similar analysis in the natural gas system. More detail can be found in Appendix M.

16 / RCW 80.28.190
17 / RCW 80.28.110

Project Planning and Implementation Phase

Once the above process for a particular project and portfolio is completed, reviewed by senior management and approved for funding, the Delivery System Planning initiation phase is complete and the project planning phase begins. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects this may be captured in PSE's SAP system through a notification process or supported from a business case that addresses needs programmatically. The project planning phase involves detailing engineering and technical specifications, pursuing real estate right-of-way needs, planning stakeholder communications and considering potential coordination with other projects in the area. Implementation risks are assessed and mitigation plans are developed as needed. PSE's 10 year plan included in Appendix M reflects projects that are largely in project initiation. Once a project moves to the project planning phase, the need has been established and IRP stakeholder engagement ends while community engagement begins.

Once project need and initiation recommendations are reviewed, annual and two-year work plans are developed for project planning and implementation feasibility. Work plans are coordinated with other internal and external work and resource plans are developed. 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 the total portfolio financial forecast remains within established 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 project lifecycle phase gates and through detailed routing and siting discussions.

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 project planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.